March/April 2018

Leveraging Drones for PV Plant Inspections

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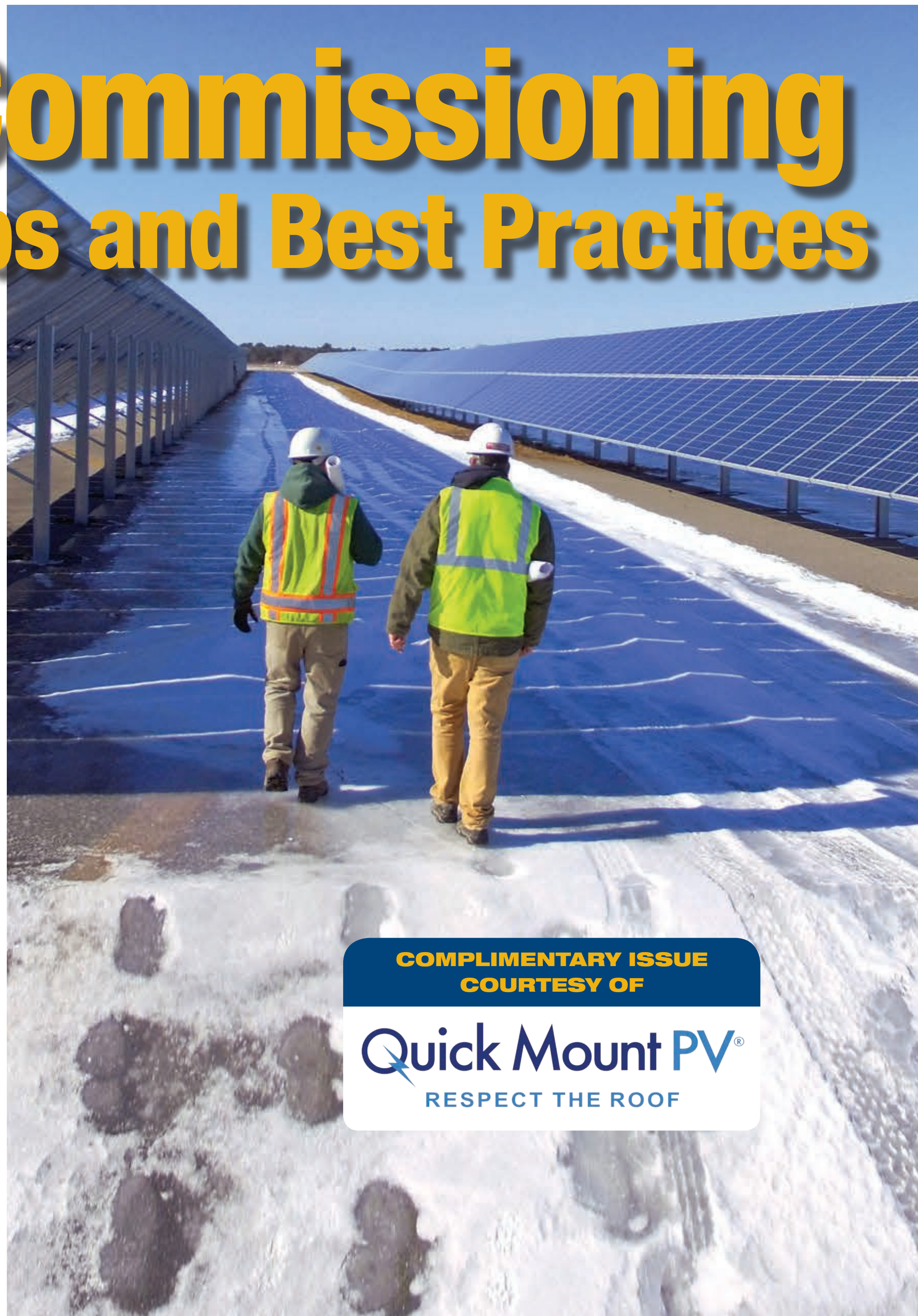
PV Commissioning
Tips and Best Practices



Calculating PV Degradation

Using Open-Source Software to Quantify Degradation Rates

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Amicus O&M Co-op

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Sun Light & Power

ReVision Energy
Brunswick Landing
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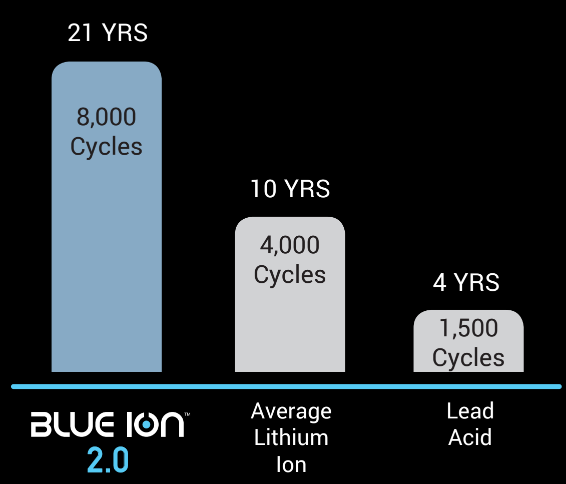

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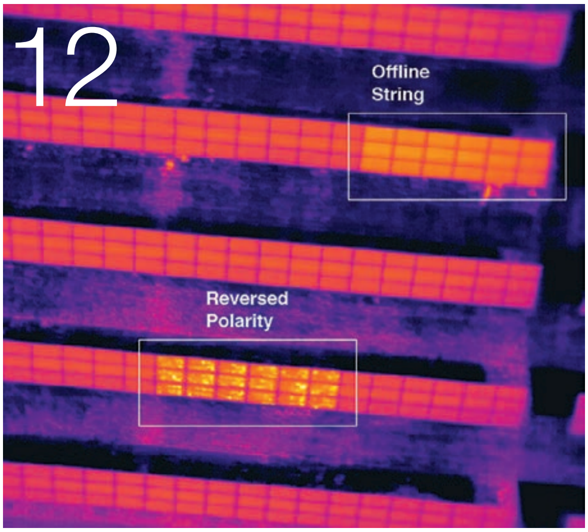
ON THE COVER ReVision Energy's Zach Good and Josh Baston head out to survey the 1.5 MW PV installation at Brunswick Landing in Brunswick, Maine. Brunswick Landing, a sprawling business park with diverse businesses and loads, is a renewably powered microgrid that operates as a single metered customer of the local utility. The site was redeveloped from the former Naval Air Station Brunswick. ReVision Energy developed and built Brunswick Landing's PV plant with financing assistance from a local company, Diversified Communications. The project deploys REC TwinPeak 345 W modules, SMA Tripower inverters and Schletter G-Max racking. Photo: Courtesy ReVision Energy



Contributors

Experience + Expertise

Nate Goodell, PE, is part of Taitem Engineering's Energy+Sustainability team, focusing primarily on commissioning, measurement and verification. In addition, Goodell built and runs the Taitem solar pile testing rig and has worked on 60-plus PV design projects. He is a BCA Certified Commissioning Professional.

Katherine A. Jordan, a writer and consultant for renewable energy, bridges information between stakeholders and scientists. An advanced statistics advocate for improving performance in R&D, Jordan has 19 years' experience editing scientific publications in semiconductors, materials science and field performance of photovoltaics.

Dave Tedeyan works for Taitem Engineering's renewables department, managing and performing service work, O&M, commissioning, and design and installation of battery-based systems. He has a background in electrical engineering with a BS from Bucknell University.

Nikhil Vadhavkar is the CEO of Raptor Maps, an artificial intelligence company specializing in drone data analytics. He supports PV asset owners, EPC and O&M firms. Vadhavkar previously developed thermal control systems for advanced spacesuits at MIT and led a Gates Foundation grant for deploying drones to deliver medical supplies in developing nations.

Gordon Woodcock manages Taitem Engineering's renewables department. His solar PV career started in 2007, following years as a hydrogen fuel cell engineer. He has worked for a number of EPC firms and inverter manufacturers. Woodcock has a BS from the University of Colorado and an MBA from the University of New Mexico.

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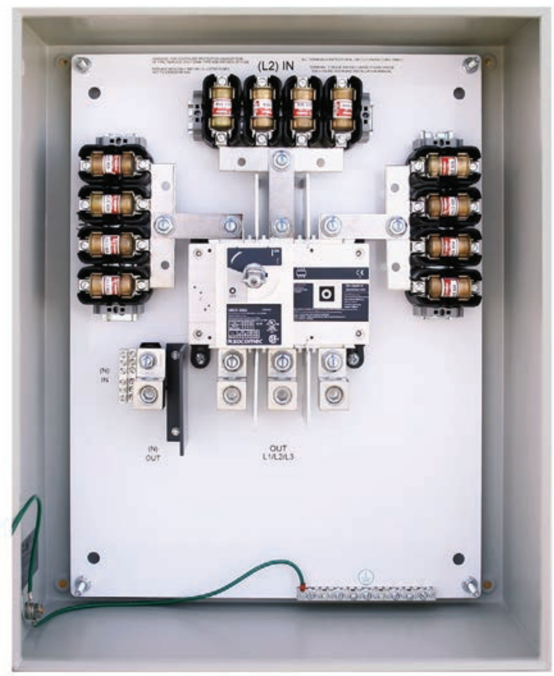
SolarBOS Expands AC Combiner Line



[Livermore, CA] SolarBOS introduced its AC Combiner product family in September 2016 and has continued to refine and expand the line's functionality and available options. SolarBOS AC Combiners are customizable for a wide range of solar projects. Custom output busses allow direct and convenient connection to a transformer. Other options include integrated input or output disconnects, auxiliary breakers, integrated SCADA monitoring components, convenience receptacles, preterminated custom-length input conductors and surge protection. Technical highlights of the customizable ac combiners include bidirectional fuses, inverter isolation, reduced personal protective equipment requirements, OCPD coordination and specific solutions for supply and load applications.

SolarBOS / 925.456.7744 / solarbos.com

Solaria Introduces Residential Module via Soligent Installer Network

[Fremont and Petaluma, CA] Soligent's network of 5,000 installers began deploying Solaria's new high-power 350 W STC module on residential rooftops during Q1 this year. Solaria has built the PowerXT 350 module on its proprietary technology that couples large-format monocrystalline cells with advanced cell interconnect and module production processes. The result is a 60 cell–equivalent module with a seamless, uniform appearance. Its black backsheet and frame create an aesthetically pleasing product for residential applications. Solaria backs its PowerXT 350 module with a combined 25-year power and product warranty.

Solaria / 510.270.2500 / solaria.com
Soligent / 800.967.6917 /soligent.net

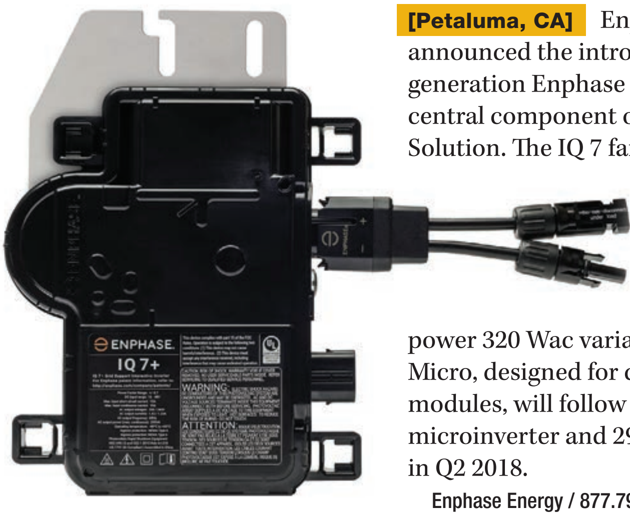
NABCEP Hosts Continuing Education Conference

NABCEP Continuing Education CONFERENCE
March 19-22, 2018 / Niagara Falls, NY

[Clifton Park, NY] The North American Board of Certified Energy Practitioners (NABCEP) is hosting its seventh annual continuing education conference March 19–22 at the Conference & Event Center in Niagara Falls, New York. Educational trainings begin Tuesday, March 20, at 8am and end on Thursday, March 22, at 4:30pm. The event-hosted lodging, Sheraton at the Falls Hotel, is adjacent to the convention center. In addition to offering one of the premier opportunities to network with experienced solar design, installation and sales professionals from across the US, the conference is also an opportunity for NABCEP Certified PV Installation Professionals and PV Technical Sales Professionals to obtain all of the continuing education credits needed for recertification (18 hours every three years).

NABCEP / 800.654.0021 / nabcep.org

Enphase Releases Seventh-Generation IQ Microinverters



[Petaluma, CA] Enphase Energy recently announced the introduction of its seventh-generation Enphase IQ microinverters, a central component of its Enphase Home Energy Solution. The IQ 7 family of microinverters generates 4% more power, is 19% lighter and is 17% smaller than the IQ 6 family. A new high-power 320 Wac variant, the Enphase IQ 7X Micro, designed for compatibility with 96-cell modules, will follow the 250 Wac Enphase IQ 7 microinverter and 295 Wac IQ 7+ microinverter in Q2 2018.

Enphase Energy / 877.797.4743 / enphase.com

Tigo and SMA Announce TS4 Rapid-Shutdown Solution

[Los Gatos and Rocklin, CA] Tigo Energy and SMA America have announced a new SunSpec-compatible module-level rapid-shutdown unit, the TS4-F (Fire Safety). The solution joins the current TS4 platform with a focus on emergency responder safety. It uses module-level power electronics technology to

provide cost-effective rapid-shutdown functionality. The new product meets UL 1741, *NEC 2014* and *NEC 2017* requirements, including stricter regulations for the area inside the array boundary, which will be effective in some jurisdictions in January 2019. The TS4 rapid-shutdown device is offered in two formats. The TS4-F is designed for factory integration with a PV module. The field-installed TS4-R-F is used in conjunction with standard modules.

Tigo Energy / 408.402.0802 / tigoenergy.com
SMA America / 916.625.0870 / sma-america.com

First Solar Introduces Series 6 Modules

[Tempe, AZ] First Solar has launched its Series 6 module, manufactured for utility and large C&I PV power plants. The new module includes some significant design variations compared to First Solar's smaller-format and lower-power Series 4 (110 W STC–122.5 W STC) frameless thin-film laminates. The Series 6 is a large-format module (79.1 by 48.5 by 1.9 inches) with power ratings of 420 W STC–445 W STC. The modules are designed for two-person installation. In a departure from First Solar's previous laminate designs, the Series 6 features an under-mount frame with versatile mounting that is compatible with leading fixed-tilt and tracking systems. The under-mount frame maintains the cleaning and snow-shedding benefits of a frameless module, while protecting edges against breakage and enabling horizontal stacking. Additionally, the Series 6 has a dual junction box design, eliminating the need for wire management for module-to-module connections.

First Solar / 877.850.3757 / firstsolar.com

Leveraging Drones for PV Plant Inspections

Drones are reducing labor costs, maximizing performance and providing granular insights for PV systems. In addition to enabling the taking of aerial photos, they support aerial thermography, capturing PV system performance data with thermal infrared (IR) cameras.

Also known as an *unmanned aerial vehicle,* a drone is an aircraft without a human operator aboard. A drone in combination with a ground station, typically a smartphone or tablet and controller, comprises an *unmanned aerial system.* Drones can be either fixed-wing types, which resemble an airplane, or multicopter models, which have several propellers and can hover in place.

Locating the failure point A drone equipped with a thermal imaging camera detected this PV string failure in minutes on a 4 MW installation. The maintenance technician located the failure with the drone before determining the cause of failure in the array field.

Courtesy Raptor Maps

O&M providers, EPC firms and asset owners are increasingly adopting drone technology for its lower data acquisition costs and superior data collection and analysis flexibility compared to boots-on-the-ground inspections with handheld analysis tools. In the past 2 years, machine learning and artificial intelligence, improvements in drone hardware and a favorable regulatory environment have combined to push drones to the forefront of aerial thermography.

"This year, we are flying drones over most of our power plants under management," says Angelo Purpura, director of operations at SOLV, a Swinerton company. "Asset owners are recognizing that drones can replace the majority of I-V curve tracing, which enables us to provide a faster, more detailed analysis and maximize output." SOLV recently completed a survey of a utility-scale (200 MWdc plus) installation via drone in less than 6 hours, and the inspection team produced its detailed report in less than a week. Comparable assessment with I-V curve tracing would have required weeks to perform. SOLV's aerial imaging approach resulted in a savings of approximately 50%.

Put Drones to Work for Your Business

Drones put the power of aerial thermal inspections in the hands of EPC firms, O&M technicians and regional drone service providers. They can minimize or eliminate the need for ground site inspections with handheld I-V curve tracers and other analytics tools, improving overall worker safety while lowering O&M cost. Some of the largest national insurance companies, such as State Farm and Travelers, also now use drones for rooftop inspections.

Drones offer some powerful features, such as tunable deliverables. For instance, an EPC firm may opt to obtain an extremely high-resolution dataset on areas of interest, such as a defective subarray for warranty prosecution, or a site-level overview. These tunable variables create flexibility in the type and means of data collection. The rapid growth of the commercial drone sector has fostered the creation of automated, industry-specific software with flexible outputs including paper reports and backend system integration. As a result, aerial inspections typically streamline reporting turnaround time, in some cases allowing preparation of comprehensive reports in a single day.

Aerial inspections complement on-site data collection systems and their cloud-based monitoring counterparts. Asset-monitoring solutions that utilize on-site hardware provide monitoring with a high temporal resolution (the precision of a measurement with respect to time) or constant measurement. These solutions also typically monitor energy and environmental data to optimize asset performance. Drones complement these systems with high spatial resolution that can localize issues to the cell level and also detect possible site-level issues such as vegetation growth or excessive soiling. Monitoring solutions can guide plant operators to determine when and where to send a drone within a PV system.

Keith Aubin, geographic information system manager at Enel Green Power North America, used drones to inspect over 70 MWdc of capacity across nine power plants in 2017. In 2018, he is working to spread this technology to Enel Green Power's O&M teams around the world. "As we standardize our process for localizing string and module-level defects, we expect to save significantly on the labor cost to manually identify, log and correct issues."

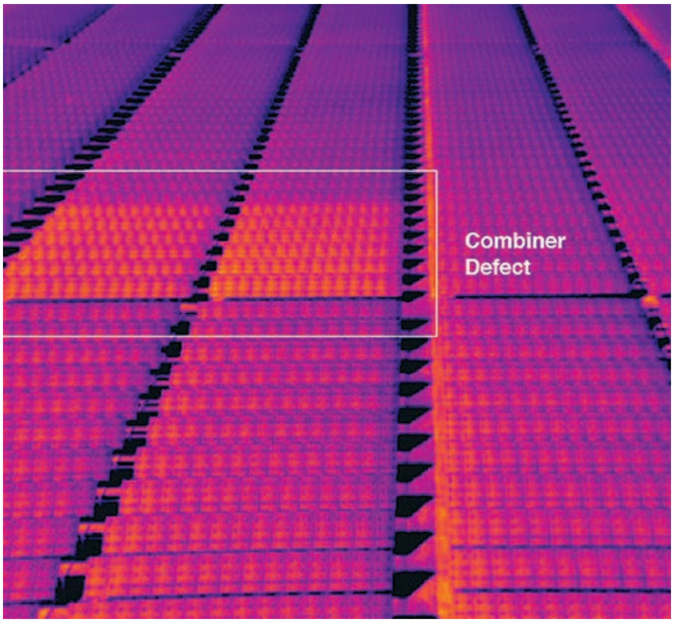
Drones make aerial thermography accessible for commercial and industrial (C&I) solar projects by improving site access to these installations. The fixed cost to deploy a manned aircraft can easily outweigh the benefits for C&I sites. A technician with a drone in his or her vehicle, in contrast, can quickly deploy it during a site visit, completing data capture in minutes. C&I sites tend to be located in more densely populated areas, making it easy to source qualified drone service providers.

Worker safety is another important consideration in favor of using drones to perform inspections. PV arrays in C&I installations are often located on facility rooftops or carports that expose workers to fall hazards. Technicians that perform system inspections on rooftops require special fall protection training and equipment.

What Can Drones Detect?

Aerial thermography provides site-wide coverage for utility-scale and C&I solar installations. According to Randall Warnas, segment leader for global small unmanned aerial systems (sUASs) at FLIR, the world's largest IR camera manufacturer, "Handheld thermal cameras are an industry standard for inspecting PV systems, and drones put that technology in the air. By the numbers, solar has been one of the top applications for thermal drones, second only to law enforcement and emergency services."

In PV applications, drones equipped with infrared and visible RGB cameras can detect module-specific issues such as activated bypass diodes, production batch issues, junction box heating, and cell and multicell defects including cracking. Technicians can also use aerial thermography to identify and document electrical equipment and system-scale issues such as PV array source-circuit failures, reversed polarity, and array combiner box and inverter failures. Aerial site inspections can identify site issues such as shading from new vegetative growth, excessive soiling, tracker failure and security breaches.



Courtesy SOLV

Thermal imaging A combiner defect sent 48 PV strings off-line. SOLV, Swinerton Renewable Energy's O&M division, detected the failure using drone-based aerial thermography.

Drone inspections can generate hundreds or thousands of images per site. However, the consistent geometry of PV systems allows for the separation of modules and the use of artificial intelligence to diagnose module defects, while simultaneously assessing and comparing the hierarchy of subsystems such as module versus module or string versus string.

Make Drone Data Actionable

To optimize time savings, you should match drone data capture to the specific management goal, such as identification of off-line PV source circuits or module-level cell defects. No matter how much drone data you collect, proper PV system analytics deliverables should provide four primary components:

A high-level overview. Data should enable a technician to prioritize repairs in a limited time window. Deliverables should specifically call out, in an executive summary, large defects, such as an inverter or combiner failure, and their impact on the plant's overall capacity and production. This summary allows supervisors to triage sites under their management.

Granularity. Results should associate every identified defect with an image, location, classification and affected dc system capacity; give summary statistics for each subarray or array; and allow you to filter results by location and defect category. Technicians can refer back to these results when tracking site conditions over time.

Location. Inspection analytics deliverables should provide defect locations using a localized coordinate system, such as subarray, row, string and module number, as well as GPS locations. GPS identifiers help analysts visualize the distribution of issues, while localized coordinates are more useful for field technicians replacing modules. You can base localized coordinates on a geographic location, such as the number of rows north, or on the asset designations in the as-built drawings.

Compatible results. Finally, analysis and report deliverables should come in an open format, such as a spreadsheet or KML file, that the client can easily import into a variety of software systems. As drone-based thermography, analysis and reporting technology become more widely deployed, that sets the stage for an open data standard that allows asset owners and O&M companies to track site progression regardless of who collected the data. Given the multitude of solar monitoring and aggregation software platforms, an open data standard will also make it possible to reduce software integration complexity.

Camera and Image Considerations

Thermal imaging drones previously required aftermarket integration, but turnkey systems with high-quality cameras are now commonplace.

Camera types. There are three main considerations when deciding which thermal camera package to purchase with your drone: resolution, radiometry and lens size.

Thermal cameras for drones are typically available in two resolutions: 640 by 512 pixels and 336 by 256 pixels. The higher resolution will cover a footprint four times larger in area than the lower resolution, resulting in a significant time savings when inspecting a PV system.

Many cameras are available in both nonradiometric and radiometric versions. Radiometric cameras are more accurate, typically within 2°F–4°F. Most important, radiometric cameras have infrared measurements in each pixel, required for automated analysis. The camera you select should output radiometric JPEG or thermal TIFF files.

Drone thermal cameras are available with a variety of lenses, from 7 mm to 25 mm and beyond. A 7 mm lens causes fisheye effect, while a 25 mm lens has an extremely narrow field of view. For PV system inspection, 13 mm lenses tend to be the most versatile.

Raptor Maps makes software to analyze drone data and report findings. It applies machine learning and artificial intelligence to automate the processing of thermal infrared and color images. To date, its software has processed data from more than 5 million modules, in sites ranging from small rooftop systems in Europe and the Northeast US to utility-scale plants in the Southwest US. Based on the data from these millions of inspected modules, we recommend the following camera type for drone-based solar site inspections: A 640-pixel resolution, radiometric camera with a 13 mm lens consistently produces high-quality input data.

Color images. Color photos are an important complement to thermal imaging. Software can overlap RGB

Courtesy Raptor Maps

Flight planning Drone operators can tune the resolution of thermal scans by varying flight altitude. While high-altitude flights result in a faster survey, low-altitude flights provide more detail regarding defects.

color drone images to create large high-resolution site maps. This is particularly useful for older sites that may not have accessible as-built drawings or for newer sites that may not have updated high-resolution aerial or satellite imagery in services such as Google Maps.

Flying a drone at 400 feet with an RGB camera to make a map can take as little as 10 minutes on a 20 MW site. Color images also help software identify the root cause of issues at the module level. For example, soiling and cracking issues may appear similar in a thermal image, but a color image enables you to easily distinguish them.

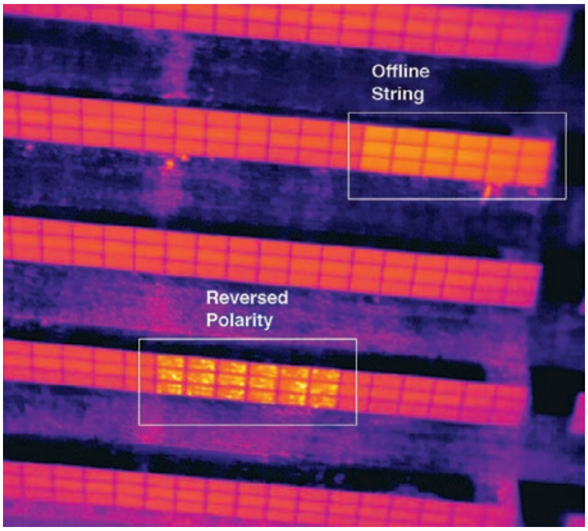
Plan Your Data Capture

Whether you are considering drone training or have been authorized to fly an sUAS, the following best practices will help you do so safely and capture high-quality thermal images and color photographs for solar installation inspections.

Check the airspace. Part 107 of the Federal Aviation Regulations authorizes sUAS pilots to fly up to 400 feet in uncontrolled airspace. For flights in controlled airspace, such as those in proximity to airports, the Federal Aviation Administration (FAA) has published online maps to aid in the waiver process. When applying for a waiver, allow yourself up to 90 days to complete the application, and remember that submitting an airspace authorization does not obligate you to fly. The FAA is also beta-testing the new industry-developed Low Altitude Authorization and Notification Capability (LAANC) application, which allows real-time processing of airspace notifications and automatic approval of requests. SunPower was the first solar company to utilize LAANC, in October 2017.

Plan a flight pattern. You can plan the entire flight with a few taps on your electronic device. Flight planning apps, also known as ground station apps, allow you to box the boundaries of the PV system you are going to survey and automatically create a lawnmower pattern for complete coverage. You can fly the drone manually if you are inspecting for a specific issue, such as a combiner box failure that is impacting multiple strings. However, capturing the complete site is typically recommended, because there are many issues you cannot simply detect on the tablet's screen—they require analysis. Additionally, the tracking of features helps software-based analytics solutions measure motion and automatically localize defects. Generally, you need high overlap in the direction of flight and low overlap between passes. Choose a non-oblique direction, either parallel or perpendicular.

Plan altitude and heading. Drones give you the ability to tune the resolution to achieve your desired granularity. Checking for functional module strings during commissioning may require a high-altitude survey, while a warranty claim for a batch of modules with defective cells may require low-altitude flights that result in a higher resolution. As an example, the recommended camera setup flying at 130 feet above the array will spot a 6-inch defect in a given module, while the same setup flying at 30 feet will spot a 1.5-inch defect.



Courtesy Raptor Maps

Failure modes Thermal infrared imaging can help determine different types of common failures in PV systems, such as off-line strings and dc source circuits with reversed polarity.

Follow safety procedures. Routine on-site practices already incorporate many of the safety considerations for drone flights. These include awareness of surrounding hazards, knowledge of who is on the job site and a strong safety culture. Recommended personal protective equipment for drone operators includes helmets, sunglasses and safety vests.

Fly in good conditions. Sunny days with calm winds are the best time to fly your drone. The National Renewable Energy Laboratory recommends an irradiance of 600 W/m^2, so pay extra attention when flying at high latitudes in the winter during low-irradiance conditions. Also keep in mind that calmer wind conditions make it easier to keep your drone on course and preserve its battery life.

Avoid glare. Glare is the reflection of sunlight into the camera, which results in false readings. Software for automated defect identification and localization can tolerate a gimbal tilt by up to 20° off nadir to avoid glare. Set the drone to maintain its heading so that it does not turn around with every pass. This keeps the camera angle consistent relative to the tilt of the modules.

Avoid motion blur. While it may be tempting to set the drone to the maximum speed, this can result in blurry images. If you want to survey the PV system faster, increase the flight altitude instead.

Check data quality. Check your data before leaving the field to ensure that it is free from glare and motion blur, contains files in the correct format and covers your entire flight. Finally, always take the time to back up the memory card. This simple and often overlooked step can make the difference between completing an aerial solar asset survey successfully and having to spend time and money repeating it.

Drone Operator Trends

In 2016, the FAA updated Part 107 of the Federal Aviation Regulations, which covers the use of commercial drones, and removed major roadblocks to the commercial operation of drones. Operators are no longer required to hold a traditional pilot's license. Instead, they must pass a written aeronautical knowledge test at an FAA-approved testing center, pass a TSA background check and be at least 16 years old to qualify for a remote pilot certificate.

In the 18 months since enactment of these new regulations, the FAA has authorized more than 100,000 remote pilots to fly an sUAS in the US. Several drone schools with weekend courses train new operators. This has made it easier for solar professionals to train their technicians to use drones and to find qualified regional drone service providers. The quick pace of advancement and the rapid maturation of the drone industry make leveraging its technology for PV system O&M activities increasingly applicable to both large and midsize solar EPC firms and integration companies.

—Nikhil Vadhavkar / Raptor Maps / Boston, MA / raptormaps.com

Introducing the New ME-ARTR Advanced Router

The ME-ARTR Advanced Router from Sensata Technologies is designed to connect large, residential Magnum Energy solar + storage installations. The Advanced Router provides complete system-level connectivity and programming for up to 42kW harvest, as well as:

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Sensata Technologies

PV Commissioning Tips and Best

By Nate Goodell, David Tedeyan and Gordon Woodcock

Whether you measure your project size in kilowatts or megawatts, understanding the key concepts and processes for commissioning PV systems increases your bottom line and your clients' satisfaction.


Courtesy Taitem Engineering

When done correctly, PV system-commissioning activities ensure customer satisfaction, project safety and longevity, while adding very little in terms of time and cost. Commissioning agents can prove that a system is working as promised, set performance baselines and verify that it is properly documented. In return, this modest investment greatly facilitates future operations and maintenance activities.

Here we provide an overview of key precommissioning activities based on our experiences as a certified commissioning agent. We then share some post-construction commissioning tips to help you avoid common issues. These concepts and procedures will leave you better prepared, regardless of whether your projects are subject to in-house acceptance and sign-off tests or independent inspections by third-party commissioning agents.

What Is Commissioning?

Many incentive programs, certification entities and installation manuals use the term *commissioning* generically to describe a set of start-up or closeout procedures. In this informal context, a system installer might verify field connections and ac and dc voltage levels before "commissioning" an inverter. Qualified persons adhere to similar start-up procedures before energizing any electrical component. While these steps are essential for electrical safety, they do not guarantee system performance or verify as-built conditions.

Practices

In this article, we define commissioning more formally as a standardized and unbiased process that not only guarantees the safe operation of a PV system, but also confirms, via independent verification activities, that its documentation is correct and that it is performing as expected. Commissioning agents use a variety of testing and inspection techniques to proactively identify and address issues that affect plant production, operations, maintenance or safety. These formal commissioning activities not only promote compliance with codes and engineered plans, but also help ensure that PV systems will meet energy production estimates.

In some cases, solar installation companies implement common commissioning tests as part of an in-house safety or quality control program. While this is an admirable best practice, an internal company review is not necessarily unbiased from the perspective of the system owner. This is why contract terms for some projects specify that project deliverables must include a third-party commissioning report. Every project pursuing LEED certification is subject to independent commissioning and verification requirements. Many financial backers of large PV systems require independent third-party commissioning to validate their investment.

The commissioning agents responsible for generating this third-party report represent the system owner rather than the installer. These agents build on the installer's start-up procedures by performing spot checks and specialized operational tests, evaluating build quality as well as system efficiency and functionality. They document all their findings and recommendations and report these directly to the system owner.

Shawn Schreiner

Inspection checklist Construction inspection checklists are an essential commissioning tool. If your company inspects a variety of project types, consider developing flexible templates that you can customize on a per-project basis.

PRECONSTRUCTION

The commissioning process begins during project planning, before construction has even started. Based on the project design documents, you want to prepare or customize a construction inspection checklist, analyze job hazards and develop a commissioning plan that reflects test priorities. All of these activities presume that you already have access to some basic yet flexible data forms and templates, as well as a library documenting common test procedures. These organizational resources are an important and often overlooked aspect of successful commissioning. To optimize workflow on-site and back in the office, companies need to have a process in place for identifying and recording abnormalities that is accurate and easy for others to follow, which requires some advanced planning.

Prepare checklists. Commissioning agents use construction inspection checklists to identify common defects and *Code* issues, to initiate and track the status of repairs, to meet compliance requirements, and to ensure and document that a project is ready for functional testing.

It helps to have the end user in mind when you prepare checklists. Try to organize them logically based on the workflow in the field. Strive to capture all relevant information. However, avoid making checklists and test forms so complicated that technicians spend more time filling out documents than inspecting and testing the system. Reserve room for personnel to make notes in the field. The goal is to create practical and usable documents.

Weigh the benefits of using digital versus paper forms. On the one hand, digital files and data are easy to share; on the other, printed checklists never run out of batteries. A paper checklist that gets left out in a rainstorm is also less expensive to replace than a tablet or laptop. Often the best solution to field documentation is a hybrid approach. Take a set of hard-copy forms into the field and enter data by hand. At the conclusion of each component CONTINUED ON PAGE 22

test, photograph the completed forms so that you have a digital backup. If you use your cell phone as a camera, you can directly convert each page to a PDF with a scanner app.

A construction inspection checklist may include any of the following issues: unsupported or improperly bonded conduit; reversed conductor polarities; open homeruns; incorrectly torqued module clamps, attachments and terminals; improperly seated or terminated conductors; unsealed conduit or enclosure penetrations; grounding deficiencies; missing labels or system information; and discrepancies between the engineering drawings and the as-built conditions. Consider sharing these checklists with the project manager or site supervisor. The better they understand your pass-fail criteria, the fewer issues you should find.

Analyze hazards. Like any other employer, commissioning service providers need to systematically assess and address job hazards and develop clearly defined and documented safety procedures. Commissioning technicians face many of the same job hazards as installers, and some commissioning activities may even carry a greater degree of risk. To perform operational tests, for example, technicians must have the PV system up and running, which exposes them to lethal shock and arc-flash hazards. Commissioning tests intentionally simulate all possible operating conditions. To test safety devices, technicians must even simulate faults and failure modes that could result in unintended consequences or equipment damage.

To comply with OSHA requirements, companies need to not only document safe working practices, but also train and supervise workers to ensure that they follow these practices. When developing a safety plan, consider every testing procedure with an eye toward unwanted results. By considering these hazards in advance, you can ensure that workers in the field have access to the appropriate personal protective equipment (PPE) and training.

While a comprehensive discussion of safe work practices is beyond the scope of this article, commissioning personnel need to keep a few safety issues at the forefront of their minds:

- Identify all sources of power before opening any panel or enclosure.
- Always utilize lockout and tagout procedures to prevent others from accidentally energizing components that you are testing.
- Never assume that no voltage or current is present in a conductor unless you test it yourself, even if you just opened a disconnect.

Courtesy Solmetric

Visual inspection Many commissioning activities do not require specialized equipment, but rather a thorough understanding of the engineering plans, applicable codes and industry best practices.

To work safely, every commissioning technician needs at a minimum to have a digital multimeter with an amp clamp that can read both ac and dc current, electrically insulated screwdrivers and gloves, and safety glasses or a face shield. These PPE requirements get more stringent as operating voltages and arc-flash hazards increase.

Develop a test plan. Visual inspections as well as performance and operational tests are an important part of the commissioning process. The extent of these tests will depend on the size and scope of the project. As project scale increases, it becomes impractical to visually inspect or physically test every system subcomponent. So what and how many components will you inspect or test?

When developing a functional test plan, you need to balance testing costs against the potential financial benefits associated with avoided problems. Many installers understand this balance intuitively. On the one hand, it is a function of risk and probability: What are the worst-case consequences of a component failure and how common is that failure? On the other, it is a function of expedience: How easily or quickly can you run the test?

A good commissioning test plan produces maximum effect with minimum effort. Large systems often necessitate sampling, in which agents test a representative set of units (source circuits, combiner boxes, fuses, disconnects and so forth) rather than all units. If multiple units within a randomly selected sample fail in the same way, you may have identified a recurring problem. In this case, you should expand the sample size. When examining these additional units, it is not necessary to run the whole battery of tests—just check for signs of a systemic issue.

Commissioning like a Pro

Looking for more information about commissioning activities and tools? We got you covered. For a deep dive into a variety of commissioning-related topics, check out these articles from the *SolarPro* archives:

"PV System Commissioning" by Blake Gleason, October/November 2009

"Implementing a Successful Safety Program" by Karl Riedlinger, October/November 2011

"Data Acquisition System Installation and Commissioning" by Adam Burstein and Josh Haney, April/May 2013

"Commissioning and O&M Tools" by Brian Mehalic and David Brearley, February/March 2014

"Calculating DC Arc-Flash Hazards in PV Systems" by Finley Shapiro and Brian Radibratovic, February/March 2014

"Winter Commissioning" by Michael Vance, April/May 2014

"Interpreting I-V Curve Deviations" by Paul Hernday, August/September 2014

POST-CONSTRUCTION

By the time the project is ready for testing, you should have confirmed the commissioning test deliverables, completed installation checklists and prepared the test plan. Except in cases of recommissioning or retro commissioning, most PV system commissioning activities take place after installation is complete but prior to project closeout. In this scenario, the commissioning team is responsible for ensuring that the fielded project meets the owner's requirements before the owner takes control.

In an earlier *SolarPro* article (see "Commissioning like a Pro" for more details), Blake Gleason describes the basic elements of a PV system commissioning as follows:

- Verify that the installation is complete.
- Verify that the installation is safe.
- Verify that the installation is aesthetically acceptable.
- Verify that the installation is robust and permanent.
- Document as-built conditions.
- Verify system performance and proper operation.
- Complete required acceptance documentation.

Since Gleason elaborates on these steps, we will not specifically consider each task here. Instead, we will share some tips for successful commissioning, recommend how and when to perform critical tests, and discuss some specialized tools that commissioning agents use. Larger commercial and industrial-size systems, for example, require additional assurance beyond using checklists and testing voltage and current, which is where you will need more-advanced tools such as infrared (IR) cameras and I-V curve tracers.

Allocate resources wisely. When implementing the test plan, consider how you will allocate resources and look for opportunities to streamline the workflow to improve operational efficiencies. Some tests are a one-person job, meaning that multiple people can perform these tasks at various locations in the system. Other tests are better suited to a tag-team approach, meaning they are most efficient when two or more people work together. Some tests, for example, require that technicians take readings at multiple locations simultaneously. In this scenario, it is best to designate one person as the lead documenter. Both technicians can still take notes, but one person is specifically responsible for ensuring that all tests are completed and documented properly.

All else being equal, we recommend a workflow that starts with independent testing activities designed to identify the most obvious potential issues and then transitions to simultaneous testing activities after team members establish a rhythm. Testing location is another consideration. Teams can lose a lot of time when they have to travel from a rooftop array down to a basement panelboard and back to the roof again.

Look for opportunities to minimize downtime by optimizing test activities around specific locations.

Know your targets. To avoid unnecessary callback visits, commissioning technicians need to verify that performance test data are within expected ranges. If the measured data do not make sense based on the anticipated results, it is important to determine whether something went wrong during the test process or whether something is wrong with the system. It is much easier to determine the root cause of an unexpected measurement in the field than back in the office.

When gathering performance test data in the field, make sure that you are documenting all of the requisite information. If you find outliers or suspect values in the data, verify that the measurement is representative of the system and not a problem with the testing tools or methods. If an I-V curve looks strange, run another trace. If string voltage measurements do not make sense, make sure that the multimeter is not accidentally set to measure ac voltage.

In most cases, a quick investigation will turn up the cause of an erroneous or out-of-range measurement. If the problem is indeed an installation error, do your best to identify the nature of the problem in the commissioning notes. For example, you can add a lot of value to a commissioning report by noting that someone misidentified and incorrectly terminated a pair of conductors rather than simply reporting that you did not measure any voltage on strings 1 and 2.

Verify performance. The simplest performance verification tests start with the nameplate power rating of the system and calculate the effects of real-world irradiance and temperature measurements, as well as the estimated system-level efficiency. The aforementioned Gleason article outlines a five-step performance verification process that calculates expected power (P_E) based on the following equation:

$$P_E = P_{STC} \times K_I \times K_T \times K_S$$

where P_{STC} is the nameplate rating of the array under standard test conditions, K_I is the irradiance factor, K_T is the module cell temperature factor and K_S is a system derating factor.

It is not difficult to calculate the irradiance, temperature and system derate factors. To find K_I, simply divide the measured irradiance by the irradiance at STC (1,000 W/m^2). To estimate K_S, multiply system-level efficiencies together to account for power tolerance, soiling losses, age of system, inverter efficiency, and ac and dc wiring losses. The calculation for K_T is slightly more involved:

$$K_T = 1 + (C_T \times (T_C - T_{STC}))$$

Shawn Schreiner

Performance verification In addition to collecting performance verification data, commissioning agents should verify that the measured results make sense based on predicted values. Spreadsheets are a good way to expedite this process and eliminate the need for avoidable callbacks.

where C_T is the module temperature coefficient, T_C is the measured cell temperature and T_{STC} is the cell temperature under STC conditions (25°C).

The SunSpec Alliance's best practices guide, "Commissioning for PV Performance" (see Resources), details an initial commissioning-capacity test method, known as the *power temperature coefficient model,* similar to Gleason's method. To evaluate inverter- or system-level performance in this fashion, technicians require accurate plane-of-array and module temperature measurements. Teamwork is helpful and sometimes required to capture these measurements simultaneously with a power-output reading.

While these types of instantaneous performance tests are relatively straightforward to execute and reasonably accurate, the process does require concentration and attention to detail. Rather than running numbers while taking measurements on the roof, have a partner sit down with a pencil and calculator. If you use a spreadsheet to automate the process, technicians simply have to enter field measurements instead of performing calculations manually.

Measure voltage. PV system commissioning is not necessarily a one-size-fits-all endeavor. When commissioning a residential project with a multi-MPPT string inverter, you may be able to verify proper system operation—or at least rule out major issues—simply by scrolling through the inverter's display screen. What are the Vmp values for each string? Do these values make sense based on the ambient conditions and the number of modules per source circuit? If inverter-output power also checks out, this quick-and-dirty performance analysis may be adequate as a system execution test within the context of LEED commissioning and verification activities.

A more common and reliable commissioning practice is to independently measure the Voc of each string. By isolating each string, you can tell whether a source circuit has the correct polarity and the proper number of modules in series. With consistent test conditions, a spreadsheet and an accurate multimeter, you can even identify module-level issues such as a failed bypass diode. When checking voltage in an inverter with multiple strings on a common bus, it is important to isolate each source circuit. In a larger inverter, you can usually open and close fuseholders under no-load conditions to take these measurements. Where two or three strings are paralleled without series fusing, as is often the case on multi-MPPT string inverters, you may need a tool to isolate individual source-circuit conductors.

Courtesy Taitem Engineering

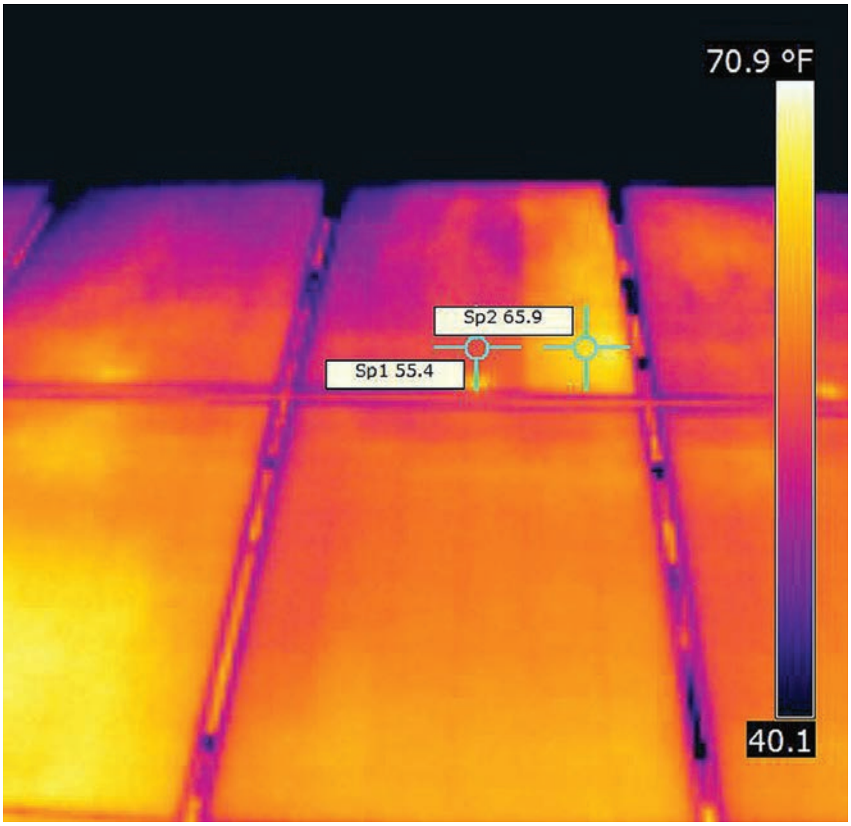
Check for current first Whenever PV source circuits are paralleled on a common bus—like the four-circuit groupings shown here—technicians need to use a dc clamp meter to test for current *before* opening fuseholders to take voltage measurements. Opening a circuit with current flowing in it can pull an arc capable of damaging equipment or starting a fire.

When isolating source circuits in inverters or combiner boxes, it is important to use a dc clamp meter to check for current before opening any fuseholders or lifting any wires. If a voltage mismatch exists between strings paralleled at a common busbar or MPPT channel—perhaps due to an installation error or equipment issues—then the higher-voltage strings can dump current into the lower-voltage string even if the dc disconnect is turned off. While the 15 A or 20 A string fusing prevents module damage, opening a circuit with current flowing in it can pull an arc capable of damaging equipment or starting a fire.

Check for ground faults. To check for ground faults while taking Voc measurements, simply measure the voltage to ground from both the PV positive lead and the PV negative lead. Unless one of the poles of the array is intentionally connected to ground, the expected voltage reading is 0 Vdc, so it is easy to tell if a string has a ground fault.

The exception occurs where PV systems are deployed with rapid-shutdown boxes. This practice is most common in string inverter systems subject to the array-level rapid-shutdown requirements that first appeared in *NEC 2014*. Because the rapid-shutdown box will skew ground-fault measurements, you need to lift the strings from the box to accurately measure voltage to ground. Fortunately, it is seldom necessary to test individual strings for ground faults in this scenario, as the inverter itself is equipped with advanced ground-fault detection technology.

Perform IR thermography. Thermal scans performed with an IR camera are useful for identifying a variety of common issues within the array—including cracked cells, hot spots, defective diodes, failed modules and nonoperational strings—as well as high-resistance electrical connections and thermally stressed overcurrent-protection devices. One advantage of a walk-through thermal scan is that a secondary visual inspection happens by default. If an IR scan produces an odd or unexpected thermal signature, technicians can take a closer look to identify any obvious issues or causes.



Courtesy Taitem Engineering

Thermography training Technicians need specialty training to use IR cameras properly. Certification classes are a good way to learn how to adjust the camera's temperature range to spot issues, such as this bad bypass diode, without generating false positives.

When doing thermal scans, you must have the right equipment and know how to use it. PV inspections are most effective performed with an IR camera operating within a specific thermal sensitivity range. An IR camera's thermal sensitivity is a function of its noise equivalent temperature difference (NETD) rating, expressed in milli-Kelvin (mK). While the IR camera manufacturer FLIR recommends an NETD rating of less than 80 mK for testing fielded PV systems, our experience is that a 100 mK camera works just fine. It is not necessary to have an IR camera with a high pixel count and high image resolution, but these features can speed up the scanning process by letting you capture images farther from the array.

Before adding an IR camera to your test kit, you need to get training and do some test runs. Since IR cameras pick up reflections in glass such as the front of a solar module, they are sensitive to false positives. In some cases, it is helpful to take an IR scan of the back of a module to correct for this. You also need to make sure you have set the camera's temperature range properly based on the operating temperature of the component you are testing. There is a science behind interpreting IR images to determine acceptable variations between readings, identify problematic outliers or understand how environmental factors play a role. While an IR camera is a powerful tool for the commissioning toolkit, it is not one for beginners.

Employ I-V curve tracers. I-V curve tracers effectively capture all the current- and voltage-operating points for a PV source in a single test, measuring Isc, Voc and enough intermediary operating points for software to identify Vmp, the knee of the curve. The same software can automatically compare the actual I-V curve to the expected one based on module STC ratings and instantaneous temperature and irradiance measurements. As a diagnostic tool, curve tracers can verify proper performance and identify common issues such as bypass diode failures, bad connections, soiling or module degradation.

Different curve tracers on the market suit different project needs. Commissioning technicians frequently use the Seaward PV210 and the Solmetric PV Analyser (PVA) models in the field. Seaward's curve tracer is a handheld device that can do all the commissioning tests to meet IEC 62446 standards with a single button push. Running the test suite takes about 30–40 seconds, and the device stores 999 tests.

While the display screen provides only basic information, the accompanying Android app can show the full trace. The small form factor of the Seaward PV210 is very useful for running tests on a pitched rooftop, as is often the case in residential or small commercial applications.

In comparison, the Solmetric PVA requires a laptop to run tests. Depending on the situation, this can be advantageous or not. On the one hand, a laptop is one more thing to set up and manage on a rooftop. To capture an insulation resistance measurement as specified in the IEC 62446 standard, technicians need yet another tool. On the other, the Solmetric PVA software can create an inverter tree and save each curve trace to the proper location in real time. On systems over 500 kW, this greatly speeds documentation since you do not have to manually identify every string later. The Solmetric PVA can also do a curve trace in about 3 seconds and display it on the computer screen, allowing the user to immediately evaluate the curve. When you are working on systems with hundreds or thousands of strings, this can save hours or even days on-site.

Depending on project location and time of year, weather conditions may not be ideal to use curve tracers for formal performance verification activities. Consistent high-irradiance conditions are required to capture accurate data. For example, Solmetric recommends a minimum irradiance of 600 W/m^2 and Seaward recommends at least 700 W/m^2. In winter, there are few opportunities to meet these criteria in many parts of the country. Temperature can also be a consideration, as the Seaward curve tracer will not operate properly if the module temperature or ambient temperature drop below freezing.

When you are dealing with marginal weather conditions, it is important to consider your test goals. Some commissioning contracts specify that you conduct formal performance verification tests under optimal test conditions, so you may have to wait until the weather improves before capturing curve traces and IR images of the array. If requirements are less stringent, you can identify many of the most significant performance issues under suboptimal conditions. Just bear in mind that some issues will not show up without enough current flowing through the modules. In addition, the accuracy of your results suffers under suboptimal test conditions, meaning these data are not as useful for performance verification purposes.

Protect your data. When relying on electronic testing tools, it is important to consider worst-case scenarios and plan for every eventuality. For example, save data early and often; carry a spare set of fused test leads; bring chargers, backup batteries and data cards; take more photos than you think you need; and write down initiation times for each test.

Photos and electronic records are usually time-stamped, but these data are correct only if you properly initialized the device. Write down test initiation times and you can subsequently verify test sequence or correlate results to weather conditions and so forth. You can also use these data to measure productivity in the field, which will help you improve planning and budgeting activities for the next project.

Use remote performance monitoring. Technology trends provide an increasing number of opportunities for remote performance verification. Consider a PV system deployed with module-level power electronics and monitoring. In this scenario, it is easy to tell if something is not working, or is working at a reduced capacity, by comparing the instantaneous power output and cumulative energy production for each device over a period of time. This trend toward granular monitoring is also evident in large-scale applications, where some multi-MPPT string inverters provide string-level performance data, including remote I-V curve traces.

Even basic production monitoring allows you to infer a lot about the operational performance of an array. By reviewing trend data or skimming large data sets, you may be able to identify small deviations indicative of a meaningful issue. It may not be possible to spot a single underperforming module, but you might spot the aggregated effects of two or three underperforming modules in the monitoring data under specific operating conditions. With a quality production estimate, you can see how close actual production matches predicted output and pinpoint deviations by comparing results to similar systems.

Track and resolve issues. As the owner's agent, it is your job to ensure that responsible parties resolve any items that fail inspection prior to project closeout. You need to have a process in place to report issues to the appropriate parties and track the status of these issues. For larger systems, you may want to develop a quick reference system to expedite the process of reporting and following up. Depending on the system size and the type of issues, you may have to postpone performance verification tests until after the responsible parties have resolved all open items. Then you can use the performance verification test site visit as an opportunity to verify the completion of corrective actions and visually inspect the workmanship and quality of any rework.

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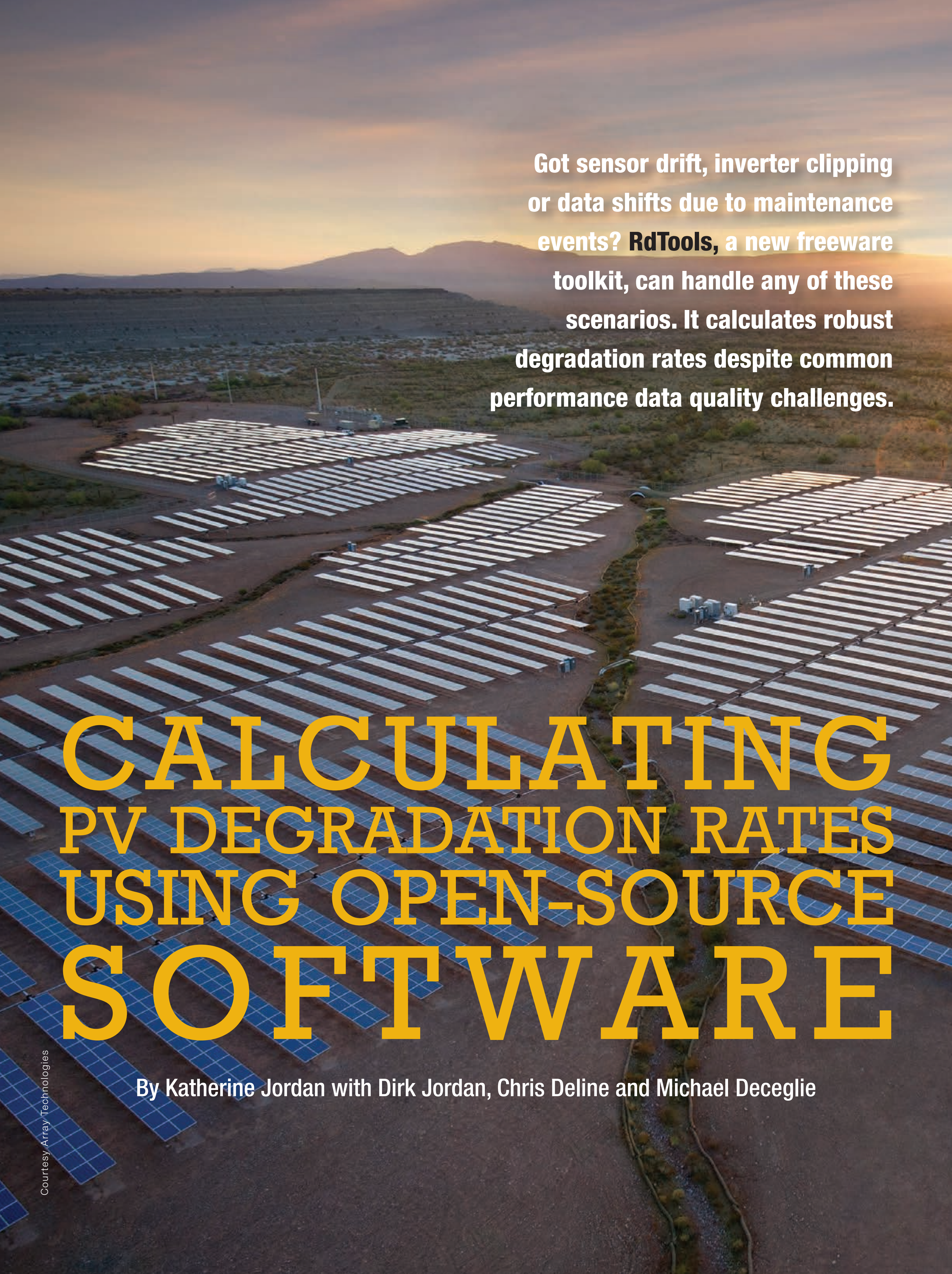
RESOURCES

SunSpec Alliance, "Commissioning for PV Performance: Best Practice Guide," October 2014



Courtesy Array Technologies

Got sensor drift, inverter clipping or data shifts due to maintenance events? RdTools, a new freeware toolkit, can handle any of these scenarios. It calculates robust degradation rates despite common performance data quality challenges.

CALCULATING PV DEGRADATION RATES USING OPEN-SOURCE SOFTWARE

By Katherine Jordan with Dirk Jordan, Chris Deline and Michael Deceglie

The *degradation rate* (R_d) quantifies the rate at which PV systems or modules lose performance over time. R_d values not only drive the results of long-term energy production estimates for financial projections and other studies, but also help provide consumers and investors with an indicator of PV system quality and durability. In conjunction with taking other quality assurance steps, project stakeholders can also use the R_d to guide product selection and determine whether PV products or installations meet warranty terms. Accurate R_d data are therefore essential to the solar industry's long-term success.

Here we provide an introduction to RdTools, a free and publicly available software package intended to help users evaluate R_d more easily and quickly. One of the benefits of this open-source toolkit for calculating degradation rates is that it can accommodate common challenges associated with real-world performance data, including sensor drift, clipped power curves or data shifts due to maintenance events. Since accurate methods for calculating PV degradation rates are important for manufacturers, insurers, engineers, utilities, installers, investors, businesses and consumers alike, many solar industry stakeholders may find RdTools useful.

DEVELOPING RDTOOLS

Like module efficiency, R_d values are expressed as a percentage. However, module efficiency and module degradation rates represent very different values. R_d is relative to a baseline of 100% initial production. As an example, if a 22% efficient module degrades linearly at a rate of -0.6%/year, then its efficiency after 25 years would be 18.9%. In RdTools and in this article, a degradation rate with a negative number indicates a decrease in production.

Scientists and industry experts have long sought ways to consistently calculate accurate PV degradation rates. This is a challenging undertaking for a number of reasons. First of all, to establish a reliable basis of comparison, you must account for performance transients when establishing the 100% performance baseline. PV module performance stabilizes over a period of days or months, depending on cell technology, and it is important to use the post-stabilization value as the starting point for R_d calculations. Depending on the module technology and the project construction schedule, project stakeholders may be able to account for stabilization effects by simply waiting until after the completion of system commissioning activities to establish the 100% performance baseline value.

Additional challenges arise post-commissioning and -stabilization. Since degradation is not necessarily linear, it is necessary to run analyses that tolerate nonlinearity. More important, a number of scenarios can impact the quality of the data used to calculate R_d values. These complicating factors include highly variable weather, data outliers, poorly maintained sensors, seasonal soiling or shading, and data shifts from maintenance events.

To address these challenges, researchers at the National Renewable Energy Laboratory (NREL)—notably Michael Deceglie, Chris Deline, Dirk Jordan and Ambarish Nag—developed RdTools in collaboration with Greg Kimball from SunPower and Adam Shinn from kWh Analytics. In addition to being relatively accurate and easy to use, RdTools provides project stakeholders with a consensus methodology for calculating PV degradation rates in the real world. To estimate the R_d for a PV system with RdTools, users need ambient temperature data, irradiance data from a sensor or reference cell, and 2 or more years' worth of granular (hourly or better) performance data.

The developers not only used Sandia National Laboratories' open-source PVLIB modeling software (see Resources), but also turned to Python, a freely available scientific computing language, to write RdTools. Users can run RdTools on any computer that has the open-source Python programming language installed. Interested parties can access, download and customize RdTools via the software development platform GitHub (github.com/nrel/rdtools).

HOW IT WORKS

To get started with RdTools, users first enter system configuration details such as longitude, latitude, time zone and PV system mounting configuration. Although RdTools does require some source of on-site irradiance data, on-site temperature measurements are not essential as the software can model these values. Upon start-up, RdTools automatically conducts a prescreening step to check the granularity of the collected data. At present, RdTools is set up to use high-frequency performance data such as 1-minute, 15-minute or hourly values.

Two different analysis methods are available on RdTools. The *sensor-based* method is best if high-quality temperature and irradiance data are available, which assumes that technicians regularly clean and calibrate the project's sensors and reference cells. The *clear-sky* method, which normalizes the data based on clear-sky conditions, is best if sensors have low accuracy or in cases where low-accuracy satellite measurements are the source of the data. The clear-sky method still currently requires some source of irradiance data to identify times of sunny conditions, but it does not demand perfectly cleaned or calibrated sensors.

As detailed below, RdTools follows a four-step data analysis process: First, it normalizes the data, adjusting performance relative to irradiance and temperature; second, it filters the data; third, it aggregates the data and generates periodic totals; and lastly, it calculates the median rate of degradation.

Step 1: Data normalization. In this step, RdTools divides measured production data by modeled ideal values to calculate performance ratio (PR) values. The software derives the modeled values based on meteorological and system configuration details by passing these data into a PVLIB performance model. Currently, RdTools uses PVWatts as the default PVLIB performance model.

There are two possible workflows in the data normalization step. The sensor-based method passes site-measured irradiance and temperature data directly into the PVLIB performance model, in which case the calculations may incorrectly attribute sensor errors to system degradation. Alternatively, the clear-sky method calculates PR values by normalizing site data against modeled clear-sky irradiance and long-term monthly site temperature averages, which produces results that are relatively insensitive to drifting or erroneous ground-based sensors.

Step 2: Data filtering. This step filters data to remove problematic points, including power-curve clipping from a high dc-to-ac ratio, low and anomalous high-irradiance values, and improbable temperature measurements. For the clear-sky method, the software also filters data points based on the clear-sky index to specifically consider sunny conditions.

Step 3: Data aggregation. In this step, the analysis averages the filtered and irradiance-weighted PR data over the aggregation period. This results in a single PR value per aggregation period, which is typically daily.

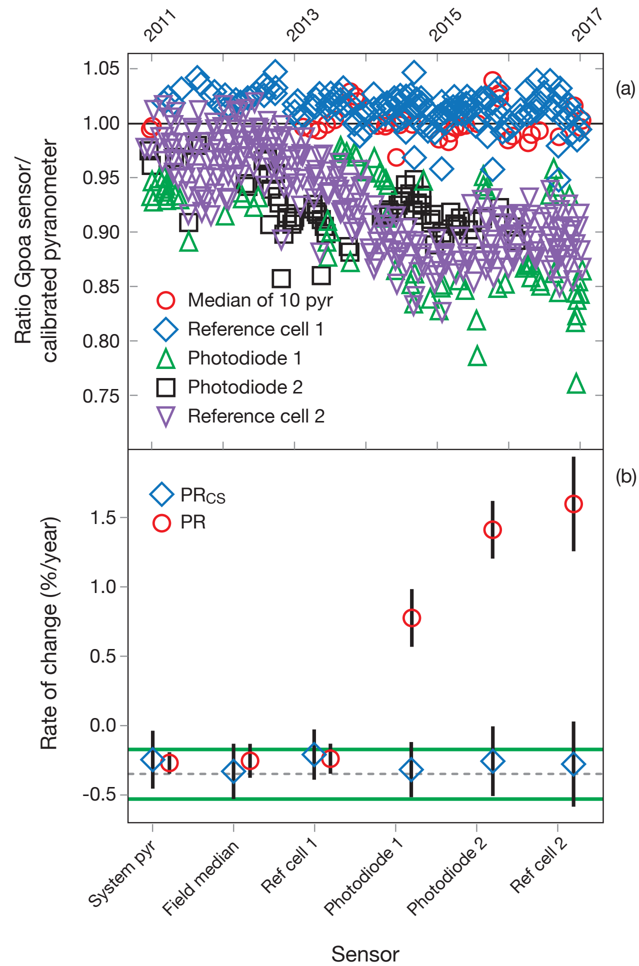
Step 4: R_d calculation. RdTools utilizes a year-on-year (YOY) method of analysis to calculate degradation rates. In this step, the software calculates a series of slopes between any two daily values that are separated by 365 days. This means that if there are 3 years of production data, the software will calculate 730 annual slopes. In the event that there are no data for a particular day—due to data filtering or an outage—the software will not calculate slopes to or from that date. Once RdTools has calculated all the annual slopes, it generates a histogram based on the combined data and reports the median value as the system's rate of degradation.

Customization. One of the best features of RdTools is that users are free to customize the software to fit their needs. Users with some knowledge of the Python programming language can customize aspects of RdTools to better match system and data characteristics. For example, while the default data aggregation period is daily, users can easily change this to a weekly period. Customizability provides users with the ability to optimize RdTools on a per-project basis. Users can adjust data filtering parameters to account for climates that are more or less cloudy than normal or to account for inverter power limiting in systems with a high dc-to-ac ratio. Users can also customize PVLIB system performance models based on specific system configuration details. Due to the open-source nature of RdTools, software developers can communicate with one another, report bugs, review code and propose new functionality via the GitHub repository.

METHODOLOGICAL IMPROVEMENTS

Researchers at NREL and other industry stakeholders have tested and compared many R_d calculation methodologies, weighing factors such as ease of use and the amount of time needed to determine a degradation rate with a relatively low degree of uncertainty. RdTools not only compares favorably in these regards, but also offers statistically robust analysis in relation to common problems associated with data quality. Specifically, RdTools avoids errors associated with linear regressions and tolerates imperfect sensor data as well as seasonality and seasonal soiling.

YOY analysis. The YOY analysis method in RdTools represents an improvement over classic linear regression analyses. The problem with regression line slopes is that these are sensitive to data outliers near the CONTINUED ON PAGE 34



Figures 1a & 1b Figure 1a (top) aggregates multiple ground-based irradiance sensor measurements. Note that the data for photodiodes 1 and 2 and reference cell 2 drift relative to the other regularly maintained sensors. The data in Figure 1b (bottom) detail the median PV system degradation rates that RdTools calculates for each irradiance sensor category based on a year-on-year (YOY) analysis, with the vertical black lines representing the ranges of confidence intervals. The green lines show the range and the dashed line shows the median of multiple Rd calculations for the system. While the sensor-based performance ratio (PR) results are vulnerable to sensor drift, the clear-sky–based results (PR_{CS}) are more robust.

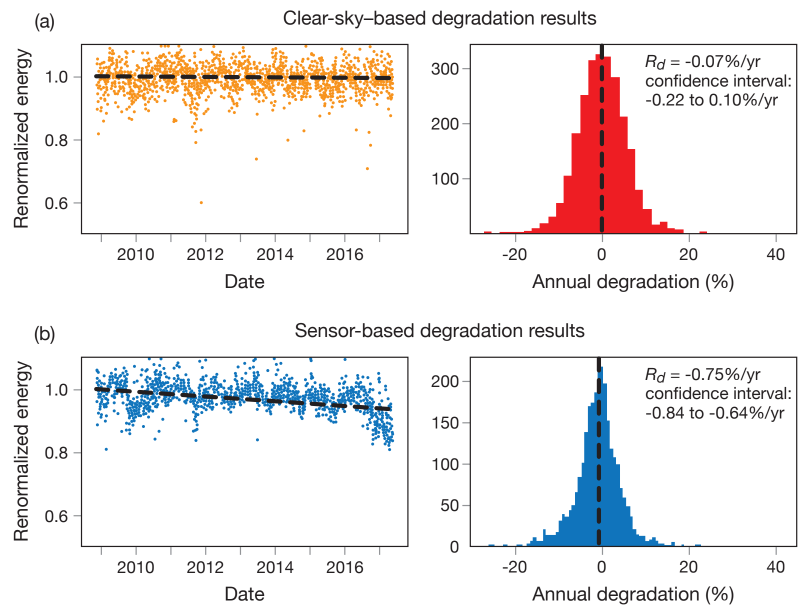
beginning or end of the line, as terminal data have high statistical leverage in regression analyses. Objectively filtering for outliers in a regression analysis is complex, as the filter needs to move in tandem with the unknown degradation rate to follow the gradual downward shift of the data.

In their *IEEE Journal of Photovoltaics* article "Robust PV Degradation Methodology and Application" (see Resources), Dirk Jordan and his co-authors found that a YOY method of calculating R_d reduced uncertainty relative to two different types of linear regression analyses. Because the YOY analysis calculates a median value from a distribution of R_d slopes, it is less sensitive to data outliers, as well as snow and soiling events. The YOY method is also resilient to data shifts, which often occur as the result of software changes or maintenance events such as sensor replacement.

If a data shift is subtle enough to go unnoticed, it can influence the results of linear regression analyses. By contrast, a median YOY R_d value is resistant to the influence of this type of data shift, as it will appear as an outlier on the histogram in a YOY analysis. Missing data have a similar effect. If end-of-year data are missing, data analysts conducting a linear regression analysis need to eliminate data for the last fraction of the year so that seasonal effects do not have an undue influence on the R_d results. The YOY technique, meanwhile, is tolerant of seasonal issues, meaning that analysts can use the full data collection time span, including fractional years.

Another problem with linear regression analyses is that they assume linearity. In the real world, however, linearity is not necessarily the case, as Jordan and others have shown in the *Progress in Photovoltaics* article "PV Degradation Curves: Non-Linearities and Failure Modes" (see Resources). RdTools' YOY analysis method limits the impact of nonlinearity by showing a distribution of degradation rates rather than a single value. If a system has, for example, two different degradation rates, switching from one to another at some point in time, users may see a pair of bumps in the histogram instead of a single peak. To detect nonlinear degradation, RdTools users can analyze multiple periods of time in 2-plus–year increments to estimate these different R_d values.

The assumption of linearity is also problematic if R_d calculations are conflated with the accuracy of nameplate ratings. The "Compendium of Photovoltaic Degradation Rates" (see Resources) compiles more than 11,000 degradation rates, revealing different findings for studies that relied on one performance measurement only compared to more detailed analysis. In particular, taking only one unconfirmed data point for



Figures 2a & 2b RdTools generated these YOY data graphs and histograms. It generated the data on the top (2a) using a clear-sky–based analysis; it generated the data on the bottom (2b) using a sensor-based analysis. Note that the sensor-based degradation results are sensitive to sudden shifts in sensor data, as occurs here in 2016–17. The visible drift that appears in the sensor-based data but not in the clear-sky data suggests that the clear-sky–based results are likely more accurate than the sensor-based results.

performance and relying on the nameplate rating instead of performance data may be inaccurate, especially in the case of older modules where the nameplate rating may have been slightly under- or overestimated. Newer PV modules have tended to demonstrate more accurate nameplate ratings, and quality modules are typically rated to take into account initial stabilization. The authors conclude that R_d calculations based on multiple clear-sky measurements, including initial post-stabilization values, are more accurate than those based on nameplate ratings and a single performance data point only.

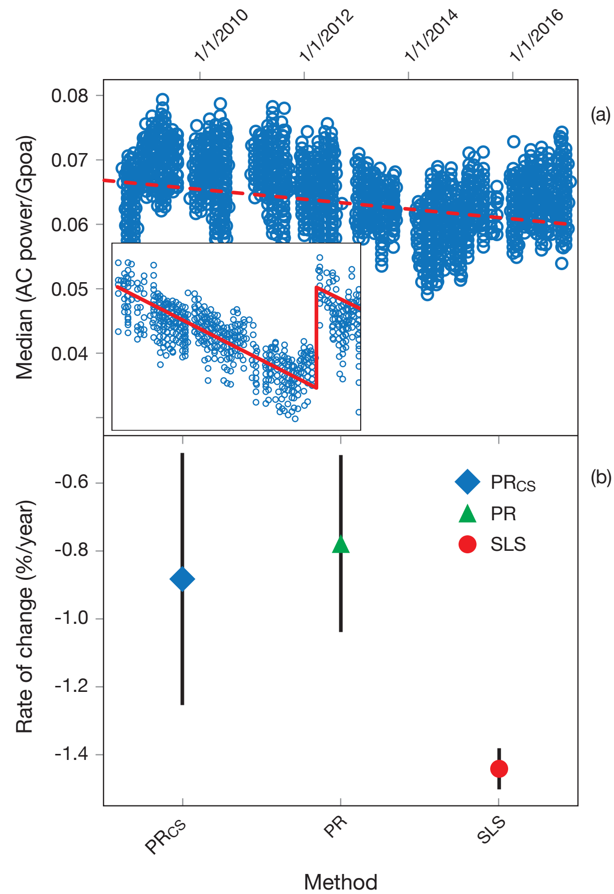
Imperfect sensor data. Based on their experience analyzing numerous fielded PV systems, the team of developers responsible for RdTools observed that irradiance sensors are not always well maintained in the real world. It was important, therefore, to develop an analysis method that could tolerate imperfect sensor data. The data presented in the *IEEE Journal of Photovoltaics* article demonstrate RdTools' usefulness in this regard.

The data in Figure 1a (p. 32, top), for example, aggregate measured plane-of-array irradiance (Gpoa) values for a variety of sensors. The blue diamonds represent a regularly maintained reference cell; the red circles represent the median of 10 regularly maintained pyranometers; and the green triangles, black squares and purple triangles represent unmaintained sensors. The data for photodiodes 1 and 2 and reference cell 2 illustrate the sensor drift that can occur when technicians do not regularly clean and calibrate irradiance sensors in the field. Compared to the reference cell, data from the unmaintained sensors drift by as much as 1.5% per year.

The data in Figure 1b (p. 32, bottom) illustrate the extent to which the clear-sky method in RdTools tolerates imperfect sensor data. The red circles in this figure represent YOY degradation rates according to RdTools' sensor-based calculation method; the blue diamonds represent YOY degradation rates according to the clear-sky methodology. The dashed line shows the median of 10 different conventional methods of R_d calculation, including time-series analysis and quarterly I-V measurements, and the green lines show the range of one confidence interval for these values. These data illustrate that while sensor-based R_d calculations are sensitive to the quality of ground-based measurements, the clear-sky method is considerably more robust.

As shown in Figure 2 (p. 35), analysts can also use RdTools to compare clear-sky–based (2a, top) versus sensor-based (2b, bottom) results. For the graphs on the left, RdTools normalizes performance ratio data to 1 and charts these values by year. The graphs on the right aggregate these YOY data into a histogram and report the median value as the R_d. The confidence interval represents one standard deviation of a bootstrap distribution. In this example, which assumes a clear-sky index filter of ±20%, the drop-off at the end of the sensor-based data in 2016–17 indicates a recent sensor problem. In this case, the clear-sky–based results are likely to be more accurate than the sensor-based results.

When the clear-sky and sensor-based results disagree, analysts should suspect a sensor problem and if possible arrange for sensor testing, calibration, cleaning or replacement. Sensor maintenance is a best practice as there is likely an upper limit to the degree sensors can be erroneous for either analysis method. It is important to note that the mathematical uncertainty represented by a confidence interval reflects the degree of variation within the given data set, but does not account for a problem such as a defective or unmaintained sensor. Confidence intervals are susceptible to the garbage-in, garbage-out challenge of all data analysis. However, YOY analysis with clear-sky normalization enables analysts to utilize, rather than discard, some poorly maintained sensor data.



Figures 3a & 3b The inset in Figure 3a (top) details a California site with seasonal soiling effects, which results in steady production declines followed by a sudden increase in production, indicating a rain or cleaning event. The results in Figure 3b (bottom) suggest that while the standard least square (SLS) regression method of calculating the rate of degradation is sensitive to seasonal soiling, the clear-sky–based (PR_{CS}) and sensor-based (PR) YOY methods respond more robustly to seasonal effects. The vertical black lines represent the degree of uncertainty.

If a system has well-maintained irradiance and temperature sensors, the clear-sky and sensor methods are likely to produce similar results and graphs. In a system with well-maintained sensors, the best option is probably to use the sensor-based degradation rate calculation since the uncertainty represented by the confidence interval can be lower compared to the clear-sky method, as is the case in Figures 2 and 3b.

Seasonality and seasonal soiling. Many PV systems experience predictable seasonal performance variations based on annual weather patterns, haze, spectral sensitivity, partial shading, snow or soiling. Whereas linear regression analyses are vulnerable to seasonal effects, the YOY methods that RdTools uses to calculate R_d values are more robust.

As an example, the repetitive data patterns in Figure 3a (top) are the result of variations in power production for a PV system in California due to seasonal soiling. As shown in the inset detail, soil builds up on the array throughout the dry season, resulting in a steadily decreasing performance ratio; cleaning or rain events produce a noticeable upward data shift. The data in Figure 3b (bottom) show that a standard least square (SLS) linear regression analysis overestimates the rate of degradation compared to degradation rates obtained using clear-sky– and sensor-based YOY methods. These results suggest that the two YOY methods are robust in relation to seasonal soiling events, a characteristic that likely extends to other seasonal effects such as haze or partial shading.

While the YOY and clear-sky methods are less sensitive to a number of common data quality issues, analysts still require quality input data and good analysis decisions to achieve high-quality results. Prior to proceeding with any calculations, data analysts should assess data quality, check the PV system's maintenance log and look for issues that can mimic module degradation. Is there evidence that overgrown weeds or trees may be shading the system? Has the site experienced tracker outages? If so, analysts can determine an appropriate response, such as applying data filters or removing certain time periods from the analysis. While it is still essential that input data are reasonably accurate, the RdTools software package provides system owners and data analysts with consistent and validated methods for calculating PV degradation rates.

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Interview

An Experienced Perspective

Amanda Bybee, CEO

Amicus O&M Cooperative

In 2016, a subset of Amicus Solar member companies collaborated to secure a US Department of Energy SunShot Initiative award to launch the new Amicus O&M Cooperative. Their aim was to fill a specific solar industry need: providing streamlined, cost-effective O&M services to ensure that solar PV systems fulfill their performance expectations over the short and long term. Amanda Bybee serves as the CEO of the new cooperative. She has worked in the solar industry since 2003, first promoting renewable energy policy in Austin, Texas, while at Public Citizen, then moving to solar EPC companies. Bybee holds a BA from the University of Texas at Austin, and, through solar, has found her "inner engineer."

SP: Before becoming the CEO of Amicus O&M Cooperative, you were the director of strategic planning and initiatives at Namasté Solar, a founding member of Amicus Solar Cooperative. How did you set your sights on a solar O&M strategic initiative?

AB: Fundamentally, I believe that solar is one of the key solutions to climate change. For it to be regarded as a reliable technology, it has to deliver on the promise that it will operate for decades to come. A lot of us in the O&M cooperative regard it as our moral obligation as industry professionals to make sure that the technology we install today does what it's supposed to do.

O&M providers are among the key players that make that happen. In my history of working at EPC companies for the past 14 years, I have always found there to be an interest in diversifying revenue streams. Namasté Solar saw that potential a few years ago, when it first established its O&M department. In talking with some of the other members of the Amicus Solar Cooperative, we hatched this idea of creating a new cooperative that would be dedicated just to that.

In the last 10–15 years, it's just been this mad race to build new projects, and O&M has not factored as heavily into the equation as it's starting to. There are opportunities to create new standards, to become a lot more efficient and sophisticated in how we provide O&M services. That's exciting to me, to be part of the development and to get to apply an entrepreneurial spirit to an underdeveloped part of the industry.

SP: What are the benefits of bringing the cooperative model to solar O&M? What do you think you can leverage from the existing co-op members?

AB: Namasté Solar is a huge proponent of the cooperative model, and it has quite a track record of spinning off new ones. Namasté Solar itself is an employee-owned cooperative. It co-founded Amicus Solar in 2011 as a purchasing cooperative. I've spent the last 2.5 years there helping launch a new financial cooperative, the Clean Energy Credit Union. It received its federal charter last September as a dedicated financial institution to provide financing for clean energy products and services. Midway through that, we applied for the award for the Amicus O&M Cooperative. It became my joke at Namasté Solar that whenever we encountered new business problems, our first question was, "Is there a cooperative for that?"

We believe that there's an inherent benefit in cooperatives with the collaboration that they naturally foster, equal ownership and voting rights, and the shared risk and responsibility for all the owners. It's just a better way to do business. It levels the playing field so that you have less hierarchical relationships than you have in the traditional subcontractor relationship, which leads to greater respect among companies.

One of our core values is fairness. We apply those core values not only to the members of the cooperative but also with our clients. We want to work with clients who understand that you can't just push 100% of liability off on other people. Liability exists in this world. And we have to be respectful and responsible in how we apportion it.

SP: What are the benefits to a company in becoming a member of the O&M cooperative?

AB: One of the primary services that the cooperative offers is to create a central infrastructure that allows us to work together and provide coordinated services across the country. So for the last year, we've been putting together a library of legal templates that members can use with clients to hopefully cut down on the amount of time it takes to negotiate a contract.

Another big tool is the central software system to track work orders into a ticketing system. Everybody is using a central system that asks the technicians to fill out a common checklist, which captures a common set

Courtesy Amicus O&M Cooperative

Focus on consistent training Bybee (top, center) joins some of the member company technicians during an Amicus O&M training session at Solar Energy International in Paonia, Colorado.

of information. Then it also generates standardized report templates.

SP: So you're addressing some of the soft costs and streamlining things for the members.

AB: Exactly. We also emphasize training, because part of the promise of creating this greater level of consistency and standardization is in having all the technicians train to a certain level. We partnered with Solar Energy International in 2017 and trained technicians from all 20 member companies, 45 in all.

Inherent in a cooperative is the sharing of best practices. It's a way to share experiences and new tools, ideas, marketing concepts and so on. It's also a way for us to have an internal marketplace for spare parts. That's a big thorny problem that everybody encounters. What do you do when you can't find parts to replace the broken ones?

There's also a lot of potential for workforce sharing. If you've got a big job and you'd like to have more technicians than you have on your team, you call your fellow co-op members and see if anybody else has some technicians they can share for a few days. If you're getting out on a new site, but it's really closer to someone else, you can work together to provide the services.

The other reason a lot of companies have joined is that the co-op is a potential revenue driver for them. They can be the recipients of work orders. Sales companies can have a reach into new markets.

The last thing is the tool lending libraries. We've been able to purchase some tools that members can now borrow and supplement what they already have. We've got some higher-end I-V curve tracers and three thermal imaging cameras. Given a few days' notice, I can ship them wherever member companies need them.

The companies have said that it's been helpful to have access to tools they themselves don't currently own that are faster at taking the readings, and that they've been able to use them for training others. Lastly, for big commissioning jobs, they've been able to do more concurrent testing and reduce time on-site, for greater efficiency overall. Win-win-win.

Really, that is what the cooperative is all about: raising standards and consistency across all of the member companies, and enabling them to do the work more efficiently so that we save time and money.

SP: What's the value for customers in hiring co-op member companies?

AB: The biggest one is access to a national network of contractors with trained technicians. They also have access to the software, so they can see the information relevant to their sites, their work orders, their upcoming invoices, their reports and so on, with a great deal of consistency.

If you're an asset owner, and you don't want to manage a lot of regional contractors, you could work with just one member company that would be your single point of contact. It would handle all the dispatch and management on the back end.

Because we're trying to fill in the map with member companies from all over the US, there will hopefully be less travel time. You'll have faster responses to get out and address problems and lower costs as a result.

The level of redundancy in having all the members of the cooperative trained in the same tools allows you to substitute one member company for another if necessary.

SP: What types of clients and market sectors does the Amicus O&M Cooperative serve?
AB: Originally, we thought we'd serve the C&I and small utility–scale marketplace. I've had a fairly large number of inquiries about residential fleets, and that's certainly on the table for the future. Our ideal client manages a geographically diverse project portfolio with systems ranging in capacity from 250 kW–500 kW up to 20 MW–30 MW, and outsources its O&M work. Then the other thing we look for is that our values are aligned.

SP: How sophisticated are your customers about solar O&M requirements?
AB: It's a pretty broad spectrum, actually. When you talk to professional asset owners and asset managers, they, of course, are very knowledgeable. They have high expectations of the services that we provide. Then there are others who are new to the role and need a lot of education. In some cases, people know exactly what they want, and they hand you the scope of work. In other cases, they say, "What are you gonna do for me?"

It's been interesting to explore the gaps between the financially minded and the technically minded, because they don't always understand each other's perspectives. The financial folks may want something that is not actually reasonable to provide, and the technicians don't always understand the financial impact of what they're doing. Being a bridge between those groups is one of the roles that I hope to play. I love the field side of things and have gotten to know the technicians from all of our companies through our trainings, but then I'm also out there talking to the asset owners.

"The members of the cooperative fundamentally understand that what's good for one is good for all, and we all win when we elevate our services and our sophistication."

SP: Do you think that industry stakeholders have a good understanding of how to value and budget for long-term solar O&M?
AB: In many cases, no. They may think far enough out to request an O&M contract from a service provider to cover the annual preventive maintenance inspections, but they may not think through the comprehensive costs that come with system ownership (corrective maintenance budget, DAS subscriptions, internet access, security and so on). When asset owners under-budget for O&M, it sets up a chronic tension between them and the O&M provider. There is still more education to do in the marketplace about how to have a realistic budget.

SP: As a for-profit business, the Amicus O&M Cooperative obviously sees a significant business opportunity in providing solar O&M services. How do you manage the balance between healthy competition and cooperation?
AB: One of the things that's been very interesting is learning about how the cooperative needs to operate with regard to antitrust laws. We are very careful in how we structure ourselves and how we function so that we preserve competition. We pay attention, certainly, to how much overlap and redundancy member companies create in any given geographic region, but we don't prohibit it. It's certainly possible that members of the cooperative will compete against each other. This may be one aspect of our practices that gives confidence to the asset owners—that we aren't complacent in our pricing. Healthy competition keeps us (and our pencils) sharp.

There is so much runway for improvement that we have got to be in this together. And the more we learn, the more we develop, the better we are as an industry. The better we are, the more we are able to provide a better, more efficient service, at a lower cost.

SP: How do you think the recent 30% solar tariff will impact the industry from a solar O&M perspective?
AB: There are a few potential impacts. Currently, the members of the cooperative are all also EPC firms, not just pure-play O&M companies. The same is true for a lot of O&M providers across the country. If they were to see their EPC business affected and were to lay off any kind of field staff, that could potentially mean that they have fewer resources to provide O&M services. Conversely, potentially more companies will see O&M as a safer revenue source. They could choose to get into the business and make it a more crowded marketplace.

The biggest impact of the tariff from my perspective was the uncertainty it introduced. It held up the development of a lot of projects, so all those new O&M contracts went on hold as well.

Now that the tariff is a known quantity, we can get back to business. This space is the solar coaster, and we know how to roll with the punches. We've had a lot over the past 15 years. I'm not too concerned about the medium- to long-term view. We will find ways to absorb the tariffs and continue growing.

CONTINUED ON PAGE 42

SP: Is there anything that you are working on now with the O&M co-op that you're just excited to talk about?

AB: I'm most excited about the opportunity to keep improving this part of the marketplace and to bring an entrepreneurial spirit to it while it is still figuring itself out. It's fun to have conversations with people about how do you define asset management. What falls into that exactly? When you say "analytics," what do you really mean? These are terms that people throw around as buzzwords, but there isn't a common understanding of how we really apply them in practice. I like to break that highfalutin term into really practical chunks.

I'm excited about the software side of things. More companies are providing important services and giving us better visibility into how PV systems are doing or why they're not performing as well as they should. I spent a lot of my time over the past 8 months developing software to manage, in our case, just really a narrow slice of that pie, which is the work order system. I'm finding ways to do that for my members that are affordable because pricing is still all over the place, both for software services and for O&M. We're approaching these things creatively and comprehensively, but also affordably. It's easy to get complicated.

We're trying to strike a balance and develop tools that are simple enough to be user friendly, but thorough enough to be useful on the back end. A lot of us fall into the trap of gathering so much data that we don't know what to do with it. How do we find the right balance of information to really be good at what we do and not overwhelm each other with all this unnecessary information that just clutters the space? After 11 years at Namasté Solar, my stock answer to every such question is "It's a balance."

If you have so much information, you can do a lot with it. But if you have too much and no one uses it at all, then you've shot yourself in the foot. Conversely, if you don't have enough, then you're flying blind.

We're constantly striving for that balance. We want to make sure the technicians are equipped to provide the right level of service. No one size fits all in every situation, so we strive to find the right ways to address that and apply different scopes of work to different-sized systems or different price tags. We want to get this to where we can provide O&M really cost effectively, still keep the systems up and running, and allow our companies to make some money along the way.

PROJECTS

System Profiles

Sun Light & Power
San Jose Environmental Innovation Center

Courtesy Sun Light & Power (4)

Overview

DESIGNER: Ivy Dwiggins, project engineer, Sun Light & Power, sunlightandpower.com

SUPERINTENDENT: Bailey Smith, PV and solar thermal superintendent, Sun Light & Power

LEAD INSTALLER: Jack Lai, PV foreman, Sun Light & Power

DATE COMMISSIONED: July 2016

INSTALLATION TIME FRAME: 90 days

LOCATION: San Jose, CA, 37.3°N

SOLAR RESOURCE: 5.15 kWh/m^2/day

ASHRAE DESIGN TEMPS: 90°F 2% average high, 32°F extreme minimum

ARRAY CAPACITY: 381 kWdc

ANNUAL AC PRODUCTION: 563 MWh

The San Jose Environmental Innovation Center (EIC) brings environmental and economic benefits to the region. The facility itself is a showcase of energy- and water-efficient practices and is home to three tenants: Prospect Silicon Valley, a technology demonstration center; a Habitat for Humanity ReStore; and a county collection center for household hazardous waste. Adding solar to this state-of-the-art facility was a logical step to achieving the center's sustainability mission and a net-zero building. Instead of allocating money and resources toward constantly escalating energy costs, the center can instead focus on its regional mission to support San Jose's green vision goals by helping to create clean-tech jobs, to reduce regional per capita energy use by 50%, to build or retrofit 50 million square feet of green buildings, to recycle or beneficially reuse 100% of wastewater, to divert waste from landfills and to replace San Jose's streetlights with zero-emission lighting.

A 6,600-gallon water storage tank collects and stores rainwater captured from the facility's watershed—its roof. EIC uses this water to irrigate a grove of 100-year-old olive trees. Sun Light & Power is particularly fond of this project, not only because of the challenge it posed and the success attained in its design and workmanship, but also because the PV system supports a center that represents the company's values of community, environmentalism and sustainability.

The Center's designers went to great lengths to make the facility solar ready in anticipation of installing this system. As

often happens, these efforts had mixed success. On the one hand, the team made the interconnection of sixteen 4/0 conductors to the supply side of the existing main switchboard significantly easier by preplanning for sufficient lugs in the appropriate location. On the other, the construction crew did not properly locate or mark the spare underground conduits out to the parking lot, and they buried the stubs below grade, so it took significant time to discover, expose, identify and retrench those conduits to make them usable.

The flat-roof portion of the project had existing stanchions that the construction crew had installed and waterproofed for the PV system. However, the stanchions were spaced 19–21 feet apart, much too far for an off-the-shelf PV racking system. A custom, multilayer W8x18 beam and purlin structure (as opposed to a truss system) was necessary to maintain a low profile and to achieve the spans that the existing stanchion spacing required.

In the same spirit of preparing for the future, Sun Light & Power designed the PV system for a planned addition of 100 kW of solar capacity. The team installed five 20 kW inverters and associated ac wiring for that expansion. Sun Light & Power also up-sized the PV inverter accumulation panelboard and associated feeders and interconnection equipment to include capacity for the addition.

> "It's exciting to see how bright green San Jose can be!"
>
> *—Bailey Smith, Sun Light & Power*
>
> "Sun Light & Power had the best proposal, experience and expertise to complete the project to the City of San Jose's high standards. It's rare to meet a solar company that has lasted so long. The savings greatly reduce the overall operating costs of the center."
>
> *—San Jose Environmental Innovation Center*

Equipment Specifications

MODULES: 1,164 SunPower SPR-E20-327-COM, 327 W STC, +5/-3%, 5.98 Imp, 54.7 Vmp, 6.46 Isc, 64.9 Voc

INVERTERS: 3-phase 277/480 Vac service, 21 SolarEdge SE20KUS, 20 kW rated output, 980 Vdc maximum input, 1,164 SolarEdge P400 optimizers (one per module), five of 21 inverters installed for future expansion

ARRAY: 33–37 module source circuits (36 or 37 modules typical), P400 optimizers connected in series with Voc of 1 V per optimizer, operating voltage nominally 840 Vdc (set by inverter), 15 A maximum optimizer output current, two source circuits per inverter, source circuits terminated at inverter wiring box with no external combining

ARRAY INSTALLATION: Three array types: **1)** new custom solar shade structures over the parking lot, three structures with 216 modules each, 648 modules total, 230° azimuth, 5° tilt; **2)** new custom wide-flange beam structure on flat roof, IronRidge XR-100 rail, 181 modules and provision for 306-module future expansion, 230° azimuth, 5° tilt; **3)** flush-mount standing-seam metal roof, S-5 clamps, IronRidge XR-10 rail, 335 modules, 140° azimuth, 5° tilt

SYSTEM MONITORING: SolarEdge SE1000-CCG-G plus weather station, building demand monitoring, custom DGLogik interface with existing building management system and custom touch-screen kiosk

Advertiser *Index*

Isolux Corsan and Soltec

Kayenta Solar Facility

Courtesy Soltec

Overview

EPC firm: Isolux Corsan, isoluxcorsan.com

INTEGRATOR: Soltec, soltec.com

DESIGNER: Antonio José Ros, mechanical design manager, Soltec

LEAD INSTALLER: Javier Carpio, director of operations, Soltec

DATE COMMISSIONED: June 2017

INSTALLATION TIME FRAME: 6 months total, 3 months for tracker installation

LOCATION: Kayenta, Navajo County, Arizona, 36.7°N

SOLAR RESOURCE: 6.3 kWh/m²/day

ASHRAE DESIGN TEMPS: 98.6°F 2% average high, 15.8°F extreme minimum

ARRAY CAPACITY: 37.6 MWdc

ANNUAL AC PRODUCTION: 76,037 MWh

The Kayenta Solar Facility represents the first utility-scale solar power plant in the Navajo Nation, located at the gateway to Monument Valley, 300 miles north of Phoenix. The technically challenging project took shape on sacred land, stewarded by a reverent nation. Strict project criteria required that most of the construction team be members of the Navajo Nation, that they preserve the natural landscape during installation and that they effectively restore it if the plant is removed when it reaches the end of its operational life.

The Navajo Tribal Utility Authority (NTUA), which provides utility services for the Nation, contracted Isolux Corsan as the EPC firm to oversee the installation of this landmark 37.6 MWdc project. Isolux relied on the technical expertise of its partners, including Soltec, which supplied and installed the PV trackers during the harsh desert winter. Soltec recruited and trained 188 members of the local community, representing 98% of the installation workforce, in record time—only 3.5 months.

Another critical condition of the Kayenta Facility was to limit earth grading and other environmental impacts while achieving the greatest possible yield per acre. To maintain the natural environment during installation, Soltec supplied its SF Utility single-axis tracker with land-use features that minimize all civil works and optimize yield density for maximum land utilization. The trackers used in Kayenta required only 10,864 driven-pile foundations for the 37.6 MWdc plant. Additionally, a slope tolerance of 17% north-south,

Courtesy KY Solar

Courtesy Soltec (2)

a short-step tolerance of 120 feet and contour tolerances to ±0.66 feet significantly reduced the need for grading.

Other noteworthy aspects of the Kayenta project include the following: The team optimized the layout of the length and the width of inner roads, resulting in fewer trenches and saving 23 miles in alternative wire management. They also used a unique cabling solution to locate the PV Wire homeruns inside the trackers' torque tubes, substantially reducing labor hours required for trenching, trays and hanging cables. Lastly, the wireless mesh communication network used on-site allowed the team to streamline installation, reducing communication wiring and conduits by 80%.

NTUA established a power purchase and renewable energy credit agreement with Arizona's Salt River Project Power District. Revenue from the Kayenta project is helping NTUA extend electricity to several communities on the reservation, significantly raising the standard of living for its families, some of whom have never before had electricity delivered to their homes. The Navajo Nation plans to bring more renewable energy capacity online as NTUA prepares to sunset a coal-fired power plant in northeastern Arizona.

> "The Navajo Nation has always had to purchase energy from the outside. Now we can sell electricity and environmental attributes to other parties. This project gives us the opportunity to bring outside dollars in and contribute to the financial strength of the Navajo economy."
> *—Walter Haase, general manager, Navajo Tribal Utility Authority*

Equipment Specifications

MODULES: 87,856 Jinko Solar JKM320PP-72, 320 W STC, -0/+3%, 8.56 Imp, 37.4 Vmp, 9.05 Isc, 46.4 Voc; 30,096 Jinko Solar JKM315PP-72, 315 W STC, -0/+3%, 8.48 Imp, 37.2 Vmp, 9.01 Isc, 46.2 Voc

INVERTERS: 10 GPTech WD3 Inverter Stations with 3.6 MWac capacity each; 1,000 Vdc–rated input (1,100 Vdc maximum input), 670–950 Vdc MPPT range, inverters positioned in two rows of five units, each row with independent entrance to the 24.9 kV side of the 66.9/24.9 kV substation

TRACKERS: 1,552 Soltec SF Utility independent-row single-axis trackers, 2 by 38 portrait module configuration, 120° tracking range, asymmetric backtracking, self-powered with battery backup, wireless mesh network communication

ARRAY: 19 modules per source circuit (for 320 W modules: 6,080 W, 8.56 Imp, 710.6 Vmp, 9.05 Isc, 881.6 Voc); eight, 12 or 20 strings per combiner (for 20-string combiner: 121.6 kW, 171.2 Imp, 710.6 Vmp, 181 Isc, 881.6 Voc); 37.594 MWdc array total

ARRAY COMBINERS: 321 Renovagy combiner boxes with eight, 12 or 20 strings each, polyester enclosure, SPF Type fuses, S6000 DC UL disconnect switch

ARRAY INSTALLATION: Ground mount with single-axis tracking, 10,864 driven-pile foundations

SYSTEM MONITORING: Custom SCADA system by Isolux Ingenieria