February/March 2014

PII Soft Costs | Training Best Practices

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PVSyst Simulation

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The Right Mount

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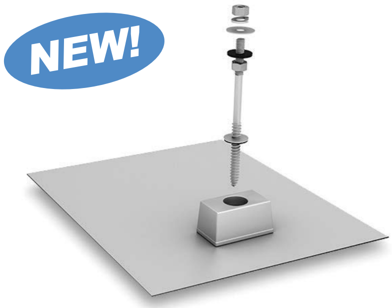

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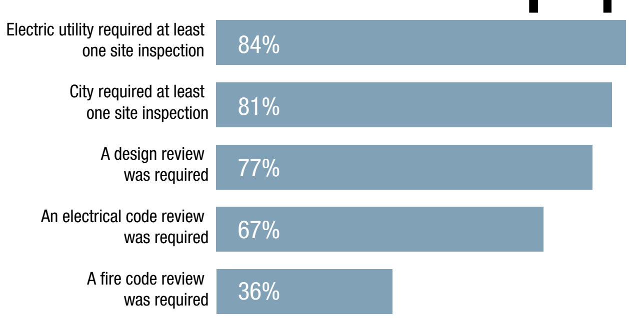

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ON THE COVER

690 Electric's J.R. Whitley gets down to the nitty-gritty of system commissioning at the Warsaw II Solar Farm in Warsaw, North Carolina. 690 Electric provided design consultation, third-party quality assurance inspections and commissioning services for the 2.6 MW project, which includes 8,740 ET Solar modules and four AE Solar Energy AE 500NX-1kV inverters.

Photo Courtesy Max Isaacs/690 Electric

CORRECTION: In the "Raceway Selection and Installation for PV Systems, Part Two: Design and Installation" article published in *SolarPro* magazine, December/January 2014, the raceway type in Diagram 2 was incorrectly labeled as EMT. The values shown in the diagram are for PVC.

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This 100kW PV system shown on the Beeston Hill Fitness and Rehabilitation Center on St. Croix is one of many installations completed by VI Solar Depot. The system contains 400 255W monocrystalline modules, two 33.3kW Fronius CL Inverters and two 11.4 Fronius IG Plus V series inverters. VI Solar Depot is a valued altE Direct customer and another great solar installer success story!

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Contributors

Brian Mehalic is a project engineer for O2 Energies. He began his career as a project manager and lead installer at EV Solar Products and has worked in the renewable energy industry for more than 10 years. A NABCEP Certified PV Installation Professional and ISPQ certified PV instructor, Mehalic develops curricula and teaches classes for SEI.

Sean Milich is a product manager with Clean Power Finance, a financial services and software provider for the solar industry and capital markets. He manages SolarPermit.org, focusing on product development and outreach. Milich graduated from Dartmouth College with a BA in economics and environmental studies.

Brian Radibratovic is the director of engineering at Power Analytics. He is a member of the IEEE-1584 working group and has published several papers. He holds one patent related to arc flash and has several patent applications pending. Radibratovic has a PhD in electrical engineering from the Georgia Institute of Technology.

Joe Sarubbi is a project manager for the Interstate Renewable Energy Council. A former journeyman electrician and professor with more than 35 years in industry and education training experience, he has garnered a national reputation for the design and delivery of renewable energy training programs. Sarubbi sits on the NABCEP board.

Finley R. Shapiro is the director of education and training in the Northern Mid-Atlantic Solar Education and Resource Center at Pennsylvania State University. He also does consulting and design for PV systems through his company, Finley Shapiro Consulting. Shapiro has a PhD in electrical engineering and is a licensed professional engineer.

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Solectria Launches Listed 1,000 Vdc Inverters

[Lawrence, MA] Solectria Renewables has released its next generation of SMARTGRID-series utility-scale inverters, the SGI 500XTM and SGI 750XTM. Both models are ETL listed for 1,000 Vdc PV plants and designed for 3-phase 380 Vac output for direct-to-medium-voltage connection via a Solectria-specified external transformer. The 500 kW and 750 kW inverters have a CEC-weighted efficiency of 98% and offer grid management options that include real power curtailment, reactive power control, and voltage and frequency ride-through. The products' MPPT voltage range is 545–820 Vdc. Data monitoring options include Solectria's SolrenView web-based monitoring, revenue-grade metering, SolZone subarray monitoring and cellular communication. The SGI 500XTM and SGI 750XTM inverters have a 5-year standard warranty. Optional coverage includes 10-, 15- and 20-year extended service agreements and uptime guarantees.

Solectria Renewables / 978.683.9700 / solren.com

Quick Mount PV Adds Low-Cost Mount

[Walnut Creek, CA] Developed for price-sensitive pitched-roof projects, the new E-Mount product from Quick Mount PV is compatible with composition asphalt shingle roofs. For weatherproofing, the IBC-compliant mount includes a 9-by-12-inch aluminum flashing and a patented QBlock elevated water seal. The E-Mount is designed for integration with standard 5-inch to 5.625-inch shingle courses and requires no shingle cutting. The E-Mount comes with stainless steel hardware for single-lag screw-mount installation. The product has a 50-year expected life and carries a 10-year limited warranty.

Quick Mount PV / 925.478.8269 / quickmountpv.com

OutBack Power Introduces AC-Coupling Solution

[Arlington, WA] The FLEXcoupled system from OutBack Power utilizes an AC-Coupling Center (GSLC 175-AC-120/240) to provide stable electro-mechanical coupling of grid-direct string and microinverters with OutBack's Radian GS8048 battery-based inverter. The solution is developed to be compatible with a wide range of string and microinverter products as well as array voltages of up to 600 Vdc. The FLEXcoupled solution provides backup for grid-direct systems with up to 6 kW of PV input. Designed for both new and retrofit installations, the full ac-coupling system from OutBack includes the AC-Coupling GS Load Center, Radian GS8048 inverter, MATE3 with mounting bracket, eight EnergyCell 200GH VLRA batteries and a two-shelf integrated battery rack.

OutBack Power / 360.435.6030 / outbackpower.com

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Panasonic Announces Bifacial Module

[Newark, NJ] Panasonic has redesigned and rereleased its HIT Double bifacial module. The HIT Double 225 features a new design that utilizes 72 five-inch cells. The result is a lower-voltage, higher-current product compared to the original 96-cell HIT Double module. The 225 W HIT Double 225 has a maximum power voltage of 43.2 V and a maximum power current of 5.21 A. Its c-Si cells include thin amorphous silicon layers. The HIT Double features glass-on-glass construction that allows light penetration and power generation from both sides of the module, making it well suited for deployment in awnings, canopies and carports. The product is currently available through a special-order procurement process.

Panasonic / 408.861.8488 / us.panasonic.com

Burndy Adds Bonding Products

[Londonderry, NH] Burndy recently released a new family of Wiley electrical bonding washers. The stainless steel WEEB-DSK line allows for a wide range of compatibility across various racking systems. The disk-shaped washer has eight bonding teeth around its perimeter to provide greater flexibility in creating module-to-rail bonds. The bonding washers are ETL listed to the UL 467 standard and are UL recognized to the subject standard UL 2703. Multiple disk designs accommodate mounting hardware sizes from ¼ inch through ½ inch. The WEEB-DSK516, suitable for 5⁄16-inch or M8 hardware, is currently in stock.

Burndy / 800.346.4175 / we-llc.com

Fronius USA Launches String Inverter Line

[Portage, IN] Fronius USA has introduced four new string inverter models for residential installations. The Galvo inverter series includes models with rated power outputs of 1.5 kW, 2 kW, 2.5 kW and 3.1 kW. The Galvo 1.5-1 and 2.0-1 models have an MPPT range of 120–335 Vdc. The MPPT range for the two higher-power units, the Galvo 2.5-1 and 3.1-1, is 165–440 Vdc. All models can be connected to 208 Vac or 240 Vac services. The Galvo inverters are low profile and lightweight (36.9 pounds) and feature an integrated dc disconnect and an innovative SnapINverter hinge mounting system that facilitates quick installation and serviceability. The high-frequency transformer topology allows for positive- and negative-grounded systems. Internal protective devices include a Type 1 arc-fault circuit interrupter (AFCI) and dc reverse polarity protection. The Galvo series inverters include integrated Wi-Fi and free data hosting on Fronius' SolarWeb monitoring portal for the life of the system.

Fronius USA / 877.376.6487 / fronius-usa.com

SolarBOS Announces Listed Arc-Fault Combiners

[Livermore, CA] SolarBOS's new line of ETL listed arc-fault detection (AFD) and arc-fault circuit interruption (AFCI) source-circuit combiners meet 2011 and 2014 *NEC* Section 690.11 arc-fault circuit protection requirements. The AFD combiners are rated for system voltages of up to 1,000 Vdc and are ETL listed to

UL 1699B for the detection of both series and parallel arc faults. The AFCI combiners are rated for 600 Vdc systems (1,000 Vdc rating pending) and listed for series arc interruption. Both combiners are available with 12- or 16-string inputs and have a maximum continuous output current rating of 250 A. The AFD circuitry communicates the presence of an arc via Modbus and opens dry contacts that can control a variety of devices. The AFCI combiner integrates a contactor with the AFD circuitry, eliminating upstream series arcs. Output terminals are 90°C rated. The combiners are offered in NEMA 3R, 4 and 4X enclosures. AFD/AFCI combiner configurations are available for grounded, floating and bipolar arrays.

SolarBOS / 925.456.7744 / solarbos.com

Unirac Introduces New Ballasted Racking System

[Albuquerque, NM] The Unirac RM Roof Mount is designed to minimize installation time and the tools required for commercial-scale ballasted rooftop projects. The system consists of three components: a ballast bay, a universal module clip and a chemical locking hex bolt. Each ballast bay is delivered fully assembled and weighs less than 4 pounds for easy handling. The module clip and hex bolt provide a UL 2703–certified grounding path between the module and ballast bay. The ballast bay is compatible with off-the-shelf wire management products. Optional roof pads are available. Unirac provides an online design tool to create RM Roof Mount layouts that you can directly share with your distribution partners. The RM product is backed by a 10-year structural warranty and 20-year workmanship warranty.

Unirac / 505.242.6411 / unirac.com

AEG Expands Utility-Scale Inverter Line

[Plano, TX] The UL-certified Protect PV.500-ID-UL and PV.630-ID-UL inverters from AEG Power Solutions are designed for the North American utility-scale PV market. The 510 kW and 630 kW inverters are listed for 1,000 Vdc applications. The PV.500-ID-UL has an MPPT range of 500–820 Vdc, and the PV.630-ID-UL has an MPPT range of 550–820 Vdc. Both inverters utilize external transformers for low- or medium-voltage grid interconnection. The inverters include grid management features such as reactive power control, low voltage ride-through and grid frequency stabilization. AEG Power Solutions offers turnkey solutions that integrate inverters, transformer, disconnects and switchgear into a container for on-site delivery.

AEG Power Solutions / 469.229.9600 / aegps.com

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Reducing Residential PV System PII Costs

In the last 5 years for which complete data is available, the US residential solar industry has exploded, growing from 82 MW of new installations in 2008 to 488 MW in 2012. A steep fall in the average installed system cost (from over $8/W to just under $5/W) accompanied this boom. Equipment and hardware prices dropped precipitously. Module costs fell from about $2.60/W to roughly $0.60/W over this period due to competition from abroad, advances in manufacturing, source-material cost reductions and oversupply. Equipment costs are projected to continue to decrease, but they have likely seen the majority of their reductions.

However, the industry is still grappling with stubborn non-hardware or *soft costs,* which include project financing; customer acquisition; labor; and permitting, inspection and interconnection (PII). The US Department of Energy estimates that soft costs account for more than 60% of a typical residential PV system cost. Arguably, the most unnecessary source of soft costs is the nationwide lack of standardization in PII for residential-scale PV systems.

The Permitting Landscape

There are more than 18,000 permitting agencies across the US, many of which have their own distinct permitting processes. This abundance of AHJs stems from the distribution of power locally and the autonomy of towns and communities. This can be a good thing, as only local communities can create and enforce the laws that may apply to their part of the country. However, the multiplicity of local laws can be burdensome to solar integration companies.

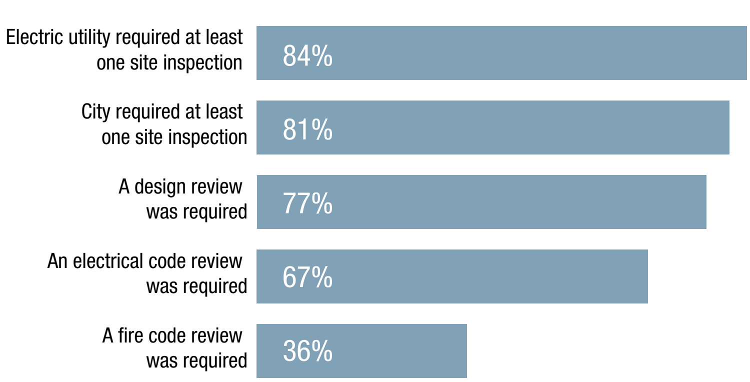
With the exception of adjustments made for climate-specific variables, the basic PV system designs utilized in residential solar installations do not vary significantly between sites. However, the AHJs' design requirements often do vary significantly. For example, one local building department may rarely encounter residential PV installations and therefore may not have standardized regulations, another building department may have overly strict requirements, and still another may have outdated rules based on past *NEC* cycles.

Unfortunately, PV integration companies have little choice but to follow the rules that the AHJs set. Navigating this vast world of requirements is particularly burdensome for small installers attempting to expand into new markets, since they may have to deal with different requirements for each installation in a new sales region. Even large national installers feel the negative impact of PII soft costs, which complicated and often conflicting AHJ requirements make onerous.

To further complicate matters, many jurisdictions require multiple agencies to review a residential PV permit application and perform inspections, which substantially slows the velocity of installations. The order and timing of the review and inspection process also varies from one community to the next. The large number of parties involved may confuse installers, and this confusion can lead to improperly submitted permitting packages, poor communication between stakeholders and increased administrative costs for installers and AHJs alike.

A Baseline Permitting Study

In 2012, as part of a SunShot initiative under the US Department of Energy, Clean Power Finance conducted a study to assess the problems associated with residential solar permitting. The overarching goal was to inform the development of solutions CONTINUED ON PAGE 16



AHJs involved	Percent of installations
Electric utility	55%
City planning office	61%
County planning office	35%
City fire department	13%
County fire department	10%
Other	17%
Average number involved	1.94
Maximum number involved	5

Courtesy SolarPermit.org

Lack of standardization Clean Power Finance collected data that shows the complexity and lack of standardization integrators face during residential PV system permitting, inspection and interconnection activities.

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To learn more, call (802) 872.9600 or email info@allearthrenewables.com that would significantly decrease PII costs. This study included a comprehensive survey of 273 installers as well as qualitative interviews with installers and AHJ staff members. We collected PII data on more than 500 installations in the top 12 solar states that comprise over 90% of the residential solar market in the US. We found that:

- More than one in three installers avoid selling in an average of 3.5 jurisdictions because of permitting difficulties.
- Permitting processes vary widely among locales and usually involve two to five agencies, each with different processes.
- AHJs require, on average, nearly 8 workweeks to complete their tasks. However, the installer's associated staff time averages just 14.25 hours.

While our survey provides a comprehensive overview of the challenges integrators face related to project PII, the interviews offer a more detailed understanding of the problems from both sides. One common theme is that the varying requirements across AHJs frustrate installers. Kelcy Pegler, Jr., cofounder of Roof Diagnostics Solar, explains: "The biggest pain point with solar permitting is the lack of standardization. Each municipality, each inspector, each division has their own perspective and set of expectations for a residential solar install." AHJ responses frequently pointed to the importance of regulations to protect homeowners. As one AHJ staff member notes, "Requirements are not a matter of red tape, but safety." Although both sides have valid points, room for standardization certainly exists.

Common PII Issues

Three primary issues are responsible for the high cost of PII for residential PV systems in the US: lack of standardization in permitting, lack of resources, and inaccessible and inaccurate requirements.

Lack of standardization. The absence of standardization can take on several forms. One issue is that the interpretation and enforcement of an AHJ's requirements can vary from one department employee to the next. Proper staff training and documentation processes can address this issue. Of greater concern is the lack of standardization among jurisdictions nationwide. I have spoken with installers who can point to neighboring communities with nearly identical climates but very different permitting processes and requirements. Similar situations are likely to occur in areas where solar is a relatively new technology without an established precedent, or in communities that view changing the status quo as an unnecessary burden for department employees.

Lack of resources. In our interviews, installers and AHJs alike complained of long turnaround times for permits due to the *tollbooth problem*—when permitting approvals are backed up due to understaffed and overworked department employees. The available personnel-hours of a jurisdiction limits the number of permit packages it can process and inspections it can perform. To complicate matters, an installer who is submitting a permit package in a new service region is more likely to submit an incomplete or incorrect package, which consumes still more department staff time. As the solar industry continues to grow, the volume of permitting applications and scheduled inspections will only increase. AHJ staff will likely spend more time reviewing faulty applications, leaving less time to evaluate correct applications. The tollbooth problem slows down projects and can be an unnecessary drain on AHJ and installer resources.

Vermont is one state that has successfully tackled the tollbooth problem. Before 2012, an installer would have to apply for a Certificate of Public Good (a permit) from Vermont's Public Service Board. Last year, Vermont flipped the permitting process on its head: It now green-lights all residential PV systems that meet predetermined criteria, as the vast majority do. The utility serving that system has 10 days to raise any interconnection issues; otherwise, the system receives the Certificate of Public Good and can move forward. While this approach has been successful in Vermont, it will not work as well in states that include multiple climate zones.

Inaccessible and inaccurate requirements. The interviews produced another telling insight: Installers often do not know how to access requirements, or do not understand the requirements they must meet. AHJs cited errors in permit packages and incomplete or inconsistent paperwork, such as the design not matching the system documentation, creating extra work and delays. One AHJ interviewee noted, "Perhaps a fifth of submittal packages are poorly organized and may require hours of red-lining."

While defective permitting packages are due in part to installer carelessness, the interviews strongly suggest the bigger problem lies in the communication of the requirements. Frequently, installers do not know where to find new requirements, or discover that requirements have changed or that an AHJ's staff enforces them inconsistently. These issues include not knowing how to access the requirements for a particular AHJ, instances where the AHJ updates requirements without notice, or cases where the AHJ does not interpret specific requirements consistently from one project to the next. One installer noted, "AHJs can change their interpretation of existing codes, and you only find out after you submit your paperwork." Residential PV installations are relatively new to many jurisdictions, and, though some may be aware of guides to help streamline the solar permitting process, only a few will have the time and resources to implement these simpler standards and procedures.

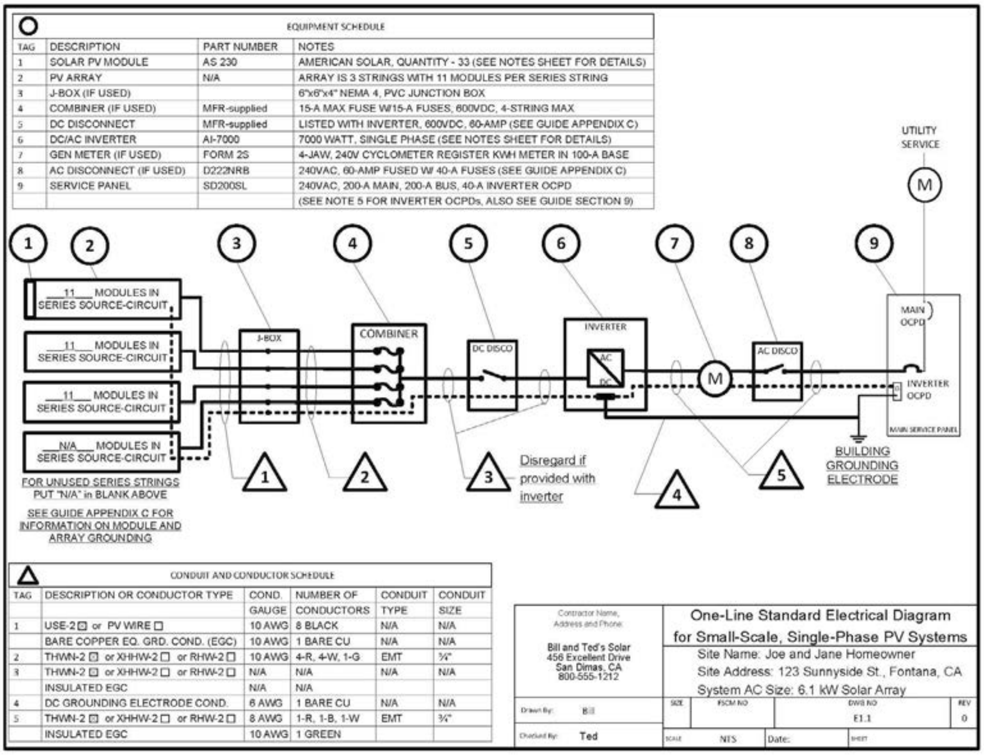
Reducing PII Soft Costs

Tellingly, the problems that installers and AHJs face are different sides of the same coin. A national approach to permitting processes would benefit solar companies and AHJs alike. Multiple initiatives aimed at standardizing and streamlining these processes and reducing PII soft costs are under way.

NREL. In August 2013, the National Renewable Energy Laboratory (NREL) published "Non-Hardware ('Soft') Cost-Reduction Roadmap for Residential and Small Commercial Solar Photovoltaics, 2013–2020" (nrel.gov/docs/fy13osti/59155.pdf). Members of NREL and the Rocky Mountain Institute authored the comprehensive 85-page report. It provides a detailed road map for reducing project soft costs, including those in the PII category. The report points to five solution sets that the industry and regulatory bodies need to address: (1) standardization of requirements, (2) transparency of requirements, (3) online permit application submittal, (4) lowering market-wide average permitting fees and (5) interconnection best practices. The authors present various cost-reduction projections required to drive PII soft costs from the 2010 baseline of approximately $0.20/W to $0.04/W by 2020.

Solar ABCs. In July 2012, the Solar America Board for Codes and Standards (Solar ABCs) published "Expedited Permit Process Report, Revision 2" (solarabcs.org/permitting), authored by Bill Brooks, PE. The report provides standard electrical diagrams, site plans and forms that local jurisdictions can use to develop streamlined permitting requirements for most residential PV systems. It helps AHJs distinguish between PV systems that they can quickly permit due to their similarity to the majority of small-scale systems, and systems with unique characteristics that may require a more time-intensive application and review process.

SolarPermit.org. Clean Power Finance developed SolarPermit.org (solarpermit.org) and its National Solar Permitting Database with a grant from the US Department of Energy's SunShot Initiative. This free online database provides information on permitting requirements on jurisdictions nationwide. Uniquely, both installers and jurisdiction representatives can enter permitting requirements on a given jurisdiction's webpage in the



Courtesy Solar ABCs

Expedited Permit Process Bill Brooks developed the "Expedited Permit Process," which Solar ABCs published. The resource includes electrical diagrams and forms to help standardize AHJ processes and reduce the soft costs associated with residential PV system permitting and inspection.

database. The site employs a community voting system to verify the accuracy of permitting requirements that representatives have added to the database. It also hosts a forum where installers and AHJ employees can post information on developments related to permitting, soft costs and the solar industry in general.

In addition to collecting permitting data, SolarPermit.org allows users to view reports on AHJ performance, including the national average of permitting fees or process times. This visibility can help AHJs see how they compare to the national average, understand trends and in turn streamline their procedures and requirements.

With permitting information covering more than 5,000 of the most active solar communities in the US (by volume of solar installations), SolarPermit.org enables installers to post and view permitting requirements and jurisdictions to broadcast their permitting process to a national audience. Hollie Valtierra, the residential engineering manager at HelioPower, notes that her team previously "had a 4-page permitting requirements spreadsheet to track the individual jurisdictions. This required continuous upkeep. SolarPermit.org helps us track requirements and leverage information submitted by other installers." Valtierra has since replaced her spreadsheet with the continuously updated SolarPermit.org database.

SolarPermit.org actively partners with industry stakeholders to standardize PII best practices. For example, in September 2012, California passed SB 1222, which caps residential and commercial permit fees for rooftop solar energy systems that meet certain requirements. However, AHJ compliance with SB 1222 has been inconsistent. SolarPermit.org partnered with a coalition of solar installers, government entities, nonprofits and industry associations to help enforce compliance with SB 1222. While this example is specific to California, stakeholders can engage online with the SolarPermit.org team to help solve permitting issues in their respective city, county or state. Additionally, SolarPermit.org's source code is open and available for download. This presents a unique opportunity for individuals to participate in the development of the database to make the tool as useful as possible.

Project Permit. Vote Solar and the Interstate Renewable Energy Council (IREC) collaboratively developed guidelines for residential solar permitting best practices that they last updated in May 2013. These guidelines are an integral component of Vote Solar's Project Permit (projectpermit.org), an interactive website that facilitates the ranking of municipal solar permitting practices nationwide. Project Permit assists permitting staff, solar advocates and municipal leaders in understanding how their city's solar permitting process compares to best practices nationwide. The site matches best practice data fields to values pulled from SolarPermit.org's database. Providing AHJ-specific input to both SolarPermit.org and Project Permit will create greater visibility into nationwide permitting regulations, inform AHJs on permitting best practices and eventually help drive out some of the soft costs associated with residential PV system permitting, inspection and interconnection.

—Sean Milich / Clean Power Finance / San Francisco, CA / cleanpowerfinance.com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Solar Energy Education and Training Best Practices

Most installers learn early that the right tool for a job makes all the difference, not only in the quality of the workmanship but also in the speed with which they can complete the job. Through experience, you may have also learned that taking shortcuts often leads to a poorly finished product and, in many cases, one that does not last long.

Needing the right tools holds true when developing sound education and training programs, too. At the Interstate Renewable Energy Council (IREC), we witnessed this with the rapid growth of the solar industry and the buzz that ensued. A Wild West for solar training programs followed, often with the promise of jobs upon completion of a 1-week crash course. Organizations and institutions set up training programs practically overnight as the solar industry clamored for workers.

In many instances, the approach to this training was inconsistent and of poor quality, leaving many students unemployable. To be fair, well-intentioned instructors established many training programs, but some of these people lacked a thorough understanding of solar technology or the solar industry. Excellent training courses were few and far between.

The Solar Instructor Training Network

Building a skilled workforce starts with offering prospective employees high-quality education and training programs, which depend on sound instruction that well-trained teachers provide. The Solar Instructor Training Network (SITN) is helping to build that highly qualified solar workforce (see sitnusa.org). A 5-year US Department of Energy SunShot initiative, SITN consists of nine regional training providers and

a national administrator. Now active in nearly every state, SITN at its core is a train-the-trainer program. Its projects and tools are helping trainers make significant strides to fulfill the critical need for high-quality, accessible and industry-driven education in solar system design, installation, sales and inspection.

As the SITN national administrator, IREC has worked with the network's regional training providers and the solar industry to develop a series of tools for trainers. One of these tools, *Solar Energy Education and Training Best Practices: The Series,* is an online compendium of national best practices for instructors in solar training, education and workforce development. Written by leading experts in the solar industry and in education, the series is designed to give instructors the right tools for training a highly skilled and competent solar energy workforce. These in-depth resources support instructors in developing new solar programs, integrating solar content into related trades programs, and enhancing existing solar education and training programs.

Best Practices: The Series

The following is a description of the documents included in the compendium of best practices.

"Curriculum and Program Development." This document addresses teaching and learning strategies that promote effective instruction, focusing on two primary components of instructional systems design: development and implementation. Together they address teaching and learning strategies that promote effective instruction. Anyone who wants to be a good teacher needs to understand how students learn. This document examines the information-processing theory of learning and how it impacts lesson design, and presents an eight-step lesson design plan. It also briefly discusses some adult-learning principles that instructors can incorporate into teaching strategies. In addition, it provides a few tips for designing and using Microsoft PowerPoint presentations effectively.

"Becoming an Effective Teacher." A brief overview of the curriculum development process, this document focuses on developing a curriculum methodology and job task analysis. Its intent is to discuss the process of development rather than a specific set of courses that might constitute a particular curriculum or program.

"Developing a High-Quality Course." The quality of currently available courses ranges from highly effective (with stated learning objectives, student participation and assessments) to poorly designed and executed (using what is often CONTINUED ON PAGE 22

called the *sit and get* strategy). This document discusses how to develop a high-quality course, unit or lesson and introduces instructional models and practices that can be used for solar education and training. It includes a discussion of the broad concept of a systematic program plan and how to use instructional systems design to develop such a plan.

"Solar Content Integration." Is it better to educate and train solar specialists, or to provide supplemental solar knowledge and add-on skills to workers in more traditional occupations? Industry representatives agree that the added-skills approach is best. For example, providing a journeyman electrician with the skills necessary to install PV systems may be more prudent than training a PV installer from the ground up. If the solar market declines, the PV installer may be out of work, whereas electricians are still electricians and can apply their broader talents to other forms of electrical work. Even in a stable solar market, workloads may not be significant enough to keep PV installers fully employed.

The solar content integration document examines options for integrating solar content into existing education and training programs. Due to the current heavy dependency of solar markets and related solar jobs on federal, state and utility policies, the document considers options for a variety of solar occupations. The document's recommendations provide the needed instruction while minimizing the effects of market volatility and job uncertainty.

"Exemplary Solar Education and Training Programs." This document presents case studies on six solar education and training programs. These programs are complete, integrated and well organized, and provide a solid foundation for those entering the solar workforce. Entering students do not need significant background, experience or prerequisites.

The programs include a construction trade apprenticeship, three multicourse certificate trainings, and two Associate in Applied Science degrees. The number of instructional hours ranges from a minimum of 420 to more than 1,000. Each of the programs possesses distinguishing attributes that make it exemplary and deserving of review and possible emulation by institutions that are considering new solar program development.

"Textbooks, References and Instructional Resources." This document is intended to assist instructors in designing, developing and implementing courses in PV systems and solar heating and cooling (SHC) systems. It lists recommended training materials for both PV and SHC instructors; it also lists textbooks and key references that may be useful. Key references relate to occupational safety and health, electrical codes, structural building codes and plumbing codes, in addition to design and installation, minimum standards for equipment certification and effective training methods. In addition to providing technical references for both PV and SHC systems, the document includes links to useful magazines, online documents and websites.

"Photovoltaic Labs." This document is designed to assist faculty and administrators at colleges, universities, and other technical and training institutions who seek to develop new PV laboratories or to improve existing facilities. Instructors can use such laboratories for a variety of courses and programs to enhance learning and develop the skills of several target audiences. This document presents information on developing laboratories that are inclusive enough for PV system installation courses and programs. From this more comprehensive list, selected equipment can then be used in courses for PV designers, contractors, code officials, site assessors, sales personnel, building designers, utility personnel, business professionals and other PV-related occupations.

SITN Effectiveness

Initially, SITN sought to create a geographic blanket of high-quality, locally accessible solar training throughout the country. It is meeting that goal: To date, 874 instructor trainees have received instruction from regional training providers since the project began. Moreover, the regional training providers continue to engage new institutions seeking to establish solar programs in states that are seeing a sharp increase in solar installations. Today thousands of individuals have received solar training from instructors and programs established through SITN.

SITN is doing its part to improve the solar education and training acumen of instructors across the country, and IREC is ensuring that these instructors have the necessary tools to develop effective programs. The overall goal is high-quality, safe, cost-effective solar system installations for the growing number of consumers who want to benefit from solar energy.

— Joe Sarubbi / Interstate Renewable Energy Council / Latham, NY / irecusa.org

Commissioning and O&M Tools

By Brian Mehalic and David Brearley

We contacted PV project managers, commissioning agents, operations and maintenance (O&M) managers, service technicians and so forth—more than two dozen pros in total, representing every region of the country—and asked them questions like these: "What are your favorite meters, power tools and hand tools? What torque wrenches or drivers do you use? What is your most valuable tool?" In other words: "What's in your tool bag?"

In this article, we summarize some of the survey results, emphasizing test and measurement tools used to verify that systems are installed and operating correctly. We provide typical retail price ranges for test and measurement device models in brackets, when available online. We also provide some helpful application notes along the way.

ELECTRICAL POWER TESTERS

Surely we are not the only pros who occasionally suffer from a serious case of meter envy. Besides being the eyes and ears of the field technician, meters are fun and flashy. They can also be a significant investment. So before talking about some sexy meters, let us first cover some important business.

Electrical test meters must be able to withstand both the expected steady-state voltage of the system you are measuring and any transient overvoltages (short-duration surges or spikes: for instance, those caused by a lightning strike or electrical motor starts and stops). All meters produced since 1997 are identified with an overvoltage installation category (CAT) rating in accordance with the International Electrotechnical Commission (IEC) standard 61010-1, which details requirements related to the construction of low-voltage (<1,000 V) test and measurement equipment, as well as allowances related to their conditions of use.

As shown in Table 1, IEC 61010-1 defines four basic overvoltage installation categories for meters: CAT I–CAT IV. The technical basis for overvoltage installation categories is the relative threat presented by high-energy, lightning-induced voltage transients. Within each category, there are five possible working voltage designations: 50 V, 150 V, 300 V, 600 V or 1,000 V. All listed electrical meters are marked accordingly and should be used in accordance with their overvoltage installation category and working voltage designation.

Clamp meters. Not surprisingly, clamp meters received the highest number of "most valuable tool" votes in our survey. While some clamp meters measure current only, most models also perform many of the basic functions offered by a digital multimeter. Using a clamp meter is the best way to quickly compare source- or output-circuit currents. You can also use clamp meters to verify that no electrical current is flowing in a dc circuit before opening a non-load-break–rated disconnect—such as a module quick connect or a touch-safe fuseholder—to avoid pulling a potentially dangerous and destructive arc across the contacts.

Overvoltage Installation Categories

Measurement category	Application
CAT I	Protected electronic circuits
CAT II	Single-phase receptacle-connected loads
CAT III	Distribution wiring: main bus, feeders and branch circuits; permanently installed loads
CAT IV	Utility-level connections (revenue meters, primary OCPDs); any outdoor conductors

Table 1 The higher a meter's CAT rating, the closer you can use it to the origin of installation (the utility service drop). Most meters designed specifically for PV field applications, like I-V curve tracers, are CAT III rated at 600 or 1,000 Vdc.

The clamp meter of choice is the CAT IV Fluke 376 AC/DC True RMS Clamp Meter [$360–$450]. This meter is capable of measuring ac and dc voltages up to 1,000 V, which is an increasingly important feature given the trend toward higher PV utilization voltages. The fixed jaw is big enough to fit around a single 750 MCM conductor or two 500 MCM conductors, and can measure up to 1,000 A ac or dc. This meter is sold with a flexible meter attachment, the iFlex, which improves wire access and extends the ac current measurement range to 2,500 A. The Fluke 376 is a workhorse

Do you ever wonder what tools solar professionals carry when they are performing quality control, commissioning, or operations and maintenance activities on commercial and utility-scale PV systems? We did—so we found out.

Courtesy Max Isaacs/690 Electric

meter, a direct replacement for the now-discontinued 600 V–rated Fluke 337 clamp meter, which several survey respondents still carry. If you are in the market for a new clamp meter or need a multimeter that can measure up to 1,000 V, the Fluke 376 is an excellent choice.

Some survey respondents also carry CAT III-600 V–rated clamp meters, such as Extech Instruments' MA220 and EX730 models and Klein Tools' CL2000. While the Extech MA220 [$90–$110] lacks some of the Fluke 376's bells and whistles—like the ability to record maximum, minimum and average inrush currents—and has lower voltage and current ratings, it is also more compact and affordable. The Extech MA220 can measure up to 400 A ac or dc and retails for roughly one-quarter the price of a Fluke 376. The Extech EX730 [$120–$190] can measure up to 800 A ac or dc and can capture peak inrush currents and voltage transients. The Klein Tools CL2000 [$130–$150] is a 400 A clamp meter with an integrated noncontact ac voltage tester; this meter is 1,000 Vdc rated for CAT II applications.

"My most valuable tool is an Extech MA220 clamp meter with a thermocouple for making temperature measurements. This meter is small and easy to keep in my bag, and I can use it to troubleshoot the dc side of any 600 V PV system." —Bill Brooks, PE, principal, Brooks Engineering

Several survey respondents also use clamp meters with a smaller current measurement range and a correspondingly higher degree of accuracy and resolution, which is useful for verifying signals in data acquisition systems or measuring leakage current on equipment-grounding conductors. The Fluke i30 AC/DC Current Clamp [$400–$450] is a CAT III-300 V clamp that plugs into any Fluke multimeter and can measure current from 5 mA to 30 A dc, or 30 mA to 20 A ac, with a resolution of 1 mA. The Fluke 80i-110s AC/DC Current Probe (100 A) [$630–$700] is a CAT II-600 V/CAT III-300 V current clamp that plugs into a Fluke multimeter or scope and can measure current from 1 mA

Courtesy Fluke

Fluke 376 Clamp Meter with iFlex

to 100 A dc, or 1 mA to 70 A ac. Fluke's 771 Milliamp Process Clamp [$520–$550] is designed to measure current on 4–20 mA signal loops with a resolution of 0.01 mA.

Insulation resistance testers. The single most popular meter is the Fluke 1587 Insulation Multimeter [$590–$700]. Its popularity attests to the fact that insulation resistance testing is not only a critical system commissioning activity, but also useful for tracking down faults. The Fluke 1587 combines the ability to measure insulation resistance up to 50 GΩ, using 50 V, 100 V, 250 V, 500 V or 1,000 V test voltages, along with typical multimeter functionalities, including the ability to measure voltage up to 1,000 V ac or dc. Note that the Fluke 1507 Insulation Resistance Tester [$475–$525] is similar to the Fluke 1587, minus the multimeter capabilities.

Survey respondents also mentioned insulation resistance meters from Megger and Ideal Industries. For example, the Megger MIT420 [$620–$760] is a CAT IV insulation resistance and continuity tester with internal data storage for test results; it has a test voltage range of 50 V to 1,000 V and a maximum insulation resistance measurement range of 200 GΩ. At a more modest price point, Ideal's 61-795 Hand Held Insulation Tester [$300–$345] offers three test voltages (250 V, 500 V or 1,000 V) and a maximum insulation resistance measurement range of 4 GΩ.

IEC 62446, "Grid-Connected Photovoltaic Systems—Minimum Requirements for System Documentation, Commissioning Tests and Inspection," requires insulation resistance testing to be performed on PV array conductors during system commissioning. According to IEC 62446, you should determine the test voltage using the guidelines in Table 2, based on the dc system voltage (V_{oc} x 1.25). Before performing insulation resistance testing at these test voltages, isolate any surge-protection devices from the circuit you are testing and remove all other electronic equipment from the circuit. While you can use disconnects to open ungrounded conductors to inverters, you need to physically lift grounded conductors. As a result, you typically perform insulation resistance tests before landing and torquing grounded conductors.

Minimum Values for Insulation Resistance

System voltage (Voc x 1.25)	Test voltage (V)	Minimum insulation resistance (MΩ)
<120	250	0.5
120–500	500	1
>500	1,000	1

Table 2 IEC 62446 includes these minimum acceptable insulation resistance values for PV source circuits.

Always check with the module manufacturer before performing insulation resistance tests on PV source circuits. While many manufacturers are amenable to these tests, some do not approve of them. The best practice is to get the manufacturer's approval in writing. Ideally, the manufacturer can provide you with a white paper detailing its approved testing procedures.

Megger MIT400 Series insulation resistance meter

Courtesy Megger

Many EPCs perform insulation resistance tests on all the strings in a combiner box at the same time, rather than on individual strings. As a result, it can be difficult to know an exact target value for the resistance, which varies based on temperature, humidity and the number of modules you are testing. For example, as the surface area of glass increases, the expected resistance value decreases because more module-level leakage current paths are placed in parallel.

Experience is often the best guide when determining an acceptable resistance-test value range and identifying outliers. With that in mind, it is a good idea to document baseline values, which you can then use as a basis of comparison in the future. When you perform insulation resistance tests, document the test voltage, humidity, temperature and test duration so that you can perform future tests in the same manner or normalize them against these baseline CONTINUED ON PAGE 28

test conditions. If your baseline conductor temperature is 20°C and you are subsequently testing the same circuit when the conductor temperature is 30°C, you would expect the new insulation resistance measurement to be lower.

If you take insulation resistance test measurements on insulated conductors, you will find they are much higher than measurements on PV source circuits. In many cases, new conductors with good insulation peg the meter at its maximum resistance value; a minimum acceptable value is likely around 2 GΩ. Unfortunately, an acceptable test result is not a 100% guarantee against callbacks. For example, a skinned conductor in a conduit may initially test out as good; however, once moisture infiltrates the conduit, a conductive path may form between the damaged conductor and a grounding conductor, resulting in a ground fault.

Digital multimeters. While current clamps and insulation resistance testers can incorporate some of a multimeter's functions, most survey respondents also carry a general-purpose multimeter. Compared to an all-in-one meter, a dedicated multimeter often offers additional measurement functions or improved resolution and accuracy. The most popular multimeters are the Fluke 179 [$300–$320] and the Fluke 87V [about $400]. While these models have similar features, the Fluke 87V offers improved accuracy and resolution. The basic dc accuracy of the Fluke 87V is 0.05%, versus 0.09% for the Fluke 179.

> "The next-generation Seaward source-circuit tester is at the top of my commissioning tools wish list right now. I am also in the market for a torque screwdriver and an I-V curve tracer, probably the HT I-V 400."
>
> —Adam Lockert, PV service technician, Sun Light & Power

PV CHARACTERIZATION TESTERS

While you will find the meters we have discussed so far in most electrical supply houses, PV system commissioning and O&M also require some specialty electrical test equipment to

Test Leads

Having the right test leads makes taking measurements easier and safer. In the field, it is challenging to ensure that your cables and alligator clips do not devolve into a tangled and jumbled mess. Damaged test leads can compromise the integrity of your test results and, more important, your safety. Test leads are individually rated and marked according to the allowable electrical measurement category, and you must use them accordingly.


Courtesy Fluke

Fluke CAT IV test lead kit

Inspection and testing. In addition to keeping test leads organized and out of harm's way, be sure to visually inspect the test leads prior to each use and routinely test them according to the manufacturer's guidelines. An online Fluke News Plus article, "Testing Your Test Leads" (see Resources), describes the testing procedure that Fluke recommends. The procedure basically involves testing the electrical continuity of test leads using the resistance (Ω) setting of a digital multimeter. A good reading is 0.5 Ω or less, either across one lead, with both ends plugged into the multimeter, or between two leads. Since the first sign of a bad test lead is often an intermittent failure, Fluke recommends that you jiggle or shake the test leads while performing this continuity test. Intermittent failures are most likely to occur at the cable-to-connector junction.

Category rating. Using appropriately rated test leads is very important, as described in the Fluke Application Note, "Don't Risk CAT IV Areas Without the Right Leads" (see Resources). Like the weakest link in a chain, if meter leads do not have at least the same CAT rating as the meter, they can become the failure point during a test, possibly resulting in a dangerous arc flash.

According to Fluke: "[IEC] standards require that the insulation between the test lead conductor and your fingers must have the minimum distance to stand off the hazards that exist in the environment in which you are working. There should also be a finger guard on the outside of the probe that establishes the proper distance between your fingers and the exposed metal parts of the probe. These distances and insulating ratings have been predetermined for each installation category and voltage rating." ●

characterize PV modules or source circuits. The most popular products in this equipment class are commissioning and safety testers, and portable I-V curve tracers.

Commissioning and safety testers. Seaward Group USA offers a suite of testing tools specifically for PV applications. For example, the PV150 Solarlink Test Kit [about $2,000] is designed to meet the IEC 62446 commissioning test requirements. The PV150 installation tester is an all-in-one tester that verifies or measures ground continuity, insulation resistance (at 250 V, 500 V or 1,000 V), V_{oc}, I_{sc}, I_{mp} and P_{mp}. The test kit includes the Solar Survey 200R, which is basically a souped-up irradiance meter (more on irradiance meters later). The Solar Survey 200R measures real-time irradiance and temperature, and then wirelessly transmits these data back to the PV150, which can store up to 200 complete test records internally. Seaward provides USB connectivity for the data dump to PC and also offers proprietary software [about $250] for generating professional reports.

Courtesy Solmetric

Solmetric PVA-1000S I-V curve tracer

I-V curve tracers. Paul Hernday's article "Field Applications for I-V Curve Tracers" (*SolarPro* magazine, August/September 2011) provides a detailed explanation of how I-V curve tracers work and how you can use them to commission and troubleshoot PV arrays. These tools are essential for gathering data for module power warranty claims. They are also commonly used to benchmark large-scale PV system performance, to quantify the impacts of soiling and to refine plant production models over time—often at the request of project financers.

The most popular I-V curve tracers for field applications are the HT I-V 400, the Solmetric PVA-1000S and the TRITEC TRI-KA. The professionals we interviewed did not have a clear favorite, perhaps in part because each tool addresses a slightly different need based on criteria like portability, internal memory storage or battery run time. Cari Williamette, a master electrician at Ecovision Electric, notes: "If I need to power through a bunch of I-V curves to gather the data, I grab the TRI-KA; if I need to analyze curves in the field, I go with the PVA or I-V 400."

"We started off running string checks with a Fluke 1587 Insulation Multimeter. We later moved to a SolarBOS String Checker, which was safer and saved time. Most recently, we moved to the Seaward Solarlink Test Kit, which saved more time when getting the information formatted and loaded into the final report." —Dick Crafts, systems manager, Power Secure Solar

HukseefluxUSA distributes the HT I-V 400 in the US. This CAT II-1,000 Vdc meter has a maximum current measurement range of 10 A. It has a 128-by-128-pixel LCD and is sold with an external reference cell and temperature probe, which you must physically connect to the meter to capture irradiance and module temperature. The meter's internal memory capacity is 256 kilobytes, equivalent to roughly 200 I-V curves. The HT I-V 400 measures about 9.25 by 6.5 by 3 inches and weighs less than 3 pounds.

Solmetric's PVA-1000S [about $5,500] is a portable I-V curve tracer with a maximum current measurement range of 20 A. This CAT III-1,000 V meter is sold with a wireless reference sensor that measures irradiance and module temperature at a range of up to 300 feet. The primary user interface is via a laptop or tablet (not included in the kit) that communicates with the PVA-1000S using a wireless USB adapter. The largest of the three I-V curve tracers mentioned here, this unit comes with a shoulder strap for transportation. In addition to offering a higher measurement voltage range, the PVA-1000S also offers improved accuracy over the PVA-600 [about $4,700], Solmetric's 600 Vdc–rated I-V curve tracer.

The TRITEC TRI-KA [about $6,000] is available in the US via SkyBlu Energy as part of a complete kit that includes cables, sensors, sensor-mounting hardware, software and padded case. This CAT II-1,000 V/CAT III-600 V meter has a maximum current measurement range of 15 A. It has a 3.2-inch color LCD and is sold with a wireless irradiance and temperature sensor. The Secure Digital (SD) card memory storage capacity can hold more than 4,000 measurements. With physical dimensions of 8.2 by 4 by 1.6 inches and weighing in at just over 1 pound, this is truly a handheld I-V curve tracer.


Courtesy TRITEC

TRITEC TRI-KA I-V curve tracer kit

SOLAR POWER AND THERMAL TESTERS

In addition to having electrical and PV characterization testers in their tool bags, most of our survey respondents also carry an irradiance meter and an infrared (IR) camera or thermometer.

Irradiance meters. If you want to estimate real-time system performance with confidence or field-check a pyranometer in a data acquisition system, you need a handheld solar irradiance meter or pyranometer. In field applications, having laboratory-quality equipment is less crucial than having reasonably accurate, durable equipment that can stand up to local conditions.

The most popular devices are Daystar's DS-05 Solar Meter, Apogee Instruments' MP-200 and Seaward's Solar Survey 100. The Daystar DS-05 [about $160] is a compact and lightweight meter that can measure between 0 and 1,200 W/m² with an accuracy of ±3%. The Apogee MP-200 [about $410] is a pyranometer sensor with a handheld meter that displays and stores measurements; it has a measurement repeatability of less than 1% and can be used as a calibrated standard to check monitoring system sensors against. The Solar Survey 100 from Seaward is an all-in-one device that includes an irradiance meter, an inclinometer, a compass and two channels for measuring temperature.

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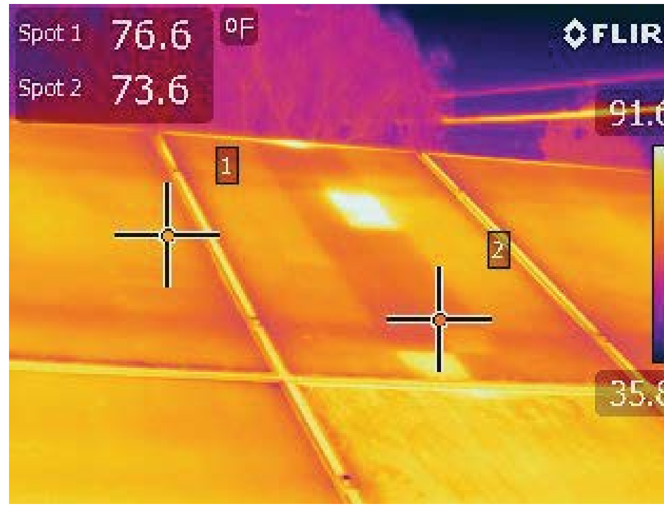
Courtesy FLIR

FLIR E60 IR camera

IR cameras. Thanks to dramatic price declines, IR cameras are more available than ever and are increasingly incorporated into standard O&M procedures for PV systems. They can identify high-resistance electrical connections and thermally stressed overcurrent protection devices. They are invaluable for locating module issues such as cracked cells, faulty internal connections and defective bypass diodes.

While there are many IR cameras to choose from, the two most popular brands are FLIR Systems and Fluke, in that order. By far the most popular model is the FLIR i7—which Bill Brooks describes as "providing the best value for your money." The other IR camera models represented are the FLIR E60, FLIR E8 and Fluke Ti200.



Courtesy Century Roof and Solar

Hot spot Tony Diaz at Century Roof and Solar was able to quickly identify this module with a toasted J-box using his FLIR IR camera.

The FLIR i7 [$1,600–$2,000] is a lightweight and compact 19,600-pixel IR camera with a 2.8-inch color LCD and microSD card storage capacity for 5,000 images. The

> "Releasable zip ties come in handy for temporarily holding things in place. I also use these or Velcro straps to organize things like a coiled-up Ethernet cable for ease of access on a future site visit."
>
> —Josh Haney, director of technical services, Next Phase Solar

FLIR E60 [$6,000–$8,000] is a 76,800-pixel thermal camera as well as a 3.1-megapixel color camera that can capture picture-in-picture composite images. It has a 3.5-inch color LCD and can output enhanced (blended) thermal images that include visual details. It also accepts telephoto and wide-angle lenses, and it stores up to 500 sets of images. The FLIR E8 [about $6,000] is a 76,800-pixel IR camera as well as a 640-by-480-pixel color camera that can capture picture-in-picture composite images. It has a 3-inch color LCD and can output enhanced thermal images with visual details. It stores up to 500 sets of images. The Fluke Ti200 [about $6,000] is a 30,000-pixel IR camera as well as a 5-megapixel visible light camera with picture-in-picture or enhanced image capabilities. It accepts different lenses, and it has video and voice recording capabilities that are useful for making notes in the field. The top-of-the-line IR cameras that utilities use run upwards of $20,000.

IR cameras are not just a significant investment in hardware. Users also require specialized technical training to accurately capture, tune and interpret thermal images. For example, FLIR recommends the thermography training services that the Infrared Training Center (ITC) offers. ITC provides three levels of thermography training and certification. Each level is a 4-day course that costs about $1,900. A 2-day day training on thermography fundamentals costs about $1,000.

Courtesy KNIPEX

KNIPEX 1,000 V insulated tool kit

> "Who knew there were so many uses for rare earth magnets? You can use them to hold placards level while adhesive dries or to fish that screw you dropped out of an underground conduit."
>
> —J.R. Whitley, owner, 690 Electric

While Level I IR Thermography Certification is a reasonable goal for most PV technicians, a basic knowledge of settings and procedures can be sufficient for using IR cameras effectively in the field. Generally speaking, you are on the lookout for outliers in the results. For example, imagine taking an IR photo of two identical conductors in the same enclosure, carrying the same current and landed identically. If one terminal measures significantly hotter than the other, a loose connection is likely the cause of the difference.

The most difficult environment for taking an accurate IR image is outside. The surface of PV module glass can reflect both the extreme heat of the sun and the extreme cold of deep space (the sky). As a result, it is a common mistake to interpret the reflection of the sun on module glass as a hot spot. Another common error is failing to compensate for the emissivity of the object you are photographing. *Emissivity* is the relative ability of a surface to radiate energy as compared to a *black body,* an idealized construct with an emissivity of 1. The emissivity of metal surfaces varies considerably, based on whether the metal is polished or coated and so forth.

Interestingly enough, black electrical tape has a known emissivity of around 0.95, so it can be valuable for making accurate temperature readings once it has reached the temperature of a surface. You can put black electrical tape on a piece of aluminum as a way of accurately setting emissivity; you can also use this technique for measuring temperature on the backsheet of a PV module. Another way to calibrate emissivity is to compare a temperature taken via a thermocouple to the IR camera temperature, and then adjust the emissivity value on the camera until the two values match. Of course, neither of these methods is suitable for use with live electrical circuits.

CONTINUED ON PAGE 36

What's in Josh Haney's Tool Bag?

As the director of technical services at Next Phase Solar—a company that provides maintenance, repair, operations and asset management services to solar power plant owners and operators—Josh Haney knows a thing or two about packing for a commissioning or O&M trip. Here are some of the tools Haney uses most.

Essentials: Computer, phone with Internet connectivity, camera, car inverter

Meters and testers: Fluke 337 600 V clamp meter (he uses a different meter for 1,000 V jobs), Fluke Ti10 thermal imager, Fluke 1587 insulation multimeter, Daystar DS-05A irradiance meter

Torque tools: Wiha Torque Control screwdriver, Craftsman torque wrenches (3/8- and ½-inch drive)

Cordless power tools: Hilti impact driver, Milwaukee reciprocating saw, vacuum

Drive sets: 3/8-inch drive socket sets (standard, deep standard, metric), ½-inch drive socket set (deep standard), hex head sockets (standard and metric), adapter for impact driver

Courtesy Next Phase Solar

Bag it, tag it Josh Haney lays out gear for a data acquisition system installation and commissioning assignment. (See *SolarPro* magazine, April/May 2013.)

Hand tools: Wiha insulated lineman's pliers, Wiha insulated Phillips screwdriver, Husky multipurpose screwdriver (similar to Klein 11-in-1), precision screwdriver, wire strippers (one for data and one for larger wire), channel locks, Cat 5 crimp tool, digital level, folding hex-key wrench sets (standard and metric), inspection mirror

Personal protective equipment: Lockout and tagout kit, Class 0 gloves with leathers, hard hat, steel-toe boots, high-visibility vest, safety glasses, sunscreen, neck shade, arc-rated pants, arc-rated shirt, insulated tools, fall protection (if working at heights), arc-flash suit (if testing energized systems)

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> "I originally bought an HT I-V 400 from Hukseflux, but later switched to TRITEC's I-V curve tracer, the TRI-KA, which measures all the way down to 1 V and can correlate temperature and irradiance data after the fact with the time-stamped I-V curves." —Tony Diaz, owner, Century Roof and Solar

IR thermometers. If you do not want to carry your $6,000 IR camera around a dusty jobsite all day but you still want to take basic IR temperature measurements, a humble infrared thermometer is just the ticket. Most of our survey respondents keep one in their tool bags or buckets at all times.

A basic IR thermometer is often nothing more than a 1- or 2-pixel, trigger-actuated thermal imaging device. These rugged and inexpensive devices are available from many manufacturers, in some cases for under $100. If you want one that runs on rechargeable lithium ion batteries, check out Milwaukee Electric Tools' Laser TEMP-GUN M12 thermometer kit [$200–$230], which has a measurement range of –30°C to 800°C. If you prefer one that matches your Fluke gear, consider the Fluke 62 MAX+ [$90–$130], with a measurement range of –30°C to 650°C.

POWER TOOLS

You should already have the heavy-duty work done come commissioning time, but you do have a lot of ground to cover in a short time. Therefore, most of our survey respondents leave their beefy power tools at home in favor of lighter and more portable products. J.R. Whitley, the owner of 690 Electric, notes: "I do miss my yellow DeWalt tools sometimes, but you can't beat Makita tools for weight. My cordless Makita kit includes an impact driver, drill, reciprocating saw, band saw and flashlight."

Haney at Next Phase Solar echoes this sentiment: "For maintenance and troubleshooting, I prefer smaller, more lightweight tools like my Hilti impact driver, which is still plenty powerful. Milwaukee makes a reasonably priced impact driver, but it is bulkier and heavier. I also carry a vacuum—for things like vacuuming metal bits out of enclosures—and leave every jobsite cleaner and safer than I found it."

DIGITAL CAMERAS

You need to carry a digital camera, but it does not need to be fancy. Nick Mshar, Strata Solar design and installation

Courtesy Salisbury by Honeywell

Salisbury Class 0 insulating rubber gloves with leathers

manager, notes: "The most valuable tool in my tool bag is a Canon PowerShot digital camera." There is no need to spend much more than $100 for a camera that will spend the bulk of its days on hot, dusty, damp or muddy jobsites. Just make sure to get a decent-size memory card, one that allows you to capture and store hundreds of high-resolution images between downloads. If you want to read the fine print on a fuse back at the office—or get your picture on the cover of *SolarPro*—you need to take images at a reasonably high resolution. If you have enough memory capacity, you can just set your camera for the highest image quality and Bob's your uncle.

Speaking of cover models, Whitley carries a Milwaukee M-SPECTOR M12 inspection camera [about $130; also offered as a complete kit with batteries for approximately $200]. He notes, "It's a plumbing tool, really, but it has come in handy for seeing in some difficult locations." The M-SPECTOR inspection camera has a 2.4-inch color LCD and a 3-foot flexible cable with a small camera head that fits inside ¾-inch openings. You can use the M-SPECTOR inspection camera to look under, over or around obstructions in tight places.

PORTABLE COMPUTING DEVICES

Most of our survey respondents consider computers indispensable for PV system commissioning and O&M. The most common field applications for computers include logging data, interfacing with data acquisition systems, troubleshooting inverters, running test and measurement device software, generating customer reports, and downloading equipment manuals or plan set details. Not everyone we surveyed relies on a computer in the field, however. For example, Strata Solar's Mshar reports, "I keep my computer out of the field; it is most valuable to me in the office."

"My most valuable tool is an Asus laptop computer, which I use for inverter troubleshooting, system analysis and information retrieval."
—Johnnie Little, QA/QC manager, LightWave Solar Electric

Haney at Next Phase Solar uses a computer on every job. He explains: "At a minimum, we are logging what we did to generate a report for the customer. I also make it a habit to take screenshots so that I can reference them later, especially if I am doing something for the first time or making changes to a program. The application-specific programs that I regularly use in the field include proprietary inverter and tracker software, Campbell Scientific's LOGGERNET datalogger support software, Modbus Poll, Fluke thermal imaging software and Solmetric PVA software. I also use general-purpose programs like Microsoft Office, Adobe Acrobat and Image Resizer for Windows."

Top 10 Butt-Savers

- LED headlamp
- Jumper wire
- Inspection mirror
- Rare earth magnets
- Irwin Quick-Grip clamps
- Right-angle screwdriver set
- Picquic Stubby screwdriver
- Picquic Teeny Turner
- Tiny Tim hacksaw
- 5-gallon bucket swivel seat


Courtesy David Del Vecchio

Don't be blindsided Inspection mirrors are an invaluable commissioning tool, useful for spotting incorrect hardware or stray conductor strands.

While most survey respondents carry Windows-based laptops, several use tablets from Samsung or Apple. The obvious benefit of carrying a native Windows device is that most specialty software programs are designed to run on that platform. If you want to take your expensive MacBook into the field, you need software like Parallels Desktop for Mac, which allows you to run both Windows and OS X applications simultaneously on your Mac.

If you are taking your computer into the field, you likely also need some means of Internet connectivity, such as a Wi-Fi hotspot on your phone. To get more than a few hours' work out of your wirelessly connected cell phone and computer, be sure to pick up a 12 Vdc to 120 Vac inverter for your car or truck. While you are at it, pick up spare batteries for all of your new meters.

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David Brearley / *SolarPro* magazine / Ashland, OR / david.brearley@solarprofessional.com / solarprofessional.com

RESOURCES

"ABCs of Multimeter Safety," Fluke Application Note, fluke.com

"Testing Your Test Leads," Fluke News Plus, fluke.com

"Don't Risk CAT IV Areas Without the Right Leads," Fluke Application Note, fluke.com

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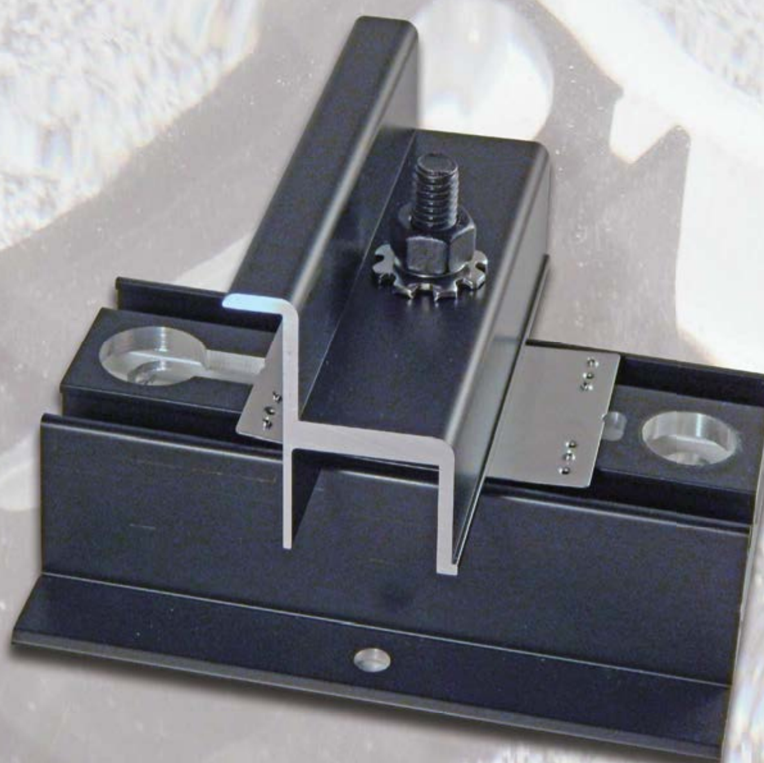

SOLAR POWER INTERNATIONAL 13

Solar Power International 2013

Future-Proof
Strategies for Success

By David Brearley

The solar industry's goal has always been to fundamentally change the US energy delivery industry. It was clear in Chicago that the industry is succeeding. However, with greater power comes greater responsibility.

"Welcome to the big leagues." Solar Energy Industries Association (SEIA) President and CEO Rhone Resch repeated this phrase several times in his opening remarks to attendees at Solar Power International (SPI) 2013, suggesting both how far the solar industry has come in a relatively short time and the importance of performing at a high level to have staying power. Resch elaborated: "We've gone from being an 'upstart industry'—one that our critics predicted would fail miserably—to [being] one of the fastest-growing industries in the United States."

When SEIA and the Solar Electric Power Association (SEPA) first collaborated to present a solar industry conference in 2004, the installed annual US grid-tied PV capacity was 58 MW. By comparison, SEIA and GTM Research estimate that more than 4.4 GW of new PV capacity will be connected to the US utility grid by the end of 2013. In addition to achieving this impressive 62% compound annual growth rate, solar power became the second leading source of new US energy generation capacity through the first three quarters of 2013, outperformed only by natural gas.

Resch's opening remarks highlighted many remarkable industry milestones and accomplishments:

- The US solar industry currently employs more than 120,000 people at more than 6,000 companies.
- For the second year in a row, the country's top commercial solar consumer is Walmart, with more than 89 MW of PV capacity installed at 215 locations.
- Thanks to a grassroots campaign, solar energy is helping to power the White House.

Welcome to the big leagues, indeed.

While the solar industry clearly has many mainstream accomplishments to celebrate, Resch also cautioned that nothing comes easy in the big leagues. "Groups all across the country," he warns, "are lined up to oppose an expansion of solar energy." These groups include electric utilities, conservative think tanks and politicized organizations. Resch continued: "Simply put, our critics will do everything they can to make sure solar becomes nothing more than a footnote in history. We cannot let that happen. So buckle up and tighten your chin straps, folks—we've got a lot of big challenges ahead of us."

For this article, I interviewed industry stakeholders and thought leaders to look at two of the big challenges facing the solar industry: utility integration, and system safety and performance. Though not directly related to one another, these challenges both shaped the look and feel of SPI 2013, and the industry's own success, its move from the margins to the mainstream, amplifies their scope. Further, the technological responses to these challenges will fundamentally change the way we design and deploy grid-interactive PV systems in the future. Since big challenges tend to create opportunities, I also

Courtesy Solar Power International

Courtesy GreenLancer

Best start-up business plan SPI 2013 featured the first ever Start Up Alley Challenge, a pitch competition for up-and-coming companies with business plans aimed at reducing industry soft costs. Cloud-based engineering services provider GreenLancer won the inaugural competition in a unanimous decision.

highlight with images some interesting new products and services my colleagues and I came across in Chicago, especially those that address industry pain points.

Utility Integration

With regard to utilities, the most pressing challenge facing the US solar industry likely relates to the general assault on net-metering programs across the country. While this is discouraging, most of the experts I interviewed believe that utilities will ultimately embrace distributed solar resources. It is also increasingly evident that new technical requirements and emerging technologies promise to vastly improve the solar industry's value proposition for utility operators and customers.

NET METERING

In January 2013, the Edison Electric Institute (EEI), an organization representing approximately 200 investor-owned utilities, published the white paper "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business." This is an interesting read for anyone in the solar industry, as the report outlines "recent technological and economic changes that are expected to challenge and transform the electric utility." According to Peter Kind, the executive director of Energy Infrastructure Advocates and the author of the EEI report, the biggest threat to electric utilities nationwide comes from distributed generation (DG) and distributed energy resources (DER), most notably PV systems, with demand-side management and energy efficiency programs running a close second.

"The financial implications of these threats are fairly evident," writes Kind. "Start with the increased cost of supporting a network capable of managing and integrating distributed generation sources. Next, under most rate structures, add the decline in revenues attributed to revenues lost from sales foregone. These forces lead to increased revenues required from remaining customers (unless fixed costs are recovered through a service charge tariff structure), which are sought through rate increases. The result of higher electricity prices and competitive threats will encourage a higher rate of DER additions, or will promote greater use of efficiency or demand-side solutions."

If you have ever wondered why some electric utilities resist the proliferation of distributed solar generation, Kind succinctly spells out one of their major concerns. Electric utility analysts have done the math on the falling cost curve for PV systems versus the rising cost curve for utility rates and concluded that the potential exists for a vicious cycle: As more customers install solar or implement efficiency measures, utilities will have to increase rates to make up for decreasing revenues; however, as rates increase, there is more incentive for consumers to go solar or implement efficiency measures. Kind concludes by recommending a series of immediate and long-term actions intended to protect the traditional utility business model from disruptive forces.

Anyone who pays attention to solar energy policy news has seen the effects of the immediate actions electric utilities have taken in response to the EEI report. According to SEIA's Resch: "Since that report was published, utility CEOs around the country have been singing from the same song sheet: Roll back net metering, institute fixed monthly charges for solar customers and protect us from consumer choice. They are aligned in their approach to dismantling net metering laws in this country."

Power in numbers. With net metering and solar tax fights brewing across the country—including in Arizona, California, Colorado, Georgia, Louisiana and Minnesota—it is vital for the industry to present a united front. If your company is not already a member, there has never been a better time to join SEIA or one of the state or regional SEIA chapters. As an individual, you can engage groups like Vote Solar and The Solar Foundation, and encourage your customers to do the same. "Fortunately," says Resch, "we are not in this fight alone. Today, 90% of Americans want to see an expanded use of solar." He concludes, "It's time for utilities to start listening to their customers rather than their shareholders."

Carl Siegrist is a renewable energy strategist based in Wisconsin who served for nearly a decade on the SEPA board of directors. Siegrist notes: "In the not-too-distant past, most utilities viewed distributed solar—if they viewed it at all—as an expensive solution that would have little impact on their business. A handful of utilities saw solar power's potential to defer distribution costs in high-growth areas, and a few were marginally interested from an R&D perspective through their participation in EPRI [Electric Power Research Institute]. Even today, legislative or regulatory requirements drive the majority of utility support for solar. I don't think any utility planners envisioned the level of cost reductions we've seen over the past decade or the widespread interest in solar by so many customers. Some of us in the solar industry said solar had the potential to become a very disruptive technology everywhere 'someday.' That day is upon us."

Siegrist continues: "Now that the utility industry generally recognizes that solar has the potential to impact its financial bottom line, many are trying to find ways to slow the adoption of distributed solar. Solar power should not be a political issue, but with groups like the American Legislative Exchange Council leading a coordinated fight to dismantle clean energy legislation across the United States, it is beginning to get politicized. This is unfortunate, and the tactics we're seeing will fail. Note the alliance between the Tea Party and the Sierra Club in Georgia, where utility regulators recently voted against a proposed solar fee. In my state, Wisconsin, CONTINUED ON PAGE 44

Annual SPI Attendance Vs. US PV Capacity

SPI year	Registered attendees	Exhibitors	Location	Annual US grid-tied PV capacity
Solar Power 2004	1,150	60	San Francisco Hyatt Regency	58 MW
Solar Power 2005	1,250	66	Washington, DC, Hyatt Regency	79 MW
Solar Power 2006	6,500	160	San Jose Convention Center	105 MW
Solar Power 2007	9,500	210	Long Beach Convention Center	160 MW
Solar Power International 2008	17,500	425	San Diego Convention Center	298 MW
Solar Power International 2009	24,000	929	Anaheim Convention Center	435 MW
Solar Power International 2010	23,300	1,122	Los Angeles Convention Center	848 MW
Solar Power International 2011	21,000	1,200	Dallas Convention Center	1,887 MW
Solar Power International 2012	15,000	900	Orange County Convention Center, Orlando	3,313 MW
Solar Power International 2013	13,000	600	McCormick Place, Chicago	4,400 MW (est.)

Belt tightening? The recent disconnect between annual SPI attendance and installed PV capacity is surprising—until you factor in the average PV system price declining by more than 40% since the beginning of 2011, impacting company revenue available for conference registration. Look for attendance to rise in 2014 as SPI heads to Las Vegas.

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Courtesy Schneider Electric

UL-listed at 1,000 Vdc Schneider Electric was one of several central inverter manufacturers to introduce listed 1,000 V central inverters for the North American market in 2013. The Conext Core XC-NA, shown here, is an outdoor-rated model with advanced smart-grid capabilities.

the Libertarians have endorsed Renew Wisconsin's proposal to allow third-party solar leases. Distributed solar is a clean energy choice issue, it is a property rights issue, and yes, it is an environmental issue as well."

Tobin Booth is the CEO of Blue Oak Energy, a solar electric engineering and construction company headquartered in Davis, California. In the long run, Booth expects that the utilities that embrace DG will outperform those that resist it. He explains: "Utilities can either see DG as a threat or as an opportunity. The utilities that are entrepreneurial and embrace DG as an opportunity will ultimately be the utilities that dominate the energy delivery industry in the US. In the past, energy consumers wanted reliability only. Now they want choice. How can the US utility industry give their customers what they want? DG is the answer."

Embracing the win-win proposition. "I am always sad to hear when the solar and electric industries perceive themselves to be at odds," says Sarah Kurtz, a principal scientist at NREL. "On one hand, fossil fuel prices won't always be stable. So if utilities are looking out for their ratepayers, they benefit from establishing a portfolio of technologies that will isolate the ratepayers from the risk of volatile fuel prices. On the other, without the utilities to keep the electrons flowing when the sun sets, the public wouldn't find solar to be as attractive. The solar and electric industries should work together as partners to find mutually beneficial solutions, recognizing the benefits of distributed solar as well as the challenges of maintaining a stable and equitably financed grid—then we would *all* win as solar grows even faster."

Interestingly, the EEI report concludes with a telling sense of inevitability: "Ultimately, all stakeholders must embrace change in technology and business models to maintain a viable utility industry." Transformative changes are coming, and electric utilities clearly feel threatened. However, these changes do not render the existing utility infrastructure obsolete, as happened with the telephone industry. "In the telecom situation," the report's author explains, "the original copper wire phone network is of no to little value in a wireless, Internet protocol, landline world. However, the value of the electric grid to the customer is retained in a DG environment as the grid provides the highway to sell power generated by the DER and the backup resource infrastructure to deliver power required when DER is not meeting the load obligation of its provider."

Since utility companies make up approximately half of SEPA's membership, SEPA President and CEO Julia Hamm has a unique perspective on this issue: "Underlying the glamour of solar is a lot of necessary infrastructure. And like the infrastructure that supports our cell phones, it carries a cost. We are just at the beginning of figuring out how to measure and fairly assign the costs of that infrastructure in a world that includes significant distributed resources. Infrastructure may be boring and often out of sight. But it is, nevertheless, critical."

Hamm concludes: "As the electric utility business heads into historic, perhaps revolutionary transformation, it could benefit from becoming more entrepreneurial, more agile and open to change—to see the customer value proposition a bit more like solar companies do. And as solar companies work to stabilize their businesses for growth, they may do well to look at how solar needs to be part of a sustainable, long-term and complete provider of reliable energy—to become a bit more like a utility."

NET BENEFIT

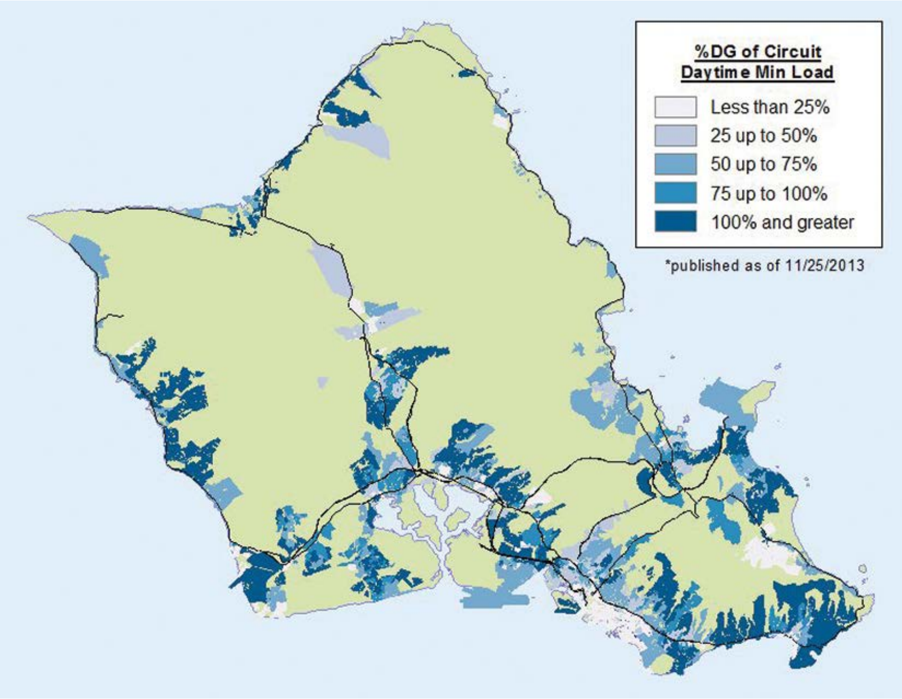
To overcome utility opposition, the solar industry must improve the value proposition associated with inverter-based generators and eliminate concerns about solar resource variability. The collaborative effort to finalize smart inverter rules for California is a step in the right direction, as these rules will help standardize future utility interconnection requirements. Further, the California Public Utility Commission (CPUC) recently announced a grid-scale energy storage target that will enable the state to integrate more solar capacity in the future.

Smart-grid inverter rules. While not a main-stage topic at SPI 2013, the redesign of California's Rule 21, which describes interconnection, operating and metering requirements for distributed generators, was a hot topic with inverter manufacturers and regulatory compliance specialists. The Smart Inverter Working Group (SIWG), which the CEC and the CPUC formed as a joint effort in early 2013, is preparing the Rule 21 revisions and expects to have them finalized by February or March 2014. Pilot testing in the field is scheduled to begin as soon as the revisions are finalized.

The Rule 21 revisions are intended to facilitate high DG penetration by requiring that inverter-based DER be able to perform an array of smart-grid functions not currently allowed under UL 1741. These advanced inverter capabilities include low/high voltage and frequency ride-through; autonomous, dynamic reactive-power injection; emergency ramp rates; and soft-start methods. While it is not uncommon for inverters in large PV power plants to provide these smart-grid capabilities, Rule 21 will mandate that all grid-connected inverters provide these capabilities, perhaps as early as October 2015.

"Utilities have some legitimate concerns about adding variable renewable inputs to the utility grid," notes Rudy Wodrich, the vice president of solar at Schneider Electric. "These concerns include the inherent intermittent nature of renewable generation sources and how these sources integrate into grids, which were typically designed for load flow in just one direction—from the central generation plant to the consumer. However, well-designed PV power plants that incorporate inverters with the necessary grid-interactive features as well as energy storage can also provide many valuable functions and services that utility operators want. These soft benefits include helping to reduce voltage sags during fault events, providing reactive-power control for midterm voltage regulation, as well as both short-term voltage and frequency-regulation support via active power injection or absorption."

According to Wodrich, the lack of a common national interconnection standard is one of the biggest obstacles to preventing utilities and the solar industry from working together effectively right now. If that is true, then the importance of the smart-inverter rule-making process in California is self-evident. When it comes to PV equipment testing and certification requirements, as California goes, so goes the nation (as is often the case). Rule 21 revisions will impact all inverter manufacturers active in or wishing to access the growing US market. While the revision process is somewhat contentious, it is undoubtedly proof that the solar industry is rapidly maturing and moving to the mainstream.



Courtesy Hawaiian Electric Company

High DG penetration Electric utilities in Hawaii are already confronting the challenges of operating an electric grid with a high penetration of variable energy resources. This map of distribution circuits in Oahu is published by the Hawaiian Electric Company and shows the percentage of DG relative to the daytime minimum load.

ENERGY STORAGE

The opportunity for grid-scale and commercial-scale energy storage solutions represents one of the most intriguing trends to emerge in 2013. Initially, new energy storage subsidies in Germany generated much of the energy storage buzz. However, it is clearly an emerging market in the US, and one that has implications for solar solution providers.

In October 2013, the CPUC announced that it had set an energy storage target of 1.325 GW for the state's three largest investor-owned utilities. One of the stated goals is to optimize California's electrical grid for integrating more renewable resources, including solar. In a high-penetration scenario, grid operators worry that an overreliance on variable energy resources can undermine grid stability and reliability. Affordable grid-scale energy storage can solve this problem because it can be dispatched instantaneously on demand to compensate for short-term solar resource variability.

While high renewable penetration may seem far off in many markets, it is already a reality in places like Puerto Rico and Hawaii. At SPI 2013, Schneider Electric announced that it was partnering with energy solutions provider Fonroche to build Puerto Rico's largest PV power plant. To meet the utility's minimum technical requirements for grid stability, the 40 MW PV power plant will incorporate a utility-scale battery bank and a medium-voltage capacitor bank. The power plant controller will allow utility operators to send commands to the solar inverters and the energy storage system. According to Wodrich, "We believe our experiences in Puerto Rico provide a glimpse into what the future utility grid will look like in a high renewable penetration scenario."

At the commercial scale, more and more energy service and technology companies are building business models around their ability to reduce utility demand charges for customers. This is another complementary application for solar and energy storage. By themselves, grid-interconnected PV systems can reduce customers' energy charges, but peak demand savings come into play once they add an energy storage component. According to Ash Sharma, the senior research director for solar at IHS, PV energy storage installations in North America are expected to grow annually by 190% on average for the next 5 years.

System Safety and Performance

As the solar industry grows, it also comes under increasing scrutiny from firefighters, code-making entities and investors. According to Kurtz at NREL, the PV industry faces many technical challenges as it scales: "The industry must eliminate the risk of causing fires, as well as overcome firefighters' fears of fighting fires on buildings equipped with PV systems. At the same time, the industry must achieve low costs while ensuring that durability is adequate to meet warranty performance in a range of climates, and control quality management systems to ensure consistent quality."

While this does not make for sexy main-stage fare, it does make for meaty technical sessions, and event organizers report record-breaking attendance at these sessions. The conference offered many interesting educational tracks in Chicago (for example, business growth and development, finance solutions, integration with utilities, and policy and regulations), as well as popular concurrent sessions in the operations, performance and maintenance track. One of these sessions, "Fire Safety: Update and Impact of Code Changes," dealt specifically with fire safety issues and their impact on electrical and building codes.

FIRE SAFETY

There are two main considerations regarding fire safety in PV systems. The first is that PV systems, like all other electrical systems, have the potential to cause a fire. New arc-fault protection requirements and improved ground-fault detection and mitigation schemes address this issue. The second consideration is that the presence of a PV system may exacerbate a fire caused by an external source, either by spreading the fire or by hampering firefighter efforts to extinguish it.

Arc-fault protection. While fires initiated by or involving PV systems are rare, when they occur they often attract a disproportionate amount of negative publicity. According to the Fraunhofer Institute for Solar Energy Systems, approximately 0.006% of the 1.3 million PV systems in Germany have caused a fire resulting in significant damage. While these data suggest that PV systems are no more dangerous than traditional electrical systems, "every fire is one too many," concludes Dr. Heribert Schmidt, a project leader at Fraunhofer.

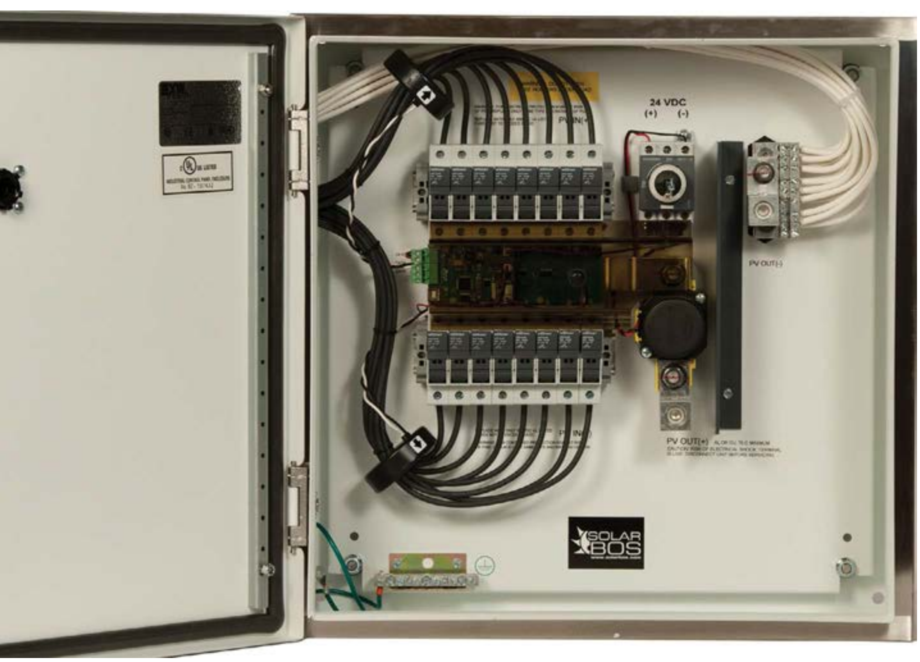
In instances where PV systems or components have initiated a fire, the root cause is typically some sort of arcing fault. Three types of arcing faults can occur in PV power circuits: series arc faults, parallel arc faults and arcing ground faults. Parallel arc faults are the most difficult to mitigate of the three, and little evidence shows these are causing problems in the field. Series arc faults and arcing ground faults, however, have caused PV failures that lead to fires. The solar industry has generally pushed back on efforts to require parallel arc-fault protection for PV systems and has backed expanded protection requirements for series arc faults.

Series arc-fault requirements. Series arc faults indicate a failure in continuity in a conductor, connection, module or other system component. Installation errors and damaged or faulty system components are the most likely causes of a dc arc fault. The *NEC* 2011 cycle of revisions added series arc-fault protection requirements in Section 690.11. These requirements apply to PV systems with a maximum system voltage over 80 Vdc that are mounted on a building or have dc conductors entering a building. However, *NEC 2014,* which was officially released in October 2013, expands series arc-fault requirements to *all* PV systems operating above 80 Vdc.

With California poised to adopt *NEC 2011,* the dc arc-fault requirements have implications for many industry stakeholders. Manufacturers need to ensure that they can continue to sell products to the largest domestic PV market. System integrators and product distributors need to make sure that they do not wind up with warehouses full of stranded inventory. Last but not least, AHJs need to get up to speed on the new requirements and decide how to enforce them.

While dc arc-fault protection will eventually become a standard feature in PV modules, string inverters or source-circuit dc combiner boxes, only a few products offer this functionality today. For example, SMA America has integrated arc-fault protection into a specific subset of its North American string inverter models; Fronius USA offers integrated arc-fault protection in its IG Plus Advanced models; and SolarBOS released the industry's first listed arc-fault protection combiner boxes at SPI 2013. Since systems designed using module-level power electronics typically have a maximum system voltage of less than 80 Vdc, the arc-fault protection requirements in *NEC* Section 690.11 generally does not affect them.

Ground-fault detection and mitigation. While *NEC* Section 690.5 requires ground-fault protection for all grounded PV arrays, a highly publicized PV system fire in Bakersfield, California, revealed a potential problem with the protection strategy used for some listed central inverters. (See "The Bakersfield Fire: A Lesson in Ground-Fault Protection," *SolarPro* magazine, February/March 2011.) Investigators looking into the cause of the Bakersfield fire determined that the ground-fault protection equipment used in a large central inverter



Courtesy SolarBOS

Arc-fault combiners At SPI 2013, SolarBOS released the industry's first line of listed arc-fault detection and arc-fault circuit-interruption combiners.

had likely failed to detect a ground fault in a grounded PV source-circuit conductor. They coined the term *ground-fault protection blind spot* to describe the issue.

A working group convened by the Solar America Board for Codes and Standards (Solar ABCs) subsequently confirmed the existence of a ground-fault detection blind spot and concluded that the deficiency is inherent in many commercial-scale PV systems in the US. Furthermore, the potential fire hazard will only increase as these systems age.

In 2013, Solar ABCs published a pair of reports related to the issue: "Inverter Ground-Fault Detection 'Blind-Spot' and Mitigation Methods" and "Analysis of Fuses for 'Blind-Spot' Ground Fault Detection in Photovoltaic Power Systems." (See Resources.) The mitigation strategies and equipment retrofit options described in these reports are most relevant for fleet operators and O&M providers.

Blind-spot mitigation strategies range from simple and inexpensive retrofit options ("reduce the ground-fault fuse size") to complex and costly solutions more suitable for inverter manufacturers ("install residual current detector on positive and negative array wiring and connect to inverter emergency stop input"). According to the Solar ABCs report, "Early results from large PV systems that have been retrofitted with the recommended protective devices indicate that these devices can substantially reduce the detection blind spot without requiring redesign of the system."

Going forward, changes to product safety standards and *Code* revisions will eliminate the ground-fault detection blind spot from new systems. For example, Section 690.5, "Ground-Fault Protection," was extensively revised for *NEC 2014.* New language in 690.5(A)(1) clarifies that ground-fault protection equipment must be capable of detecting faults in intentionally grounded conductors.

Fire class rating for PV systems. Motivated by new language in the *2012 International Building Code (IBC),* SolarABCs has been engaged in a 5-year effort to develop a fire classification rating for roof-mounted PV systems. *IBC* Section 1509.6.2 states, "Rooftop-mounted photovoltaic systems shall have the same fire classification as the roof assembly as described in UL 790." This is a meaningful change because existing products standards classify the fire rating for PV modules separately from the fire rating for roof coverings. In effect, the *2012 IBC* requires evaluation of the roof covering, the PV mounting system and the PV modules together as a system.

To merge requirements from UL 790, "Standard Test Methods for Fire Tests of Roof Coverings," and UL 1703, "Flat-Plate Photovoltaic Modules and Panels," UL needed to develop a new fire test method. Christopher Flueckiger, the UL principal designated engineer for renewable energy, was a presenter for the fire safety session in Chicago. Flueckiger reported that the fire test revisions to UL 1703 would likely be available for comment in the weeks following the conference.

Firefighter safety. Less than 2 months before the solar industry convened in Chicago for SPI 2013, a refrigerated warehouse in Delanco, New Jersey, that hosted a 1.6 MW roof-mounted PV system burned to the ground. Because the 11-alarm fire happened on a holiday weekend, no one was injured. Chief Ron Holt of the Delanco Fire Department explained that the presence of the PV system influenced his decision to let the building burn: "With a normal roof, we would be able to get on there, trench it, cut it off and stop it at a certain point. With the power sitting up on that roof, that building is not worth one of my guy's life."

That scenario has long been a concern in the PV industry. Three years ago, I interviewed John Berdner, now the director of global regulatory compliance at Enphase Energy, for an article about module-level power electronics. (See "Distributed PV System Optimization," *SolarPro* magazine, August/September 2010.) Berdner warns: "In Germany there have been fires that firefighters let burn because of the high-voltage dc wiring on the roof. Imagine if anything similar were to happen in the US. If firefighters won't fight the fire, then insurance companies won't insure the property. This is one of the reasons that I believe intelligent modules are both necessary and inevitable."

According to San Jose Fire Department Fire Captain Matthew Paiss, who regularly provides solar electric safety training to fire service personnel, firefighters have two main concerns when it comes to buildings equipped with PV systems:

Class A fire rating Both Trina Solar and SolarWorld introduced glass-on-glass (instead of glass-on-film) PV module lines in 2013. These dual-glass products generally offer improved structural characteristics, a better long-term power warranty and a Class A fire rating.

Courtesy Trina Solar

First, they may require roof access to perform *ventilation,* a strategy used to remove heat and smoke from a building. Second, they need to be able to fight fires without putting themselves at risk of electric shock hazards. Firefighters ultimately want PV systems that they can safely shut down in the event of an emergency.

Roof access. The California State Fire Marshal developed the first roof-access requirements for PV installations in 2008. (See Resources.) Other states and AHJs adopted the "Cal Fire" requirements, and both the *2012 International Fire Code* and the 2012 edition of the *NFPA 1: Fire Code* subsequently incorporated them. If your AHJ does not yet enforce these requirements, your company can still adopt them as design guidelines.

Courtesy AE Solar Energy

System-level savings AE Solar Energy released 1,000 Vdc versions of its existing 3-phase, transformer-less string inverters at SPI 2013. The new AE 3TL 1000 Series inverters use an ungrounded PV array and provide BOS cost reductions due to longer strings, fewer home runs and lower resistive losses.

Mitigating shock hazards. The *NEC* addresses PV system shock-hazard mitigation for firefighters. For example the 2011 cycle of revisions extensively modified Section 690.31(E). To reduce the chance that firefighters will come into contact with energized dc PV power circuits located within a building, installers must now locate dc circuits at least 10 inches below a roof deck, protect them with "substantial guard strips" if they use flexible metal conduit, and permanently mark and label them.

While steps like these can reduce shock hazard, they do not eliminate it. Paiss explains: "PV systems built to current standards are the only electrical systems found on buildings that untrained personnel cannot turn off. The safe shutdown of PV systems is not only the biggest concern that firefighters have, but it is also the most difficult to implement."

Emergency shutdown. While it will add cost and complexity to implement, it is possible to enable safe shutdown of PV systems. New language in *NEC 2014* represents the industry's first attempt to eliminate hazards associated with energized dc conductors on top of and traveling through buildings. Section 690.12 describes new rapid-shutdown requirements that apply to PV source- and output-circuit conductors that run more than 5 feet inside a building or more than 10 feet outside the PV array area. Contactor combiner boxes and module-level power electronics will meet these rapid shutdown requirements.

The emergency shutdown requirements in *NEC 2014* represent a significant compromise between firefighters and the solar industry. What firefighters ultimately want are touch-safe PV modules. As originally written, Section 690.12 required module-level shutdown capabilities for many PV systems. The compromise version of Section 690.12 in *NEC 2014* gives the solar industry a few more years to develop and perfect module-level solutions. The 2017 cycle of revisions to the *Code* will almost certainly add module-level shutdown requirements.

COST VS. PERFORMANCE

Evolving safe shutdown requirements are one manifestation of a bigger challenge facing the solar industry, which is how to drive costs down without compromising performance. On one hand, module-level power electronics can make touch-safe PV modules a reality and improve energy yield (kWh/kW); on the other, module-level power electronics add cost, complexity and potential failure points to PV systems. Falling module prices are another example of cost versus compromise. Circa 2007, the average selling price for a PV module was roughly $3.50 per watt; today, it is less than $0.70 per watt. These dramatic price declines have led to increasing concerns about module reliability and quality. (See "Industry Perspectives on c-Si PV Module Reliability and the Rise of Comparative Testing," *SolarPro* magazine, October/November 2013.)

According to Kurtz at NREL: "Ultimately, I think the biggest challenge is to balance our desire to reduce costs with the benefit of creating modules we are confident will last decades." Since 2011, the International PV Module Quality Assurance Task Force—which includes NREL and other industry stakeholders—has been working to develop comparative accelerated testing standards. The goal is to establish a technical basis that investors and financers can use to qualify and compare products, technologies and projects.

Kurtz elaborates: "The IEC [International Electrotechnical Commission] has just formed a new conformity assessment board, which held its first meeting the week before SPI. This new board will oversee quality of renewable energy systems, including PV and wind. The overall goal is to raise the confidence in PV quality to be similar to the confidence we expect of the automotive or aerospace industries. This goal will not be achieved overnight, but the International PV Module Quality Assurance Task Force and many other organizations will help the IEC move quickly toward this goal."

Whereas declining PV module and inverter prices have largely made possible the dramatic PV system cost reductions in recent years, further cost reductions in the near future are more likely to come from business process improvements and system-level design approaches. For example, the US Department of Energy and the Rocky Mountain Institute published a report in August 2013 (see Resources) that provides a road map for reducing PV system soft costs, such as costs associated with installation labor, permitting, interconnection, customer acquisition and financing. While improvements in BOS components still promise meaningful hardware cost reductions, system-level design approaches—like the innovative efforts of the HDPV Alliance—offer more significant cost savings potential.

The photos in this article highlight examples of products and services from SPI 2013 that address soft or system-level costs. To learn more about a company's unique value proposition, check out its website. While you are at it, put the details for SPI 2014 on your calendar: The conference is heading back west and will be held at the Las Vegas Convention Center, October 20–23. See you in Vegas!

CONTACT

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RESOURCES

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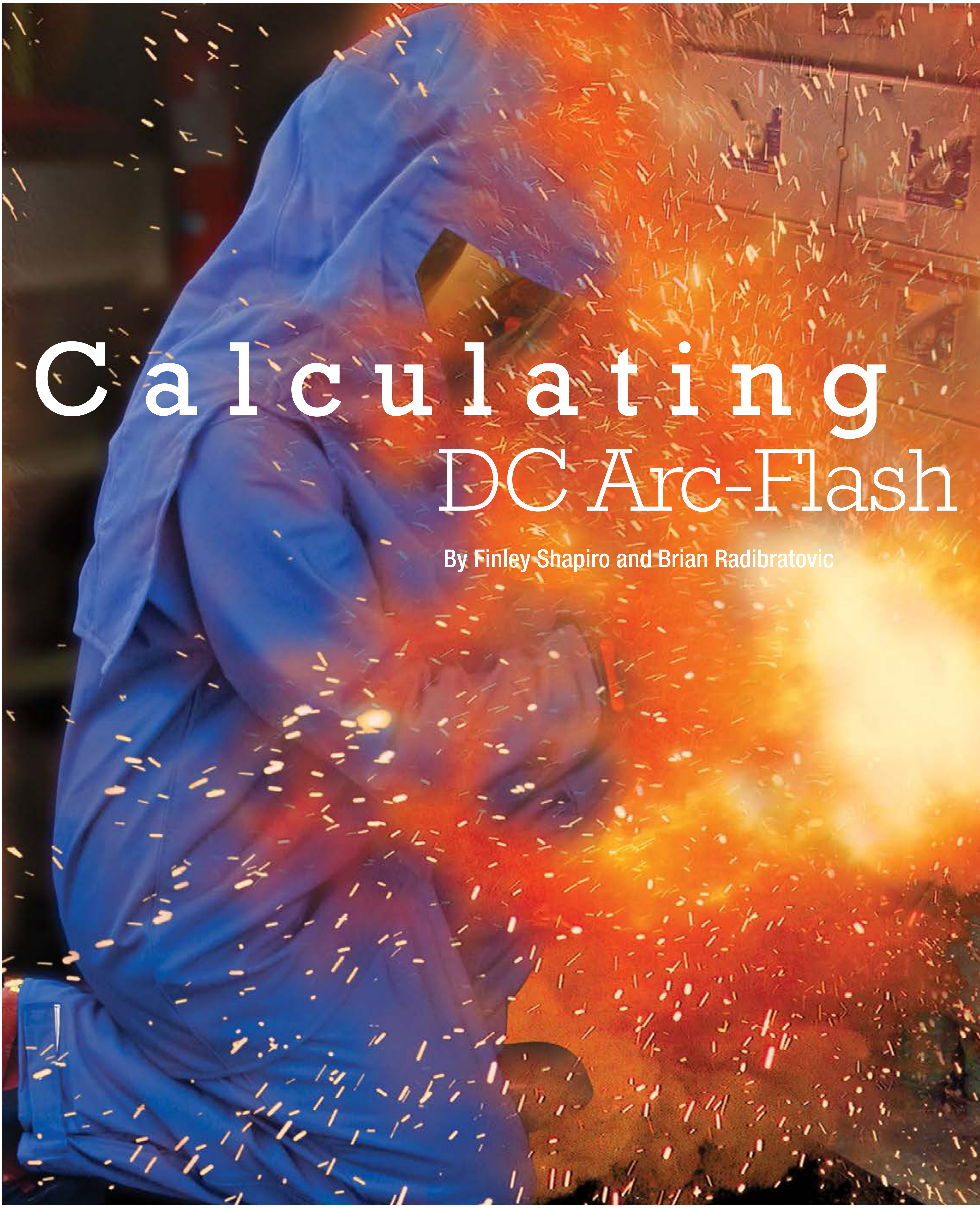


Calculating DC Arc-Flash

By Finley Shapiro and Brian Radibratovic

Courtesy Salisbury by Honeywell

In large commercial and utility-scale PV systems, hundreds or thousands of PV modules are connected in series and parallel. The combined dc output power potential at aggregation points, including combiner boxes, recombiner boxes or inverter-input combiner compartments, is often higher than 1 MWdc. In addition, dc voltages may approach 1,000 V and current levels may exceed 1 kA. **While a system is energized, failures or human error during commissioning, testing and troubleshooting can cause arc-flash events that severely injure or even kill technicians.**

Hazards in PV Systems

In this article, we propose a method to calculate the incident energy on the dc side of a PV system. You can use the results to identify and label arc-flash hazards and to select personal protective equipment (PPE). We also discuss practical considerations for protecting workers from dc arc-flash hazards.

ARC-FLASH EVENTS

An *arc-flash event* is the release of energy caused by a line-to-line or line-to-ground fault. During an arcing fault, electrical energy is transformed into other forms of energy such as heat and pressure. *Arc flash* refers to the intense light created by the electrical arc. An *arc blast* is the explosive release of energy—characterized by intense sound pressure and vaporized metal—that normally accompanies an arc flash.

The risks. Common testing and commissioning procedures require technicians to clamp or measure energized circuits at multiple locations on the dc side of the system, including combiner and recombiner boxes, disconnect switches and inverters, putting them at risk for arc-flash events. DC arc flashes can expose workers to temperatures as high as 35,000°F. Due to the rapid release of large amounts of energy, individuals who have had the misfortune of being close to an arc-flash event have lost their lives or suffered severe physical trauma including hearing loss, blindness and high-degree burns. According to the Informative Annex K of the 2012 *NFPA 70E: Standard for Electrical Safety in the Workplace* (*NFPA 70E*), "the majority of hospital admissions due to electrical accidents are from arc-flash burns, not from shocks, and arc flashes can and do kill at distances of 3 m (10 ft)." Informative Annex K also notes that arc blasts can expel material and molten metal "away from the arc at speeds exceeding 1,600 km/hr, fast enough for shrapnel to completely penetrate the human body."

Possible causes. Several conditions can cause an arc-flash event, including accidental contact within or across an electrical system made by a tool or individual; buildup of conductive dust; corrosion; improper use of equipment; or loose splices or terminations. Under any of these conditions, a line-to-line or line-to-ground fault can result in a dangerous arc-flash event.

UNDERSTANDING THE HAZARD

NEC Section 110.16 requires that electrical equipment "likely to require examination, adjustment, servicing, or maintenance while energized shall be field marked to warn qualified persons of potential electric arc-flash hazards." Informational Note No. 1 refers users to *NFPA 70E* for assistance in "determining severity of potential exposure, planning safe work practices, and selecting personal protective equipment."

NFPA 70E Article 100 defines *arc-flash hazard* as "a dangerous condition associated with the possible release of energy caused by an electric arc." Section 110.3(F) requires that "an electrical safety program shall include a hazard identification and a risk assessment procedure to be used before work is started within the limited approach boundary or within the arc-flash boundary of energized electrical conductors and

Courtesy Max Isaacs/690 Electric

DC arc-flash hazards During system testing and commissioning, workers are commonly exposed to arc-flash hazards in combiner boxes, recombiner boxes and inverters.

circuit parts operating at 50 V or more or where an electrical hazard exists."

Arc-flash hazard analysis. *NFPA 70E* Section 130.3(B)(1) requires that an arc-flash hazard analysis be conducted prior to exposing workers to energized electrical parts or circuits operating at or above 50 V if workers cannot be placed into an electrically safe working condition. Section 130.5 states that an arc-flash hazard analysis must determine "the arc-flash boundary, the incident energy at the working distance and the personal protective equipment (PPE) that people within the arc-flash boundary shall use."

Incident energy is the energy measured on a surface at a specified distance from the arc-flash location. In particular, it is the heat energy per unit area that an individual could be exposed to. You calculate incident energy values for a specified distance from the blast. IEEE Standard 1584 lists a standard distance of 455 mm (45.5 cm or approximately 18 inches) for these calculations. Per *NFPA 70E,* the arc-flash boundary for systems operating at or above 50 V is the distance at which the incident energy equals 5 J/cm^2 (1.2 cal/cm^2). Exposure to incident energy equal to or greater than this value can cause second-degree burns, and a person entering the arc-flash boundary needs to wear appropriate PPE.

Per *NFPA 70E* Section 130.5(B)(1), an incident energy analysis calculates "the incident energy exposure of the worker (in calories per square centimeter) ... based on the working distance of the employee's face and chest areas from a prospective arc source for the specific task to be performed." You can use the resulting incident energy value to define the arc-flash boundary and select the PPE for the task you are performing. *NFPA 70E* Section 130.7 defines arc-flash requirements for proper PPE selection. Workers must wear appropriately rated PPE within the arc-flash boundary. Note that a technician's hands may be closer to the hazard than the face and body.

In lieu of performing an arc-flash hazard analysis and the associated incident energy analysis, *NFPA 70E* Section 130.5(B)(2) permits use of the requirements from Sections 130.7(C)(15) and 130.7(C)(16) "for the selection and use of personal and other protective equipment." Tables 130.7(C)(15)(a) and (b) define the hazard/risk category (HRC) for various tasks. The tables list multiple tasks with defined parameters or assumptions with an associated HRC based on the voltage, available short-circuit current and fault-clearing time. The tables also specify whether the task at hand requires insulated gloves and tools. Bear in mind that the increased incident energy at shorter working distances may require gloves with a higher arc-flash rating than the rest of the PPE.

Table 130.7(C)(16) has five categories: 0–4. The most stringent category, HRC 4, specifies arc-rated clothing with a minimum rating of 40 cal/cm^2. Table 130.7(C)(16) may be used with HRCs determined by Table 130.7(C)(15)(a) or (b) only and not with other incident energy calculations. When Table 130.7(C)(15)(b) does not clearly define the tasks and parameters of the work—as in most PV applications—it is best to conduct an incident energy analysis for a dc application.

Ultimately, an incident energy analysis helps ensure that technicians are properly protected against an arc-flash event. It provides the maximum incident energy in calories per square centimeter, the same value used to rate PPE. Although HRC 4 from Table 130.7(C)(16) requires PPE with a minimum rating of 40 cal/cm^2, equipment ratings can be as high as 100 cal/cm^2. Arc-flash PPE kits may include a coat, bib overalls, over pants, a hood, a hard hat, safety glasses and gloves. Additional PPE includes coveralls, coats, shirts, pants, undergarments, hairnets, beard restraints, boots, earplugs, face shields and goggles. (See "Selecting Arc-Flash PPE.")

Labeling arc-flash hazards. Per *NFPA 70E* Section 130.5(C), electrical equipment installed in locations other than dwellings "likely to require examination, CONTINUED ON PAGE 56

Selecting Arc-Flash PPE

Arc-flash PPE selection is based on the incident energy analysis or the hazard/risk category (HRC) for the task you are performing, as defined by *NFPA 70E* Table 130.7(C)(15)(b). The HRC categories indicate the level of protection required for the hazard present and the fire-resistant rating required for the protective gear. The technician must use all PPE in conjunction to ensure protection from the three distinct hazards that can occur during an arc-flash event: fire, bright light and intense sound. Improper use of PPE or underrated PPE can expose a worker to any of these hazards, possibly resulting in serious injury or death. Table 1 outlines required PPE for HRC 0–4.

In addition to using PPE, workers should wear clothing that does not melt or conduct electricity. Synthetic materials such as nylon, polyester and Lycra can bond to the skin if exposed to high temperatures—even when an adequately fire-rated outer garment protects the wearer.

Courtesy Salisbury by Honeywell

HRC 4 PPE kit. This technician is using an HRC 4 kit and insulated tools from Salisbury by Honeywell.

Proper care is important to keep PPE ready for service. If any part of the equipment is damaged or worn, you should remove it from service and replace it. You must wash clothing in accordance with the manufacturer's instructions. Stains or contamination from solvents can affect the garment's rating. Not all safety gear is rated for arc flash, so it is important to confirm that all components are properly rated. Many safety suppliers and manufacturers offer complete arc-flash PPE kits and can also help in selecting the proper equipment. Insulated tools and properly rated shock protection gloves are also considered electrical PPE, and workers should use them whenever they are performing tasks on live circuits of more than 50 V.

—Karl Riedlinger / independent PV safety professional / karlriedlinger@gmail.com

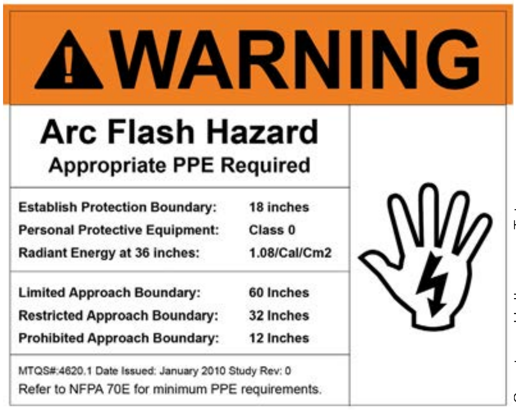
Table 1: PPE Required for HRC 0–4

Hazard/risk category (HRC)	Minimum arc rating (cal/cm²)	Arc-rated clothing	Protective equipment
0	N/A	Protective clothing with nonmelting or untreated fiber at least 4.5 oz/yd; long-sleeve shirt, long pants (does not have to be arc rated); gloves	Safety glasses or goggles, hearing protection, heavy-duty leather gloves (as needed)
1	4	Coveralls or long-sleeve shirt and long pants; face shield or arc-flash suit hood; gloves; jacket, parka, rainwear or hard hat liner (as needed)	Hard hat, safety glasses or goggles, hearing protection, heavy-duty leather gloves, leather work shoes (as needed)
2	8	Coveralls or long-sleeve shirt and long pants; balaclava and face shield or arc-flash suit hood; gloves; jacket, parka, rainwear or hard hat liner (as needed)	Hard hat, safety glasses or goggles, hearing protection, heavy-duty leather gloves, leather work shoes (as needed)
3	25	Long-sleeve shirt; long pants; coveralls; arc-flash suit jacket; arc-flash suit pants; arc-flash suit hood; gloves; jacket, parka, rainwear or hard hat liner (as needed)	Hard hat, safety glasses or goggles, hearing protection, heavy-duty leather gloves, leather work shoes
4	40	Long-sleeve shirt; long pants; coveralls; arc-flash suit jacket; arc-flash suit pants; arc-flash suit hood; gloves; jacket, parka, rainwear or hard hat liner (as needed)	Hard hat, safety glasses or goggles, hearing protection, heavy-duty leather gloves, leather work shoes

adjustment, servicing, or maintenance while energized shall be field marked with a label." This applies to combiner and recombiner boxes, dc disconnect switches, and inverters where technicians measure and test energized dc circuits. Per *NFPA 70E* Section 130.5(C), the label must contain this information:

(1) At least one of the following:
 a. Available incident energy and the corresponding working distance
 b. Minimum arc rating of clothing
 c. Required level of PPE
 d. Highest HRC for the equipment
(2) Nominal system voltage
(3) Arc-flash boundary

Furthermore, *NFPA 70E* Section 130.5(C) specifies that "the method of calculating and data to support the information for the label shall be documented." Ideally the PV plan set details calculations and results so that technicians have the information prior to beginning construction. This allows them to develop safety plans and obtain the necessary PPE before beginning work.



Courtesy HellermannTyton

Arc-flash hazard labeling You must label enclosures where workers may be exposed to an arc-flash hazard according to *NFPA 70E* 130.5(C). Labels like this from HellermannTyton warn workers of such hazards so they can properly protect themselves.

ASSESSING THE HAZARD ON THE DC SIDE

For dc applications, *NFPA 70E* Table 130.7(C)(15)(b) covers tasks up to 600 Vdc only, so it cannot be used for large-scale PV systems that operate above 600 Vdc. Likewise, all PV systems that operate under 600 Vdc may not meet the parameters included in the table. Section 130.7(C)(15) states: "[For] tasks not listed, or for power systems with greater than the assumed maximum short-circuit current capacity or with longer than the assumed maximum fault-clearing times, an incident energy analysis shall be required in accordance with 130.5."

To help ensure that workers are adequately protected, in Informative Annex D the *NFPA 70E* presents methods for calculating incident energy. Informative Annex D.8.1 covers dc arc-flash calculations and references two methods. The first is referred to as the *maximum power method.* Daniel Doan, who presented this method at the 2007 IEEE Electrical Safety Workshop (see Resources), assumes that the maximum power possible in a dc arc occurs when the arcing voltage is 50% of the system voltage. However, the assumption that the maximum power for a dc arc occurs when the arcing voltage is half the system voltage is not valid for PV systems in our opinion.

The second method is based on a thorough theoretical review of dc arcing current and energy as presented at the 2009 IEEE Petroleum and Chemical Industry Committee (PCIC) Conference. See the 2009 paper "DC-Arc Models and Incident-Energy Calculations" for detailed calculations (see Resources). Given that this approach is based on empirical data, it may not accurately calculate incident energies for working conditions in large-scale PV systems.

In the recent article "Arc-Flash Hazards on Photovoltaic Arrays," David Smith from the Colorado State University's Department of Electrical and Computer Engineering concluded, "[Currently,] no consensus standard exists for calculating arc energies in dc systems" (see Resources).

SUGGESTED ARC-FLASH HAZARD CALCULATION

The *NFPA 70E* does not exclude the use of alternative methods for calculating incident energy and the corresponding arc-flash boundary, and studies are under way to better quantify dc arc-flash hazards. In this article, we suggest one alternative approach.

We base our proposed calculations of incident energy on the methods in *NFPA 70E* Informative Annex D and the IEEE Standard 1584-2002 "Guide for Performing Arc-Flash Hazard Calculations" (see Resources). We use work distances and exposure times that are standard for arc-flash calculations, and we assume proper fuse sizing and operation.

The basic equation. We calculate the incident energy of an arc-flash hazard as the possible power of an arc, multiplied by the time a person might be exposed to the arc flash, divided by the area over which the energy is spread. If the arc's thermal energy is spread over the surface of a sphere at a specified distance, then the incident energy is equal to the total thermal energy divided by $4\pi D^2$, such that:

$$IE = P_{arc} \times T_{exp} \div (4\pi D^2)$$

CONTINUED ON PAGE 58

where *IE* is the incident energy, P_{arc} is the maximum possible power feeding the arc in kilowatts, T_{exp} is the exposure time and *D* is the distance from the arc. However, when the arc occurs in an enclosure—such as a combiner box, recombiner box, disconnect switch or inverter—the incident energy is concentrated in one direction rather than spreading uniformly. In this case, after you have calculated the spherical incident energy, *NFPA 70E* Informative Annex D.8.1.1 advises: "[It] would be prudent to use a multiplying factor of 3 for the resulting incident energy value." Thus, we calculate the incident energy for an arc flash that occurs inside an enclosure as:

$$IE_{enc} = P_{arc} \times T_{exp} \div (4\pi D^2) \times 3$$

Now we determine the appropriate input values.

P_{arc}: Per *NEC* Section 690.8(A)(1), a PV source circuit's maximum current is calculated as 125% of the rated Isc. Furthermore, the maximum current for a PV output circuit is the sum of the currents from the parallel source circuits that combine to form it, as calculated in *NEC* Section 690.8(A)(1). Thus, the *NEC* assumes that the current within a source circuit or output circuit could exceed the circuit's Isc rating by 25%.

Given the direct relationship between current and power, it is reasonable to assume that the power in a source circuit and corresponding output circuit could also exceed its STC rating by 25%. Therefore, we apply a factor of 1.25 to the rated power (P_{max}) for each source circuit that could contribute power to an arc-flash event.

As shown in Figure 1, the output power a source circuit or output circuit delivers depends on the load resistance. When properly sized per the *NEC,* source-circuit and output-circuit conductors carry the full short-circuit current of the circuit with minimal resistance. Thus, we assume that in an arc fault the load resistance is the resistance of the arc itself—nothing more. Unfortunately there is no good way to predict this resistance. As a worst-case scenario, we assume that resistance within the circuit does not decrease P_{arc}.

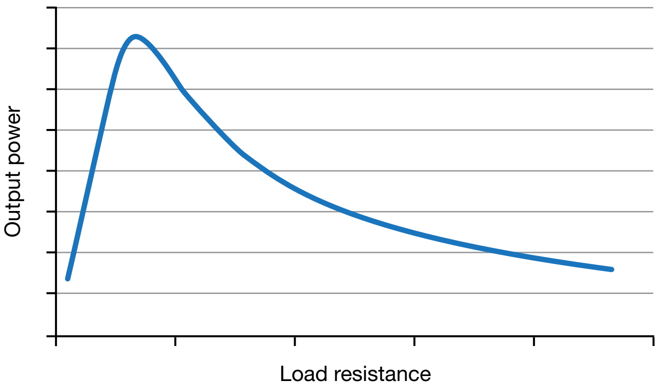


Figure 1 The shape of the output-power curve for a PV source or output circuit varies as a function of the load resistance into which the power flows. The scale of either axis depends on the module characteristics and the number of modules connected in series.

T_{exp}: The time of exposure is either the time until a protective fuse blows and ends the arc-flash event, or the maximum time a person is expected to remain in contact with the arc flash until moving away. *NEC* Section 690.8(B)(1)(a) requires that source-circuit and output-circuit overcurrent protection devices (OCPDs) be sized to "carry not less than 125% of the maximum currents calculated in 690.8(A)." The additional 25% accounts for "continuous operation." Thus, under "normal operating conditions," the OCPDs may not open. Under these conditions, an individual's exposure time is determined by how quickly he or she moves away from the hazard. Assuming that egress is not inhibited, the maximum exposure time is assumed to be 2 seconds. Both IEEE Standard 1584-2002 and *NFPA 70E* Informative Annex D agree that an individual exposed to an arc flash will move away as quickly as possible, and that 2 seconds is a reasonable maximum exposure time.

D: IEEE Standard 1584-2002 recommends a working distance of 45.5 cm (approximately 18 inches) for low-voltage motor control centers and panelboards (Section 4.8, Table 3). You should calculate the incident energy for all possible distances (in centimeters) at which workers, or their body parts, may be exposed to an arc-flash event.

Conversion factors. Since P_{arc} and T_{exp} are measured in watts and seconds, respectively, we need to make a conversion to find the resulting incident energy in calories per square centimeter. One joule equals one watt-second. To convert the resulting value into calories, we included a conversion rate of 0.239 calories per joule. We added a second conversion factor of 1,000 W/kW to the equation since P_{arc} is measured in kilowatts. The resulting equation for the potential incident energy from a dc arc-flash event in an enclosure is:

$$IE_{enc} = P_{arc} \times T_{exp} \div (4\pi D^2) \times 3 \times 0.239 \text{ cal/J} \times 1{,}000 \text{ W/kW}$$

CALCULATING INCIDENT ENERGY ON THE DC SIDE

Figure 2 shows a common electrical design for the dc side of a grounded PV system with two levels of combiner boxes feeding one inverter. In such designs, each source circuit typically consists of 10 to 20 crystalline modules connected in series with an open-circuit voltage between 400 Vdc and 1,000 Vdc, and an output power rating of 2 kW–5 kW.

This design shows an example of a negatively grounded PV system. The same calculations can be used to calculate the arc-flash hazard for positively grounded and non-isolated PV systems in which neither leg is grounded.

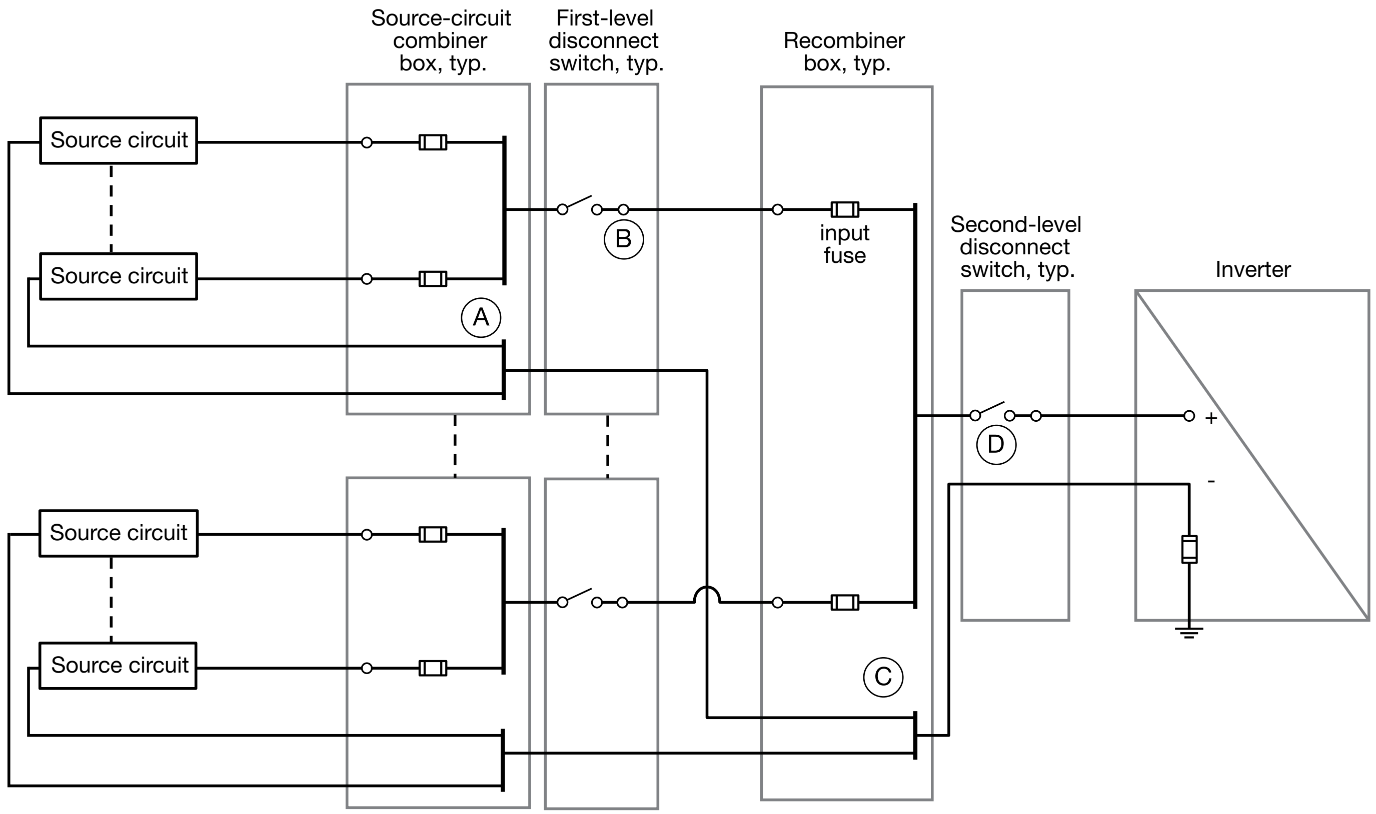


Figure 2 This single-line diagram shows a generalized electrical schematic for a negatively grounded nonresidential PV system with two levels of combiners and disconnects. The incident energy at each component is based on the distance from the arc flash, the length of exposure and the amount of available power.

The first level of source-circuit combiner boxes combines the inputs from individual source circuits into one output circuit. In this design, the output circuits are located between the source circuits and the inverter. They are recombined at the second-level recombiner boxes prior to feeding the inverter. In the example, each combiner box aggregates an equal number of source circuits with the same P_{max} ratings, meaning the power ratings are equivalent for each enclosure within the varying levels.

The source-circuit combiner boxes and recombiner box have an associated disconnect switch on the output circuit. To review the features and benefits of dc-combining equipment and strategies, see "DC Combiners Revisited," *SolarPro* magazine, February/March 2011.

Source-circuit combiner boxes combine as many as 52 source circuits typically operating below 20 Adc. Recombiner boxes are usually used with higher-capacity central inverters to combine as few as two or as many as 20 output circuits, and they can have a combined output greater than 1,000 Adc. Depending on the system, dc voltages in these enclosures may approach 1,000 V. Due to the higher current levels, recombiner boxes present an increased arc-flash hazard compared to source-circuit combiner boxes.

In this design, an arc-flash event is most likely to occur as an electrical fault between positive and negative conductors, busbars or terminals inside a first- or second-level combiner box or disconnect. Possible causes include mechanical failure, cracked or compromised insulation, or metallic objects that are dropped or placed across energized parts. All too often, arc-flash events are due to human error, such as a technician inadvertently introducing a conductive path between live parts while conducting commissioning or O&M procedures.

Point A. We begin by evaluating an arc-flash event at the source-circuit combiner box, assuming the first-level disconnect switch is securely in the open position. We calculate P_{arc_a} as:

$$P_{arc\_a} = P_{box} \times 1.25$$

where P_{box} is the rated power connected to the source-circuit combiner box at Point A, and 1.25 accounts for power levels exceeding the rated values by 25%.

In this example, since we assume the first-level disconnect switch to be open, we do not need to consider backfeed power from other output circuits. If the switch were closed, we would need to calculate these additional power sources, and the sum of the two incident energy values would dictate the required warning labels and PPE.

Using P_{box}, we can express the incident energy calculation for a source-circuit combiner box as:

$$IE_a = (P_{box} \times 1.25) \times T_{exp} \div (4\pi D^2) \times 3 \times 0.239 \text{ cal/J} \times 1{,}000 \text{ W/kW}$$

Assuming a working distance of 45.5 cm (approximately 18 inches) and an exposure time of 2 seconds, we can calculate the incident energy at Point A as:

$$IE_a = P_{box} \times 1.25 \times 2 \text{ sec} \div (4 \times \pi \times (45.5 \text{ cm})^2) \times 3 \times 0.239 \text{ cal/J} \times 1{,}000 \text{ W/kW}$$

This simplifies to:

$$IE_a = P_{box} \times 0.069 \text{ cal/cm}^2\text{/kW} \quad [1]$$

If a source-circuit combiner box combines 10 source circuits in parallel—each with a maximum power rating equal to 4,000 W—P_{box} is 40 kW, such that:

$$IE_a = 40 \text{ kW} \times 0.069 \text{ cal/cm}^2\text{/kW}$$

$$IE_a = 2.8 \text{ cal/cm}^2$$

This is the incident energy at a distance of 45.5 cm (approximately 18 inches) from the arc-flash event. The incident energy increases with proximity: Any body parts that are closer to the arc could be exposed to a higher incident energy and should be protected accordingly.

Point B. Now consider the energy available at the first-level disconnect switch while it is in the open position. The incident energy at point B due to backfeed current from the recombiner box could exceed the incident energy calculated for Point A. Thus, we must calculate the incident energy from an arc flash powered by potential backfeed currents. Note that if the disconnect switch were closed, this same backfeed incident energy would be possible at Point A. When in the open position, the first-level disconnect switch isolates this potential backfeed power source from the source-circuit combiner box located at Point A.

Current flowing back from the recombiner box can contribute to an arc-flash event at Point B. (See Point B in Figure 2, p. 59.) Note that the size of the input fuse in the recombiner box limits the amount of current that can flow back to Point B.

Per *NEC* Section 690.8(B)(1)(a), PV source circuit and output circuit OCPDs are sized an additional 25% larger than the maximum rated current as calculated by *NEC* Sections 690.8(A)(1) and (2). Furthermore, *NEC* Section 240.4(B) allows use of the next higher standard overcurrent device rating when selecting a fuse size of 800 A or less. These factors increase the rating of the OCPD relative to the rated current of the circuit for which it was sized.

If at least two other source-circuit combiner boxes are connected to the recombiner box located upstream from Point B, given the variable and current-limited nature of PV production, the currents from the other source-circuit combiner boxes could combine and flow backward through the input fuse corresponding with Point B without clearing it. This is the case even if the input fuses are properly sized per *NEC* Articles 690 and 240.

Thus, P_{arc} at Point B is greater than it was at Point A, yet limited by the amount of current—and thus power—the input fuse allows to backfeed the arc. Once again, assuming a direct relationship between current and power, we can apply the multipliers used to size the OCPD based on a circuit's Isc to P_{arc}. Since P_{arc} is a multiplier of IE, we can apply that multiplier directly to the incident energy equation from Equation 1, such that:

$$IE_b = IE_a \times 1.25 \times 1.2 \div 0.9$$

where 1.25 accounts for the additional 125% potential backfeed current flow allowed by the oversized input fuse per *NEC* Section 690.8(B)(1)(a); 1.2 accounts for the possible roundup to the next larger fuse size allowed per *NEC* Section 240.4(B); and 0.9 is the ratio of the maximum power current to the short-circuit current. Thus, if we limit our calculation of incident energy to the case where we are below the power at which the fuse blows, we find that the incident energy at Point B is 67% larger than at Point A:

$$IE_b = IE_a \times 1.67$$

Given $IE_a = P_{box} \times 0.069$ cal/cm²/kW, we can express IE_b as:

$$IE_b = P_{box} \times 0.069 \text{ cal/cm}^2\text{/kW} \times 1.67$$

$$IE_b = P_{box} \times 0.115 \text{ cal/cm}^2\text{/kW} \quad [2]$$

This incident energy is possible even under moderate sunlight conditions if at least two other source-circuit combiner boxes can contribute power to the arc.

If the first-level disconnect is closed, current can reach Point A or Point B from modules connected to both the source-circuit combiner box and its associated recombiner box. The possible arc-flash incident energy at each location is the amount the recombiner box can backfeed as calculated in Equation 2, plus whatever the source-circuit combiner box can contribute under the conditions in Equation 1. Thus, the total resulting incident energy is:

$$IE_{tot} = IE_a + IE_b$$

$$IE_{tot} = (P_{box} \times 0.069 \text{ cal/cm}^2\text{/kW}) + (P_{box} \times 0.115 \text{ cal/cm}^2\text{/kW})$$

$$IE_{tot} = P_{box} \times 0.184 \text{ cal/cm}^2\text{/kW} \quad [3]$$

Note that potential incident energy is reached only when irradiance conditions cause the source circuits connected to the combiner box to output maximum power *and* the design of the other sections of the array will generate 1.67 times the power at the combiner box under the same conditions. Equation 3 represents an upper limit that many system designs may not reach.

Points C and D. If all of the dc disconnect switches are closed, the possible incident energy available at Points C and D in Figure 2 (p. 59) is equal to the power of all of the PV modules connected to the inverter, P_{array}, multiplied by 0.069 cal/cm²/kW:

$$IE_{c,d} = P_{array} \times 0.069 \text{ cal/cm}^2\text{/kW} \quad [4]$$

Large PV systems commonly use 500 kW inverters with dc-to-ac sizing ratios as high as 1.4, in which case the available arc-flash incident energy could be as high as 48.3 cal/cm².

$$IE = 500 \text{ kW} \times 1.4 \times 0.069 \text{ cal/cm}^2\text{/kW}$$

$$IE = 48.3 \text{ cal/cm}^2$$

Note that higher-capacity inverters are increasingly common in utility-scale applications, and thus incident energy values on the dc side of a PV system are likely to exceed 50 cal/cm².

These calculations assume that all fuses are present where required, are sized correctly and interrupt fault current as intended. If the recombiner box is missing an input fuse, or a fuse is oversized or does not interrupt a fault current, the incident energy at the source-circuit combiner box and disconnect switch would be significantly larger than calculated due to the backfeed from other source-circuit combiner boxes connected to the recombiner box.

SUMMARY OF RESULTS

Table 2 summarizes the equations in this article. While the results are based on the system described in Figure 2, you can use the general methodology as a model for other PV system designs. Be aware that the available arc-flash incident energy in larger systems varies based on the inverter's dc bus configuration. Also note that dc arc-flash studies

55 cal/cm² PPE. This jacket and bib overalls from Salisbury by Honeywell are only two of the multiple PPE items required to protect workers from arc-flash hazards. Salisbury offers complete PPE kits rated up to 100 cal/cm².

Courtesy Salisbury by Honeywell (2)

Table 2: Calculating Incident Energy

Location in Figure 2 (Point)	Disconnect switch open or closed?	Maximum incident energy equation at 45.5 cm (18 in)	Arc-flash boundary (cm)
A	open	$P_{box} \times 0.069$ cal/cm²/kW	$11 \times \sqrt{P_{box}}$
B	open	$P_{box} \times 0.114$ cal/cm²/kW	$14 \times \sqrt{P_{box}}$
A or B	closed	$P_{box} \times 0.184$ cal/cm²/kW	$18 \times \sqrt{P_{box}}$
C or D	closed	$P_{array} \times 0.069$ cal/cm²/kW	$11 \times \sqrt{P_{array}}$

Table 2 You can use the equations in this table to calculate incident energy at various points in a PV system. The equations assume a fault clearing time of 2 seconds and a distance from the arc-flash event of 45.5 cm (approximately 18 inches). P_{box} and P_{array} are measured in kilowatts.

Calculating Incident Energy Using the Maximum Power Method

When calculating incident energy, the greatest magnitude of fault current does not always describe the worst-case scenario. It is necessary to consider all possible operating scenarios and provide a worst-case scenario for each potential hazard area in the system. Therefore, the arc-flash hazard analysis method typically includes calculations for maximum and minimum contributions of fault-current magnitude. The minimum calculation assumes that the source contribution is at a minimum. Conversely, the maximum calculations assume a maximum contribution from the source and assume that all motors—if any exist at the solar site—are operating at full-load conditions.

Depending on the PV system size, an arc-flash hazard analysis may require incident energy and boundary calculations for a variety of locations on the dc side of a PV system. For example, Eaton Corporation recently performed a study on a utility-scale PV system that involved nearly 50 arc-flash hazard locations. In the analysis, Eaton used the following parameters to replicate a PV power source:

- System voltage was modeled at 100% of the rated maximum power voltages (V_{mp}) at STC, assuming a cell temperature of 25°C. System voltage was considered constant, as different ambient temperatures are not typically modeled.
- Short-circuit current (I_{sc}) was treated as variable based on the irradiance, as shown in the commonly published PV module I-V curves.
- Short-circuit currents (I_{sc}) from the PV modules were modeled using dc chargers configured as constant current sources.
- Short-circuit currents (I_{sc}) were modified by changing the constant current values of each dc charger to reach the maximum 2-second clearing time of each fuse.

The incident energy associated with a dc arc-flash event depends upon these factors: the maximum bolted fault short-circuit current available at the equipment; system voltage; the total protective device clearing time (upstream of the prospective arc location) at half of the maximum short-circuit bolted fault current, per *NFPA 70E;* and the distance of the worker from the arc-fault hazard.

Per *NFPA 70E* Informative Annex D.8.1.1, you can calculate dc incident energies using the maximum power method as follows:

$$I_{arc} = 0.5 \times I_{bf}$$
$$IE_m = 0.01 \times V_{sys} \times I_{arc} \times T_{arc}/D^2$$

where I_{arc} is the arcing current (A); I_{bf} is the system-bolted fault current, based on I_{sc} (A); IE_m is the estimated dc arc-flash incident energy at the maximum power point (cal/cm^2); V_{sys} is the system voltage, based on V_{mp} (V); T_{arc} is the arc time (sec); and D is the working distance (cm).

Per Informative Annex D.8.1.1 in *NFPA 70E,* you should apply a multiplication factor of 3 to incident energy values occurring in a box or enclosure such that:

$$IE_m = 0.01 \times V_{sys} \times I_{arc} \times 2/D^2 \times 3$$

—Will Aydelotte / Senior Power Systems Engineer / Eaton Corporation / eaton.com

for the voltage and current ranges utilized in PV systems are under way at the Institute of Electrical and Electronics Engineers (IEEE). The results of these IEEE studies will likely facilitate more-accurate calculations of dc arc-flash hazards in PV systems.

Our calculations suggest that commercial and utility-scale PV systems can present significant dc arc-flash hazards. Avoiding injuries from arc-flash events requires proper PPE, safe working procedures and safety training. You should routinely include calculations of arc-flash hazards at different locations in the design of PV arrays with ratings greater than 10 kW, following a standardized set of procedures. In addition, all combiner boxes, recombiner boxes, transition boxes, dc disconnect switches and inverter dc input compartments should have warning labels specifying the maximum incident energy and PPE requirements. Electrical schematics should note arc-flash hazards, and the same information should appear prominently in record documents that go from the designer to the individuals who install, own, monitor and maintain a PV system.

ARC-FLASH HAZARD SAFETY CONSIDERATIONS

The safest approach to arc-flash hazard safety is to avoid working near energized equipment. Conducting incident energy calculations and complying with *NFPA 70E* PPE and labeling requirements can only partially mitigate the risks when equipment is energized. Here are some of the most critical issues to consider when designing, installing and servicing PV systems:

1) You must do some electrical testing while the PV system is operating, such as measuring voltages and currents inside source-circuit combiner boxes. To reduce the potential incident energy from an arc-flash event where you are conducting tests, open any first- and second-level disconnect switches for combiner boxes that are not under test. Always use lockout and tagout procedures to ensure that equipment remains de-energized, but remember that arc-flash hazards may still exist even when disconnect switches are in the open position.

Courtesy Sun Light & Power

Potential incident energy in a source-circuit combiner box This combiner box contains 31 source circuits. Assuming each source circuit has a P_{max} of 3 kW, the incident energy in this box—excluding any potential backfeed power—would be 6.5 cal/cm^2 (IE = 93 kW × 0.069 cal/cm^2/kW = 6.5 cal/cm^2).

2) Limited space inside an enclosure and a large number of conductors can make measuring and testing circuits inside a source-circuit combiner or recombiner box quite challenging. Although a translucent cover protects live parts and hazardous areas in source-circuit and recombiner boxes, technicians often remove the shield to take measurements or to use a clamp meter on individual input and output conductors. This often requires pulling an energized

A clamp meter for tight spaces The Fluke 365 True-rms AC/DC Clamp Meter has a detachable jaw that measures 200 A ac or dc. The thin, small detachable jaw is great for measuring source-circuit and output-circuit conductors in combining enclosures.

Courtesy Fluke Corporation

conductor into place to get the clamp around it, which is a dangerous task. Stress on terminations could loosen the connection, and a conductor could potentially come loose and cause an arc-flash event.

In addition to considering the size of a combining enclosure, when making terminations, carefully arrange conductors so you can easily access and measure them. Select testing equipment that does not compromise the technician's safety.

3) Most commercial and utility-scale PV systems use inverters rated 250 kW or higher, which are commonly fed by recombiner boxes. However, some systems use a distributed design approach that utilizes multiple string inverters aggregated on the ac side of the system. This design substantially reduces the maximum dc arc-flash hazard at any location in the system compared to installations using large central inverters.

4) Make sure you install, maintain and update arc-flash hazard warning labels as needed. Many PV systems are not operated by the companies that built them, so technicians often do not have access to the information they require to calculate arc-flash hazards before going to a site. Even while on-site, they may not be able to make the necessary calculations.

5) Design errors such as incorrect fuse sizes or the absence of necessary overcurrent protection can increase arc-flash hazards. Always verify that OCPDs are properly rated and deployed prior to calculating the potential incident energy for a given hazard.

6) Testing and maintaining PV systems often requires climbing ladders, walking near roof edges, working in hot locations and other situations where wearing heavy PPE can be a substantial burden. Employers can give workers the necessary PPE, but adverse work conditions may cause technicians to not use it. Training and educating workers about the hazards and risks presumably increases the likelihood of their using the necessary gear rather than cutting corners.

7) Service technicians sent to diagnose underperforming or offline systems may encounter a variety of unforeseen risks, including one or multiple faults, damaged equipment or other unsafe conditions. To prepare work processes, safety plans and PPE accordingly, workers must always assume the worst-case scenario—namely, that all conductive parts are energized and that equipment may contain potentially dangerous faults.

8) Some companies offer third-party arc-flash hazard analyses or software programs that calculate incident energy and arc-flash boundary by location on a given project. Some of these software programs can custom-print warning labels for arc-flash hazards.

CONTACT

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Brian Radibratovic / Power Analytics Corporation / San Diego, CA / bradibratovic@poweranalytics.com / poweranalytics.com

RESOURCES:

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SWITCHboard

From the Forum

Module Warranty Limitations

The following discussion is from a recent thread on *SolarPro*'s technical forum. Visit *solarprofessional.com/forum* to post questions or join the conversation.

Original post from Terence:
One of our installation crewmembers recently walked over a solar panel and the glass cracked. Is this covered by warranty? Per the manufacturer, Canadian Solar, the answer is no. The company sent me module-handling instructions that include "Do not stand, step, walk and/or jump on the module."

I am just curious if this is true with all panel manufacturers. This is a first occurrence for me. Not that our crew walks over the panels all the time, but we haven't had any breakage from other manufacturers.

Also, I have seen promotional videos, even at the SPI conference, that show installation crews walking all over the modules. Any insight is highly appreciated.

SolarPro (David Brearley): I cringe every time I see one of those photos. Installers should not stand on PV modules. Here's the problem: Even if you don't break the glass, the stress is likely to cause microcracks in the PV cells. Microcracks increase series resistance within the module, create hot spots and otherwise accelerate module degradation. Even something as innocuous as leaning on a PV module while torquing a mounting clamp can result in cell microcracks.

Marvin Hamon, PE: Module warranties typically cover manufacturer's defects and loss of power only. In addition, there can be a long list of exclusions: for example, the warranty will be invalidated if you mount the modules at less than 10° tilt, if the PV array is less than 10 miles from the ocean or if you don't follow the installation instructions.

So you are probably not covered by the warranty. However, a manufacturer will sometimes replace a module out of warranty just because it's good

istock.com

Seriously? Some of the stock photos used in solar marketing campaigns show unsafe working conditions or unacceptable material handling, such as standing on modules. Excessive pressure on a module's surface can cause microcracks that accelerate module degradation.

business, good PR or you are a high-volume customer.

Terence: Gentlemen, thank you for the input. @Marvin Hamon: Some manufacturers have told me about the minimum tilt angle. I've always wondered, is this because of the snow load, or is there more to it?

@SolarPro: Very good point about microcracks. Assuming the performance dropped below the guaranteed production values, and it was established that it was due to microcracks, is there a way to differentiate between microcracks caused by localized pressure and those that come from the factory's poor manufacturing processes or quality issues?

Marvin Hamon: Most framed modules have a lip around them that holds water at low angles. While I have not heard a specific reason for the low-angle restriction, I would think it has to do with not allowing water to pool on the module surface and possibly find a way inside. Water infiltration is a significant driver for several types of module failure.

If you send a module back for a power reduction replacement, and it is in good physical condition on the outside, you should get a replacement without too much trouble. If you send a module back with a forklift tine through it and try to claim a power reduction warranty replacement, I don't think you will get too far.

SolarPro: Power warranty claims are notoriously difficult to pursue. You need high-quality testing equipment to identify the problem. The accuracy of the test results needs to be beyond reproach. You might need to hire a third-party O&M service to meet this criterion. Once you have proof that there's a problem, you still need to negotiate the manufacturer's claims process. It may require that you ship all of the questionable modules back at your own expense. Or the manufacturer might send you a quantity of new modules to make up for the lost power, regardless of whether you can integrate those modules into the existing electrical design.

Generally speaking, I think that loss of power due to microcracks would be difficult to trace back to a root cause. Is it a manufacturing defect? Or is it a handling or installation problem? If it were an isolated, low-value claim, a module manufacturer would likely provide a remedy according to its warranty terms.

However, if a system owner was trying to make a power warranty claim on a multimegawatt system and suspected microcracks as the failure mechanism, the monetary value of the claim might justify some very expensive forensics, such as aerial infrared imagery. These images can differentiate manufacturing defects from damage due to mounting. For example, Creotecc has some aerial infrared images that reveal a pattern of temperature variation across ground-mounted PV arrays that appear to result from module mounting or installation methods. These images are likely the type of data a module manufacturer could use to deny a warranty claim based on power loss due to microcracks. In other words, a certain pattern of failure could point away from the product manufacturing process and toward the system design or installation.

Marvin Hamon: It's always good to keep in mind what a warranty really is: an insurance policy. We pay a premium for module insurance in the price of the module, and we hope we don't need to use it. A warranty claim is a pain for everyone.

If a manufacturer is too difficult to deal with and gets a reputation for being strict about warranty claims, it risks losing business to a competitive company that is easier to work with. If it is too lenient in warranty claims, it risks being played by people wanting warranty replacements for modules they damaged.

To make it even more interesting, module warranties are too long to be useful. Even if you have a warranty claim 5 years from system install, the chances of getting warranty replacement modules that work in the old system are close to zero. Things are just changing too fast, and our industry lacks standards that would allow an easy interchange of modules. For a warranty claim before install or up to maybe 2 years after, you might be able to put together a workable fix. After that, it's not so easy. For instance, try to find a drop-in replacement for an AstroPower 4 module panel. It's been about 10 years since that company went bankrupt. That's why in larger installations, owners put modules in storage for future replacements.

Training

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Tucson
Feb 17 – Feb 21
solarenergy.org

CALIFORNIA

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CleanEdison
San Francisco
Feb 17 – Feb 21
cleanedison.com

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CleanEdison
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Mar 17 – Mar 21
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San Diego
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Denver
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Cocoa
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PV Sales & Finance
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education.biz

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NEW MEXICO

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CNM Workforce Training Center
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cnm.edu/wtc

Solar Heating Academy
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ONTILITY
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Solar Training School
solartrainingschool.com

Step Up Education
stepupeducation.com

Sun Pirate
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PROJECTS System Profiles

Frey Electric

Harvest Hill Golf Course

Courtesy Frey Electric (4)

Overview

DESIGNER: Deborah Zarbo, engineer, Frey Electric, frey-electric.com

LEAD INSTALLER: Ray Szopinski, electric site foreman, Frey Electric

DATE COMMISSIONED: July 2013

INSTALLATION TIME FRAME: 18 days

LOCATION: Orchard Park, NY, 43°N

SOLAR RESOURCE: 4.2 kWh/m²/day

ASHRAE DESIGN TEMPERATURES: 86°F 2% average high, –4°F extreme minimum

ARRAY CAPACITY: 37.44 kWdc

ANNUAL AC PRODUCTION: 36,262 kWh

The Harvest Hill Golf Course underwent extensive renovations that were completed in May 2013, including the construction of a new clubhouse, two cart houses and a tournament pavilion. To help reduce facility operations costs, Frey Electric installed a 37.44 kW PV array on the two new cart houses. The array is expected to offset 20% of Harvest Hill's annual energy consumption. While the PV system was not part of the project's initial design, the arrays were relatively easy to integrate with the cart house buildings.

The 144-module array is split across two 12:12 metal standing-seam roofs with azimuths of 240° and 259°. The installers flush-mounted the array with S-5! Mini Clamps and PV Kits, so roof penetrations were not necessary. The steep roof angle presented both challenges and a performance advantage. The crew needed to use a two-person basket lift during the array installation. They pre-assembled S-5! Kits in the shop to reduce field labor and minimize the potential loss of hardware off the roof during installation. At the jobsite, the installers quickly positioned the assemblies, installed and torqued them per specification. The steep roofs offer a performance benefit as the arrays shed snow easily during the winter months, which increases overall energy production.

Each roof has sufficient area for the installation of 72 modules. The corresponding array layouts are well matched for integration with four 10 kW Fronius IG Plus Advanced inverters. The designers initially considered microinverters; however, due to the steep roof pitch and difficult access, they chose string inverters to eliminate the need to access the roof in the event of an inverter failure.

The crew installed Wiley ACE 3-pole transition boxes on each roof to make the transition from PV Wire to THHN conductors. They connected three individual PV source circuits to each Fronius IG Plus Advanced inverter via its integrated fused combiner. Inside each cart house, the ac output of two

inverters is combined in a load center and then connected to a dedicated PV generation meter. The combined output from one cart house runs underground to the other cart house. A third load center combines the output of all four inverters. A fusible disconnect protects this single circuit, which terminates on the load side of a 150 kVA 480/208 service distribution transformer. This was the most economical point of connection, since the existing 208 V panels are located in other buildings.

The crew installed a Fronius Datalogger Web unit and tested it using a WLAN Wi-Fi stick antenna. However, the metal building surrounding the WLAN stick prevented the inverters from receiving an adequate signal. The installers then swapped out the antenna with a Fronius External Antenna LAN stick mounted on the outside of the building and connected to the Datalogger Web using a USB extension cable approximately 80 feet long. Excessive power loss over the USB cable prevented this second configuration from working. Ultimately, the crew moved the Datalogger Web closer to the external antenna and ran a Cat 5 cable to the first inverter.

"Initially, working from lifts added a level of difficulty for the installation crew, but the final product came out well. While the array orientations are not ideal, energy production has been above the projected values."
—Deborah Zarbo, Frey Electric

Equipment Specifications

MODULES: 144 Helios Solar Works 6T 260, 260 W STC, +3/-0%, 8.46 Imp, 30.84 Vmp, 8.9 Isc, 37.73 Voc

INVERTERS: 3-phase 120/208 Vac service, four Fronius IG Plus Advanced 10.0-3 UNI Delta, 10 kW, 600 Vdc maximum input, 230–500 Vdc MPPT range

ARRAY: 12 modules per source circuit (3,120 W, 8.46 Imp, 370.1 Vmp, 8.9 Isc, 452.8 Voc), three source circuits per inverter (9,360 W, 25.4 Imp, 370.1 Vmp, 26.7 Isc, 452.8 Voc), 37.44 kW array total

ARRAY INSTALLATION: Roof mount, standing-seam metal roofing, S-5! Mini Clamps with S-5! PV Kits; 72 modules with 240° azimuth, 72 modules with 259° azimuth, 45° tilt

ARRAY SOURCE-CIRCUIT COMBINERS: Inverter integrated, 15 A fuses

SYSTEM MONITORING: Fronius Datalogger Web with external LAN antenna

Sentinel Solar
Vine Fresh Produce

Courtesy Sentinel Solar (4)

Overview

DESIGNER: Adam Webb, president, Sentinel Solar, sentinelsolar.com

PROJECT EPC: Sentinel Solar

DATE COMMISSIONED: May 2013

INSTALLATION TIME FRAME: 6 months

LOCATION: Strathroy, Ontario, Canada, 42.95°N

SOLAR RESOURCE: 4.3 kWh/m²/day

DESIGN TEMPERATURES: 79°F average high, –1°F record low

ARRAY CAPACITY: 2.3 MWdc

ANNUAL AC PRODUCTION: 2,540 MWh

Before the launch of Ontario's feed-in tariff (FIT) program, the owner of Vine Fresh Produce, a southern Ontario greenhouse operator, explored installing a net-metered PV system at its facility. When the FIT went into effect, the program offered favorable financial returns compared to a net-metered system. The company received a 2 MWac FIT contract and selected Sentinel Solar as the project's EPC. The 2.3 MWdc 3-phase system utilizes 9,294 Enphase microinverters. It is the largest rooftop installation under the Ontario FIT program and the largest Enphase microinverter installation to date.

The design of the greenhouses' sawtooth rooflines shades the bottom portion of each roof section during certain times of the day and the year. Due to this site limitation, a microinverter system

modules with Enphase M215 microinverters. AC branch circuits consisting of 24 inverters (typical) are installed in a center-feed configuration to minimize voltage rise in the Enphase Engage cabling system. The array is composed of twenty 100 kWac subsystems. Each subsystem has 20 branch circuits (typical) that terminate in 400 A panelboards. The ac system is then aggregated in two 1,200 A distribution panels before interconnecting with the site's 600 Vac 3-phase service.

was the optimal approach to mitigate the shading impact on system production. In addition, the facility owner was interested in a distributed system architecture that would prevent significant energy production losses due to equipment failures.

Sentinel Solar worked with Vine Fresh Produce to design an array racking and mounting system that is integrated with the roof structure of the greenhouses. The design replaces glazing panels with modules to minimize materials and reduce additional load on the structures. The unique PV-mounting approach provides full access to each module and microinverter from inside the greenhouses for safe and streamlined O&M activities.

The system's racking, modules and microinverters are all manufactured in Ontario. The system pairs Jinko 250 W

The Vine Fresh Produce O&M staff will provide ongoing monitoring and maintenance of the solar asset. The installation's low dc system voltage and module-level monitoring are both very attractive to the facility's owner, as is the ability to monitor the system remotely and to accurately pinpoint any performance issues.

"For such a large, complex rooftop installation, we knew that being able to track the system's performance at the module level would be beneficial. This was a key consideration in choosing the Enphase system for the Vine Fresh Produce project."

—Andy Bennis, VP of sales and marketing, Sentinel Solar

Equipment Specifications

MODULES: 9,294 Jinko Solar 250W Poly, 250 W STC, +3/-0%, 8.2 Imp, 30.5 Vmp, 8.8 Isc, 37.6 Voc

INVERTERS: 3-phase 600 Vac service, 9,294 Enphase M215-60-2LL-S22-NA, 215 W, 45 Vdc maximum input, 22–36 Vdc MPPT range, 208 Vac output

ARRAY: 24 microinverters per ac branch circuit (typical), center-feed branch circuit configuration, 20 branch circuits per 100 kWac subarray (typical), one 400 A panelboard for each 100 kWac subarray, two 1,200 A distribution panels

ARRAY INSTALLATION: Greenhouse roof mount, custom racking, 180° azimuth, 25° tilt

SYSTEM MONITORING: 20 Enphase Envoy communication gateways, Enphase Enlighten web-based monitoring

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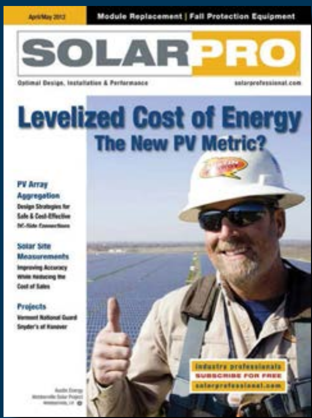

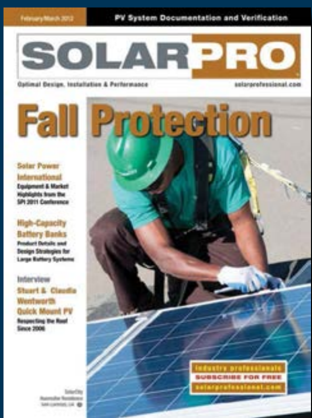

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SunnyMac Solar

Chalmers Residence

Overview

DESIGN FIRM: Sungevity, sungevity.com

LEAD INSTALLER: Matthew Macfadden, SunnyMac Solar, sunnymacsolar.com

DATE COMMISSIONED: October 2013

INSTALLATION TIME FRAME: 5 days

LOCATION: Fenwick Island, DE, 38.5°N

SOLAR RESOURCE: 4.5 kWh/m^2/day

ASHRAE DESIGN TEMPERATURES: 91°F 2% average high, 7°F extreme minimum

ARRAY CAPACITY: 7.35 kWdc

ANNUAL AC PRODUCTION: 8,800 kWh

Equipment Specifications

MODULES: 30 ET Solar ET-P660245BB, 245 W STC, +3/-0%, 8.13 Imp, 30.14 Vmp, 8.73 Isc, 37.27 Voc

INVERTERS: Single phase 120/240 Vac service, one Power-One Aurora Uno PVI-3.0-OUTD-S-US (3 kW, 600 Vdc maximum input, 160–530 Vdc MPPT range), one Power-One Aurora Uno PVI-3.6-OUTD-S-US (3.6 kW 600 Vdc maximum input, 120–530 Vdc MPPT range)

ARRAY: PVI-3.0-OUTD-S-US: seven modules per source circuit (1,715 W, 8.13 Imp, 211 Vmp, 8.73 Isc, 260.9 Voc), two source circuits total (3,430 W, 16.3 Imp, 211 Vmp, 17.5 Isc, 260.9 Voc); PVI-3.6-OUTD-S-US: eight modules per source circuit (1,960 W, 8.13 Imp, 241.1 Vmp, 8.73 Isc, 298.2 Voc), two source circuits total (3,920 W, 16.3 Imp, 241.1 Vmp, 17.5 Isc, 298.2 Voc); 7.35 kW array total

ARRAY INSTALLATION: Roof mount, composition shingle roofing, IronRidge XLR racking; eight modules with 226° azimuth, 23 modules with 136° azimuth, 27° tilt

SYSTEM MONITORING: Locus Energy LGate 101, inverter-level monitoring

Courtesy SunnyMac Solar (2)

The Chalmers Residence is located on the bay side of Delaware's Fenwick Island, an area known for its ocean views and high-end homes. The PV project's biggest initial challenge was balancing aesthetics and performance. Sungevity designed the system and financed it through its residential leasing program. SunnyMac Solar was responsible for system installation.

The arrays are installed on three roof surfaces with two orientations. The designers selected Power-One Aurora Uno inverters, which feature two independent MPPT channels, to maximize system performance.

Because the home has vaulted ceilings, the installers ran all conduit on the exterior of the home and hid it as much as they could. To minimize the visual impact of the raceway system, they installed a SolaDeck junction box on each roof surface. Strategically placed rooftop conduits feed the output circuits of the four separate strings into a single 1-inch EMT conduit. This conduit is tucked out of sight as much as possible and terminates at the system's inverters.

The home is elevated on wooden piles. A strut system under the home supports the inverters, ac load center and associated monitoring equipment. Because the service panel is in an inaccessible interior location, the designers called for a line-side utility interconnection. They rerouted service conductors to allow for a *Code*-compliant connection to the combined inverter-output circuit.

They installed the Locus Energy LGate 101 monitoring system box adjacent to the inverters and connected it to each inverter via Cat 5 cables. The monitoring system uses power line communication to transmit inverter data to an Ethernet bridge connected to the client's wireless router. The LGate 101 provides revenue-grade production metering, load metering and inverter-level monitoring.

> "The challenges presented by the home's multiple roof surfaces and orientations, as well as the requirement to minimize the visual impact of the exterior-mounted raceways, required a high attention to detail. We consider the Chalmers residence system to be SunnyMac's signature residential installation."
> *— Matthew Macfadden, SunnyMac Solar*