April/May 2012

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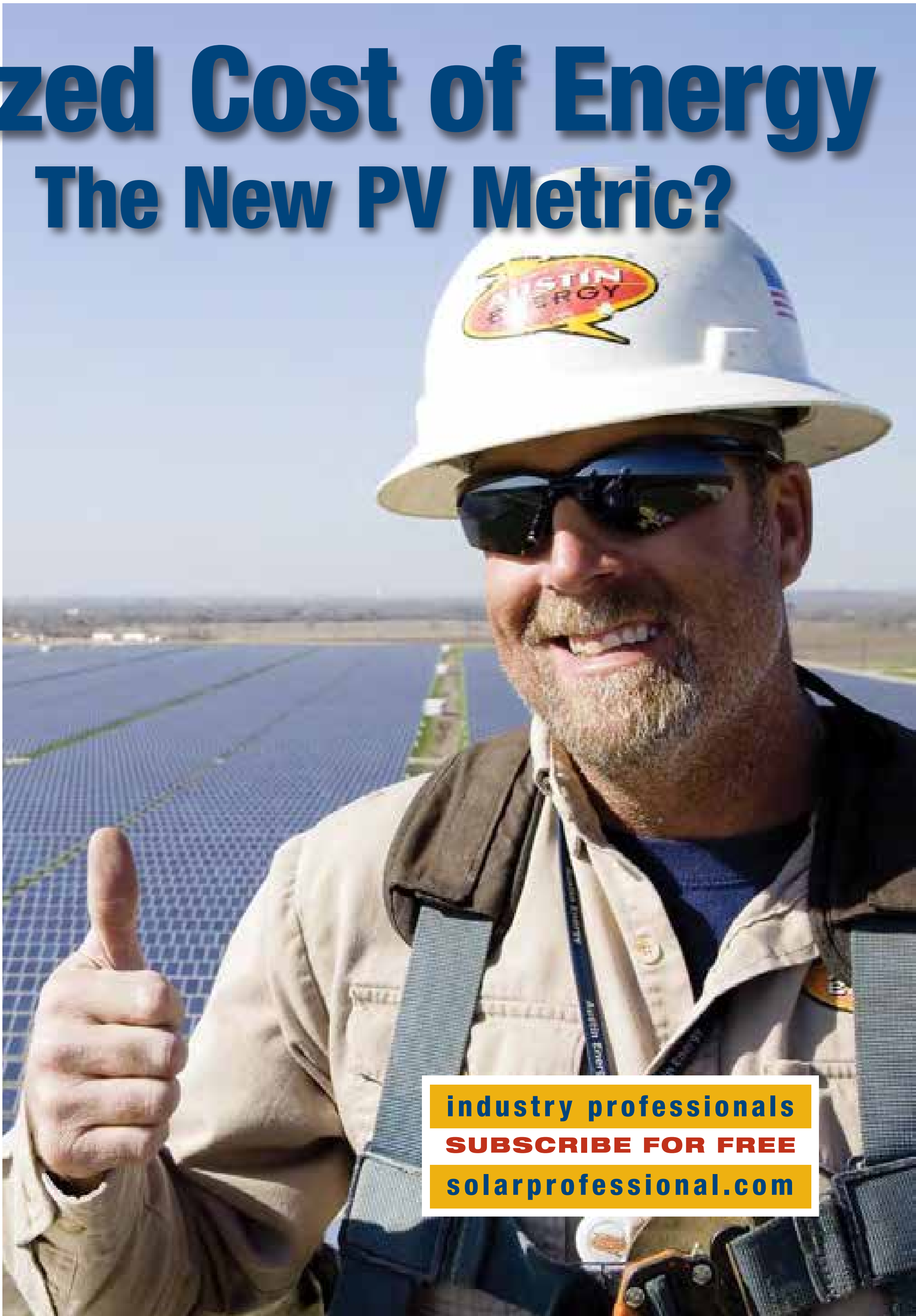

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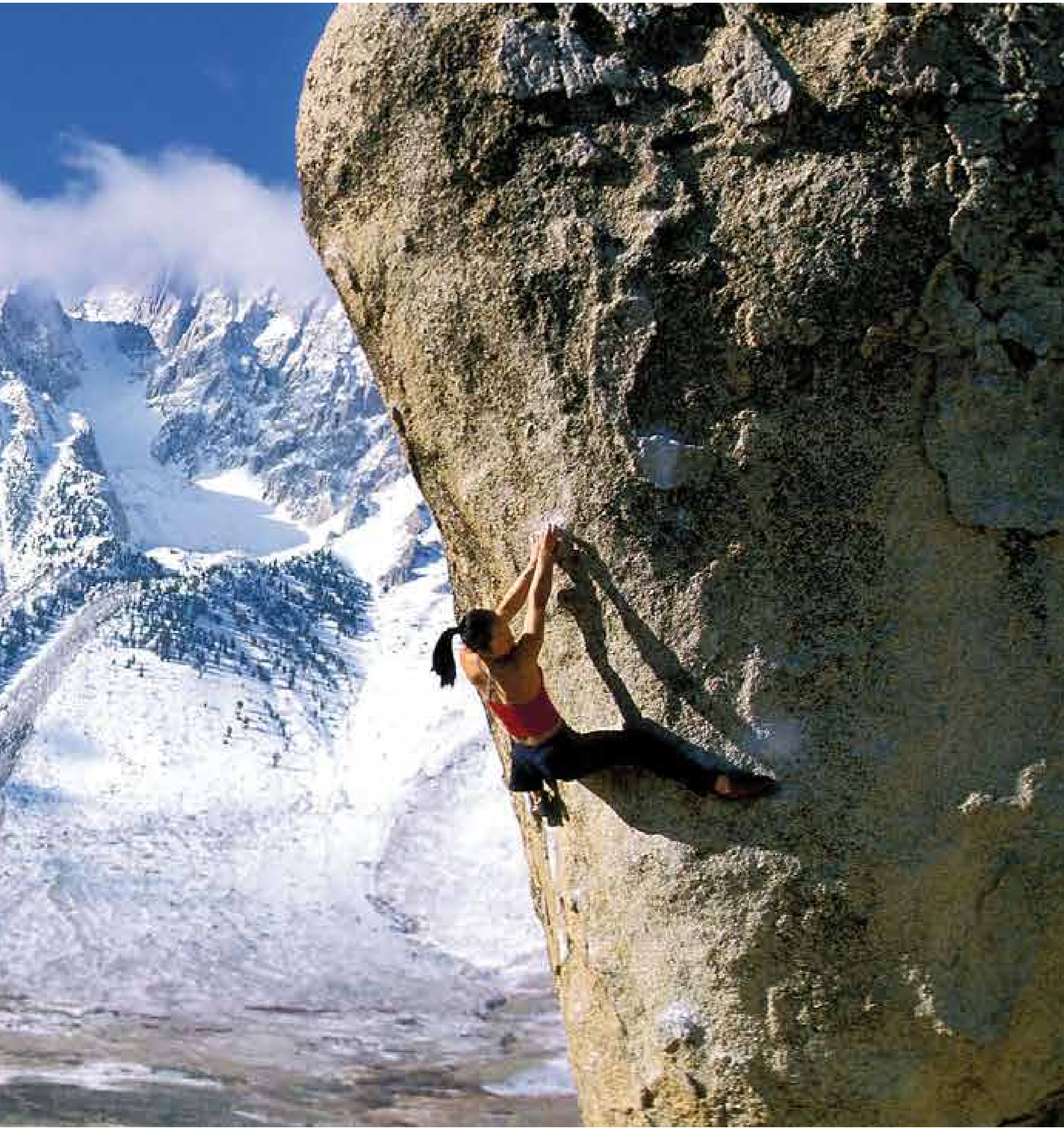

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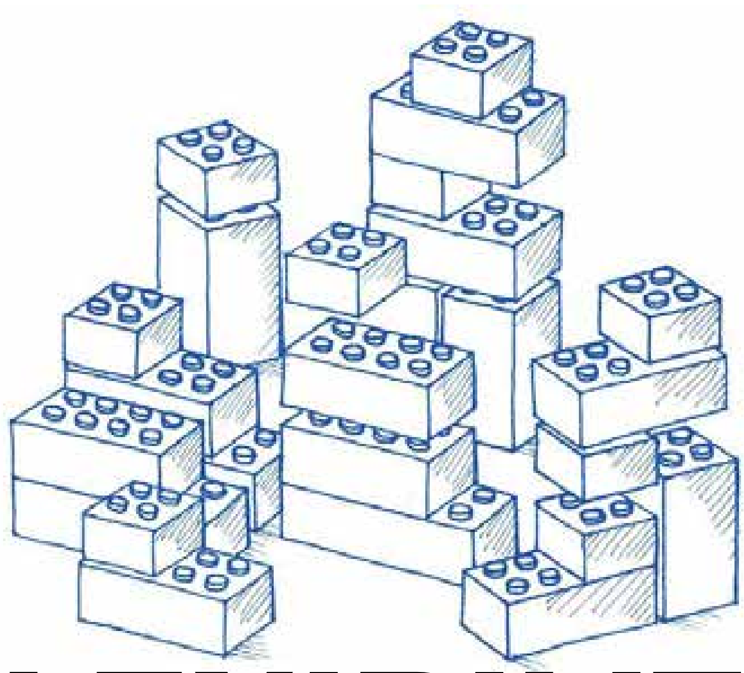
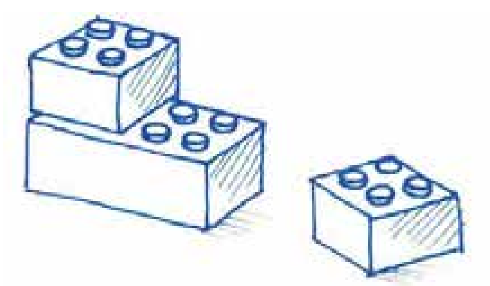
ON THE COVER An Austin Energy powerline technician signals approvingly from his bucket truck overlooking the utility's 30 MWac solar power plant located 20 miles east of Austin, TX. Constructed by RES Americas, the project utilizes Trina Solar modules, Emerson Solar inverters and single-axis trackers from Array Technologies. Photo by Patrick Byrd

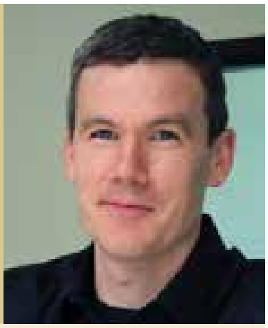




Contributors

Experience + Expertise

Tobin Booth founded Blue Oak Energy because he recognized the critical need for forward-thinking project design and efficient construction execution in the PV industry. With more than a decade of experience with PV systems, he has contributed to more than 350 MW of projects in operation today. Booth holds a BS in mechanical engineering from Colorado State University and is a licensed engineer in more than 15 states.

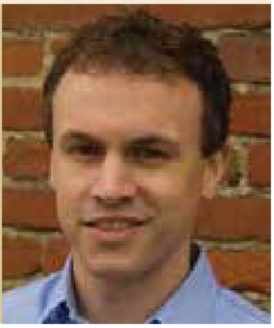


Bradley Hibberd left the oil and gas industry in June 2003 to join Borrego Solar as director of engineering, a role in which he has managed the design and engineering of over 12 MW of PV installations. Hibberd is responsible for the development of the design standards used by Borrego's engineering team and the consolidation of its design and engineering tools. He holds an MS in engineering from the University of Auckland, New Zealand, and is a NABCEP Certified Solar PV Installer.

Peter Hoberg is VP of marketing at Solmetric Corporation and has over 20 years of experience in marketing and business development with Hewlett-Packard and Agilent Technologies. He holds BS and MS degrees in electrical engineering from Stanford University.

Stephen Kane heads the service department for Namasté Solar, an EPC contractor and consulting firm in Colorado. He is NABCEP and COSEIA certified in solar PV installation. Kane has been working in the PV industry for 8 years and has held a variety of positions in areas including sales, design, installation, data monitoring and O&M.

Tarn Yates is an applications engineer for Borrego Solar. He was introduced to solar more than 15 years ago at a wilderness camp in the southern Sierras where he was responsible for maintaining an off-grid PV system. He is a NABCEP Certified Solar PV Installer and a California-certified electrician. Yates holds a BS in physics from the University of California at Santa Cruz, where he completed research into the temperature effects on solar cells in concentrating systems.



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Long-Term Module Replacement and Serviceability

When you have been in business installing PV systems for a few years, you begin to see the challenges in keeping systems running in a cost-effective manner for the long term. One major O&M issue is how to handle broken or malfunctioning modules. System owners purchase your products expecting reliable energy production for 25 years or more, and the industry must think in terms of these long life cycles.

Sometimes the glass on a PV module shatters. This may be due to hail, vandalism, thermal expansion or reasons unknown. Regardless of the root cause, module manufacturers do not typically warrant post-installation module breakage. So the cost of replacing the broken module is borne by the system owner; and the installation is facilitated by the O&M provider, which is often but not always the system installer.

Post-installation module replacement can present any number of challenges, most notably the availability of parts. Module manufacturers are generally engaged in a process of continuous, incremental product improvement. The model you are purchasing today will not be available indefinitely. While it would be ideal for system installers and O&M providers if manufacturers maintained a back stock of older products, manufacturers and distributors are often motivated to reduce and eliminate stranded inventory.

Whenever an identical replacement part is unavailable, the following recommendations can be helpful.

Same product line, different batch. Absent a direct replacement, the next best thing is to track down a module from the same product line, ideally one with a higher power rating. Most manufacturers batch cells and modules so that multiple power ratings are available within the same product line. Regardless of any differences in rated power, the mechanical characteristics within the product line should be identical.

Courtesy Namasté Solar

Service nightmare This residential array uses modules with a proprietary frame profile and mounting system. A broken module was discovered in 2011, 3 years after the installation. The manufacturer was unable to provide a replacement module because it had discontinued the product line.

If a higher-rated module from the same product line is installed as a replacement, the existing source circuit and array should continue to operate as originally intended. As Jim Dunlop explains in chapter 5 of *Photovoltaic Systems* (American Technical Publishers, 2007), "The current output for a circuit of dissimilar devices in series is limited to the current of the lowest-current output device in the entire string." As long as the rated current of the replacement module meets or exceeds that of the existing devices, system operation should be unimpeded. The key is to not introduce a bottleneck in the circuit.

Note that the operating characteristics within a specific product line can change slightly from year to year, as can frame profiles and dimensions. In addition, keep in mind that products operating on a roof for several years exhibit predictable degradation. If you have to replace a 180 W monocrystalline PV module that has been in the field for 3 years with a new 175 W module from the same product line, that is likely acceptable and should present a minimal impact on performance.

Similar electrical characteristics and dimensions. In some cases, necessity may dictate that you use a replacement module from a different product line or manufacturer. If so, be aware that this is not as straightforward as simply replacing a 175 W module with any other 175 W module. It is important to identify a module with similar current characteristics. Ideally, the voltage characteristics and temperature coefficients should also be a reasonably close match.

It is also important to find a module with similar mechanical dimensions so that the replacement fits within the old module's footprint. Aesthetic issues, like matching the frame color, may or may not be an issue, depending on the application.

Reduce string sizes. If you cannot replace the broken module, it may be possible to remove one module from each of the remaining source circuits. This would require a careful analysis of the resulting low array voltage to ensure that the operating voltage remains within the inverter MPPT window during the summer months.

The obvious downside to this approach is that it reduces the array capacity, which tends to limit this option to one- or two-string residential installations. Array aesthetics may also be compromised if unsightly gaps are visible from the ground. However, this solution does not require replacement parts.

Module-level power electronics. So far I have assumed that you are working with conventional string or central inverter installations, as these currently make up the vast majority of installed PV systems. Theoretically, you could deploy a microinverter on a replacement module. While this would eliminate the need to use a replacement module with similar electrical specifications, the mechanical considerations would still remain.

In practice, there are challenges associated with this solution. To start, the BOS and intertie equipment may need reworking. For example, a "PV AC Subpanel" may be required to combine the ac output of the string inverter system with the ac output of the new microinverter system prior to the interconnection point. Further, a new circuit—and probably new conduit—is needed between the replacement module and the interconnection point. Data monitoring components that were not utilized in the original installation may be required, as well as an Internet connection. It is also necessary to maintain the electrical balance in the dc source circuits: If more than one source circuit is present, then more than one microinverter needs to be installed, unless the existing inverter accommodates multiple MPPT inputs. Alternatively, a conventional single-MPPT–input string inverter could be replaced with one that offers dual MPPT inputs, which would allow the system to operate with one less module and unbalanced strings. Work of this scale may require pulling a permit. Once all of the costs are accounted for, other solutions will likely prove more cost effective.

Keep extra modules on hand. In a perfect world, integrators could just keep back stock of all the module SKUs they have ever installed on their customers' homes and businesses. Unfortunately, maintaining an inventory of replacement products poses financial and logistical challenges. Over the years, companies tend to deploy a variety of different products, often from multiple manufacturers. It quickly becomes difficult to find room in the warehouse for extra inventory, not to mention the challenge of carrying it on the balance sheet. After all, integrators have tight margins and operating budgets.

Complicating Factors

From my perspective as the service department director for a successful regional PV system integrator, I find long-term module replacement a potentially messy problem and one without a lot of elegant solutions. PV designers and installers need to keep a long-term perspective when making product choices. Customers expect low- or no-cost maintenance for the life of these systems. This means that you have to think about the replaceability and serviceability of your products.

The more ubiquitous the PV module, the easier it is to find a replacement part. While products that do not require traditional rails and clamps—like modules with integrated mounting features—can speed up installation time and reduce installation costs, they can also be difficult to replace. The more unique the product, the more limited your options are when a replacement part is needed.

For example, consider what happens when an equipment manufacturer stops making a product with a special frame profile that works only with a proprietary mounting system. In my 8-year career in this industry, I have seen replacement parts become unavailable for specialty-framed PV modules several times. Manufacturers simply do not keep a back stock of these products—not even to cover the duration of the 5- or 10-year workmanship warranty, let alone to cover longer-term replacement needs.

If you are dealing with an integrated module and racking product, you may not have the replacement options discussed in this article. If a replacement module is not available with the special groove, lip or hole that the original installation relies upon, then your only choice may be to remove the existing array and replace the entire racking system with one that is more universal. This is obviously a costly solution that involves a lot of labor, requires the purchase of a new mounting system—and will possibly trigger a new permit and inspection process.

Perhaps standard trade sizes for PV modules will develop as the industry matures. If not, then we need to hope that a robust secondary market develops for good used PV modules. As systems age, module replacement will invariably become a larger issue.

Special thanks to Amanda Bybee, VP of Namasté Solar, for her assistance with this article.

—Stephen Kane / Namasté Solar / Boulder, CO / namastesolar.com


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Fall Protection Equipment Inspection and Maintenance

When implementing a 100% fall protection safety program for your installation teams, no amount of planning, training and documentation will make up for deficiencies in fall protection equipment due to regular wear, improper storage or misuse. Employers must verify that each employee has been trained in inspecting fall protection equipment and in its proper use. Employers must also communicate the required procedures for equipment handling and storage.

All fall protection equipment should be inspected before each use. In addition, a routine inspection by a Competent Person should be performed at least twice a year. If any defects are identified in equipment, it should be removed from service immediately. The following inspection guidelines can be used as a starting point in the development of a more specific and comprehensive company procedure for fall protection equipment inspection.

—Karl Riedlinger / SolarCity / San Mateo, CA / solarcity.com

Harness Inspection

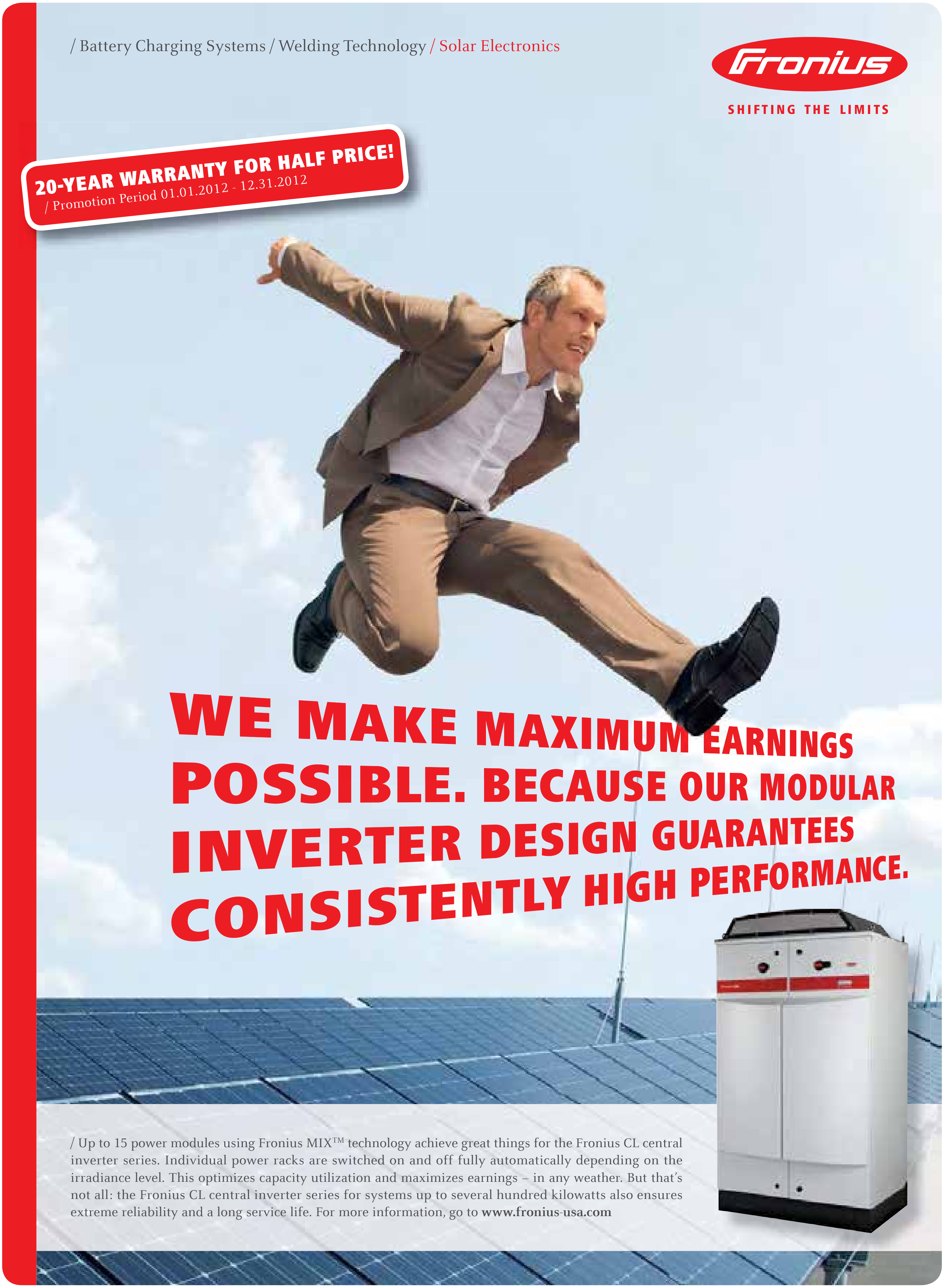
Body harness. For harness inspections, begin at one end of the harness. Hold the body side of the belt toward you, and grasp the belt with your hands 6 to 8 inches apart. Bend the belt in an inverted U. Watch for frayed edges, broken fibers, pulled stitches, cuts and chemical damage. Broken webbing strands generally appear as tufts on the webbing surface. Any broken, cut or burned stitches can be readily seen.

D-rings. Inspect D-rings and D-ring metal wear pads for distortion, cracks, breaks, and rough or sharp edges. The D-ring bar should be at a 90° angle with the long axis of the belt and should pivot freely. D-ring attachments should be given special attention. If rivets are used, they should be tight and flat against the material. Bent rivets may fail under stress.

Tongue buckle. Buckle tongues should be free of distortion in shape and motion. They should overlap the buckle frame and move freely back and forth in their sockets. Rollers should turn freely on the frame. Check for distortion or sharp edges.

Shawn Schreiner (4)

Friction buckle. Inspect the friction buckle for distortion. The outer bars and center bar must be straight. Pay special attention to the center bar's corners and attachment points. CONTINUED ON PAGE 20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Lanyard and Connector Inspection

Lanyard. When inspecting lanyards, begin at one end and work to the opposite end. Slowly rotate the lanyard so that you check the entire circumference. Spliced ends require particular attention. The thimble (the protective plastic sleeve) must be firmly seated in the eye of the splice, and the splice should have no loose or cut strands. The edges of the thimble should be free of sharpness, distortion and cracks.

When inspecting steel lanyards, rotate the wire and watch for cuts, frayed areas and unusual wear patterns. When inspecting a web lanyard, bend the webbing over a piece of pipe and observe each side for any cuts or breaks. For rope lanyards, rotating the lanyard while inspecting it from end to end brings to light any fuzzy, worn, broken or cut fibers. A weakened area caused by extreme loads appears as a noticeable change from the original diameter. The rope diameter should be uniform throughout, following a short break-in period. When steel, web or rope lanyards are used for fall protection, a shock-absorbing system should be included.

Shock-absorbing packs. The outer portion of shock-absorbing packs should be examined for burn holes and tears. Stitching on areas where the pack is sewn to the D-ring, belt or lanyard should be examined for loose strands, rips and deterioration. Shock-absorbing packs are a one-time–use device and should be removed from service and destroyed if they are subjected to a fall event.

Shawn Schreiner (4)

Snap hooks. Inspect snap hooks closely for hook and eye distortion, cracks, corrosion and pitted surfaces. The keeper or latch should seat into the nose without binding and should not be distorted or obstructed. The keeper spring should exert sufficient force to firmly close the keeper. Additionally, carabiners should be inspected. Locking gates on carabiners should work freely and lock as designed. Only locking carabiners are suitable for use in fall protection systems. CONTINUED ON PAGE 22


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Self-retracting lifelines. Fully extend each self-retracting lifeline and inspect the entire length of the lanyard for wear, fraying, nicks and other damage. The lanyard should completely and smoothly retract into the housing. Inspect the housing for cracks and other damage.

Anchor Inspection

Shawn Schreiner (2)

Anchors. Inspect the anchors prior to each use. If an anchor is bent, deformed, cut, gouged or otherwise altered, it should be removed from use and inspected by a Qualified Person or disposed of. Never reuse the fasteners for anchors. Instead, use new hardware with each installation. One-time–use anchors should be inspected for manufacturing defects before use and should be disposed of immediately upon removal so they are not mistakenly reused. If existing anchors are already in place, they should be thoroughly inspected. If there is any doubt about the condition of the anchor or about whether it is attached properly to the structure, new anchors should be installed. ●

Trina Solar Offers New Modules and Design Services

[San Jose, CA] Integrators and project developers in North America can now utilize Trina Solar's Honey line of modules. The product line is available in 60- and 72-cell modules with rated power outputs up to 260 W and 305 W, respectively. The cells used in the Honey modules feature an increased surface area and improved efficiency. Along with the 25-year linear power warranty, Trina offers a 10-year product warranty and a guaranteed positive power tolerance value up to 3%. The modules can be matched with the Trinamount racking system, which offers solutions for all roof types. Trina is also offering complimentary design service for preliminary system layouts, along with performance estimations.

Trina Solar / 800.696.7114 / www.trinasolar.com

GE Announces Commercial PV BOS Components

[Plainville, CT] The EverGold line of BOS products from GE Energy includes 600 Vdc disconnects, combiner boxes and recombiners. The combiner boxes are available in 12- and 24-source–circuit configurations in NEMA 3R enclosures. The recombiners accept up to four 100 A inputs and include a load-break–rated disconnect in a NEMA 4 enclosure that allows for vertical or horizontal installation. The disconnect product line is available in single- or four-pole configurations in NEMA 3R enclosures and features oversized lugs to accommodate large conductors. All of the EverGold BOS components are suitable for use with negatively grounded PV systems. Enclosures are constructed of G90 galvanized steel with white powder coating.

GE Energy / 800.431.7867 / geindustrial.com/solar

SolarEdge Releases New Inverters for North America

[Grass Valley, CA] The newest line of inverters from SolarEdge has been released with CEC-weighted efficiency ratings up to 98%. The inverters are designed to work directly with SolarEdge's dc power optimizers, allowing the fixed-voltage, transformerless inverters to maximize the dc-to-ac conversion. The new line features an increased operating temperature range. The Canadian models have a minimum operating temperature of -40°F. The US models have a -4°F specification. All the inverters have a 140°F maximum operating temperature value. The 3 and 3.8 kW inverters are available for 208 or 240 Vac services, while the larger 5, 6 and 7 kW inverters are compatible with 208, 240 or 277 services. The new inverters also include updated communication boards that eliminate the need for crimped connections.

SolarEdge / 877.360.5292 / solaredge.com

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IREC Develops Interactive Solar Career Map

[Latham, NY] A new website presents career opportunities available in the solar industry for use by instructors, policy makers and job seekers: eere.energy.gov/solar/careermap. The interactive Solar Career Map allows users to visualize the multiple career paths available within the industry and the progression from entry-level positions through advanced-level careers. This visual road map also includes occupational information, skills and competencies, education and training pathways. The Solar Career Map is the product of a national

working group convened by the Interstate Renewable Energy Council (IREC) in its capacity as the national administrator of the US Department of Energy's Solar Instructor Training Network.

IREC / 518.458.6059 / irecusa.org
Solar Instructor Training Network / sitnusa.org

Canadian Solar Releases AC Modules

[San Ramon, CA] The new CommercialAC line of PV modules from Canadian Solar comes complete with a fully integrated microinverter that eliminates both the dc conductors and the bypass diodes. The modules are available in power ratings from 218 to 238 Wac with a CEC-weighted efficiency rating of 95%. The ac module's 208 Vac output interconnects with 3-phase utility services. A three-pole, 10 AWG wiring harness allows up to 39 modules on the same branch circuit, reducing parallel connections within ac load centers. Both the module and the inverter are covered under Canadian Solar's 25-year linear power warranty.

Canadian Solar / 925.866.2700 / www.canadiansolar.com

TEAL Introduces String Monitoring Options

[San Diego, CA] The TEALsolar configurable combiner box line now has wireless communication options available for string-level monitoring via power line communications (PLC), as well as standard Ethernet communications. The combiners come standard with 8- to 36-string inputs and dc disconnects, and are available in multiple enclosure sizes in NEMA 3R, 4 or 4X. The optional TEAL PVobserver monitoring package accommodates string-level monitoring via wireless transmission without the need for additional data conductors for communication. The wireless communications options are through the main dc bus if dc PLC is used, or through an ac power line that originates from a 120 Vac breaker located near the inverter if ac PLC is used. All options utilize SunSpec Alliance–compliant Modbus communications protocols, allowing for data transmission across multiple components.

TEAL / 800.888.8325 / teal.com

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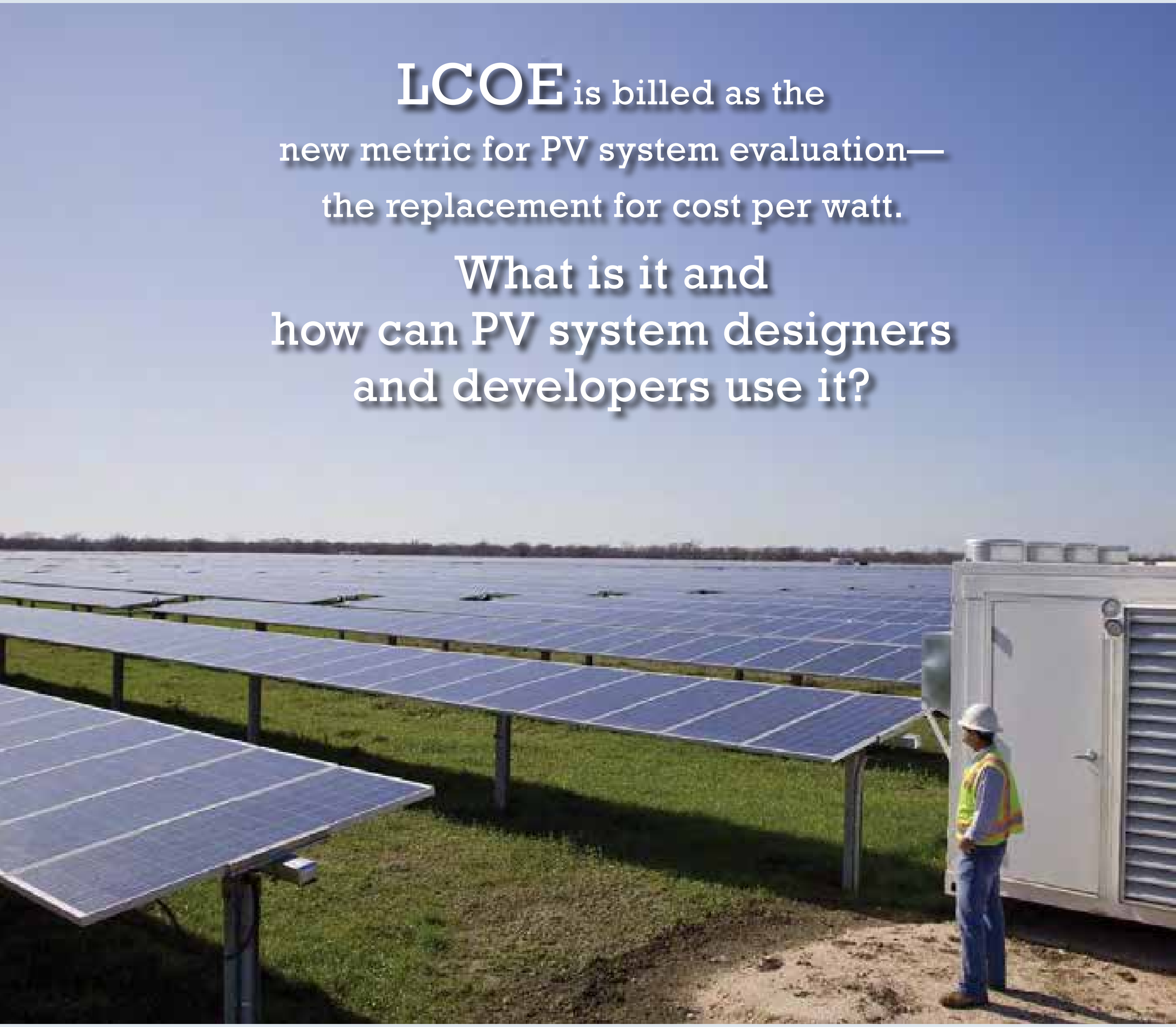


st of Energy

By Tarn Yates and Bradley Hibberd

Courtesy Patrick Byrd

Levelized cost of energy (LCOE) is a widely used term in the PV industry. It is often used as a marketing tool by PV equipment manufacturers or in discussions regarding utility-scale projects. How is it calculated and what are its uses? Is it purely an external metric, something the industry can use to compare its costs to that of other energy sources, or can it be an internal metric employed by developers, engineers and customers in making PV system investment and design decisions?

In this article, we discuss what LCOE is, how it is used and how it is calculated. We then focus on how it can and should be applied in the PV industry. In addition, we analyze some example PV systems and explore appropriate uses for the metric. We also discuss some of the pitfalls associated with LCOE and the limitations of its use.

LCOE Defined

LCOE is used to compare the relative cost of energy produced by different energy-generating sources, regardless of the project's scale or operating time frame. As Thomas Holt and his co-authors define it in *A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies* (see Resources), LCOE is determined by dividing the project's total cost of operation by the energy generated. The total cost of operation should include all costs that the project incurs—including construction and operation—and may incorporate any salvage or residual value at the end of the project's lifetime. Incentives for project construction and energy generation can also be incorporated.

$$\text{LCOE} = \frac{\text{Total Life Cycle Cost}}{\text{Total Lifetime Energy Production}} \qquad (1)$$

As presented in Equation 1, LCOE is a metric that describes the cost of every unit of energy generated by a project in \$/kWh (or ¢/kWh or \$/MWh).

As will be shown directly, this basic definition of the LCOE can be expressed mathematically in more complex ways to account for all of the variables that impact the life cycle cost and total energy production for a PV system.

LCOE Uses

LCOE is most commonly used for evaluating the cost of energy delivered by projects utilizing different generating technologies. Specifically, it is used to rank options and determine the most cost-effective energy source. LCOE may also be used to compare the cost of energy from new sources to the cost of energy from existing sources. In this context, it is useful to policy makers deciding how future energy needs will be met and which technologies to support, and to utilities and project developers selecting technologies. It should be noted that energy-efficiency projects may also be evaluated using the metric.

Because it captures total operating costs, LCOE enables comparisons between significantly different technologies, but it may also be used to compare the cost of energy from variations of the same technology. Options related to components or system design can be evaluated to see what impact they have on LCOE. For example, a developer of a new PV module technology that is more efficient, but also more expensive, could use LCOE to determine performance or cost benchmarks that would need to be met in order for the technology to be competitive and adopted in the market. Similarly, LCOE could be used to identify areas where cost-savings research would be most valuable.

While LCOE is useful for comparing the cost of energy from multiple technologies or evaluating the differences between sources utilizing the same technology, it should not be the only metric that is considered when doing so.

Determining LCOE

Equation 1 may be rearranged mathematically to state that the LCOE—the cost of every unit of energy generated by the project—multiplied by the total units of energy generated by the project is equal to the total cost of operation for the project. The total cost of operation of the project is typically known as the *total life cycle cost* (TLCC). This revised expression is shown in Equation 2:

$$\text{LCOE} \times \text{Total Lifetime Energy Production} = \text{Total Life Cycle Cost} \qquad (2)$$

(Equations 2 through 6 are also drawn from *A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies* by Holt and his colleagues.)

In LCOE calculations, costs are discounted to present day (see Sidebar below) to allow direct comparison between projects with differing cost structures or cash flows. Thus, both the TLCC and the value of the energy generated CONTINUED ON PAGE 32

Key Financial Concepts

While it is beyond the scope of this article to thoroughly explain the financial theory behind the LCOE equation, there are two key concepts that you need to understand.

Cash flow. For the purposes of the LCOE calculation, the *cash flow* is a table showing the amount of money either spent or received each year over the life of the project. The values included in the cash flow vary depending on how the project is financed and whether you are considering tax credits or incentives.

In a simple example, the Year 0 value for a PV project cash flow would include the capital cost of installing the system and any up-front investment or capacity-based incentives. All tax credits, tax savings and performance-based incentives would begin to be recognized in Year 1. For most subsequent years, the only costs in the cash flow would be relatively small O&M expenditures. The likely exception to this would be the year when the inverter needs to be repaired or replaced. In some scenarios, the value of the equipment or material is included in the cash flow at the end of the project lifetime.

If the value of money was static over time, then the total life cycle cost of the project would be determined by simply summing each value in the cash flow. However, a dollar today is worth more than a dollar tomorrow, which leads us to the concept of *present value.*

Present value. In the context of this discussion, we want to determine how much each annual value in our project cash flow is worth in today's dollars. To figure this out, we need to multiply each value by some factor less than 1. This factor is called the *discount factor* and can be represented by the following equation:

$$\text{Discount Factor} = \frac{1}{(1 + d)}$$

where d is the rate of return that could be expected from equivalent investment alternatives. The discount factor can be difficult to define and varies from project to project and over time.

A present value calculation allows you to account for the timing of expenditures or revenue and puts a higher value on costs and income that occur near the beginning of a project. This is important when comparing technologies because they often have different long-term cost profiles. Renewable technologies often require a large up-front investment and incur little cost over the project lifetime, whereas traditional sources of energy often have a lower up-front cost but require continuing significant investment in fuel costs.

are present-value calculations. The terms in Equation 2 may be expressed as follows, where N is the number of years in the analysis period (the project lifetime), C_n is the value of the cash flow in US dollars and Q_n is the energy generated in kWh by the system in year n:

$$\text{Total Life Cycle Cost} = \sum_{n=0}^{N} \frac{C_n}{(1+d)^n} \tag{3}$$

$$\text{LCOE} \times \text{Total Lifetime Energy Production} = \sum_{n=0}^{N} \left(\frac{\text{LCOE}}{(1+d)^n} \times Q_n\right) \tag{4}$$

Substituting the expressions of Equations 3 and 4 into Equation 2 results in the following:

$$\sum_{n=0}^{N} \left(\frac{\text{LCOE}}{(1+d)^n} \times Q_n\right) = \sum_{n=0}^{N} \frac{C_n}{(1+d)^n} \tag{5}$$

The equation may be rearranged to solve for LCOE in \$/kWh, thusly:

$$\text{LCOE} = \frac{\displaystyle\sum_{n=0}^{N} \frac{C_n}{(1+d)^n}}{\displaystyle\sum_{n=0}^{N} \frac{Q_n}{(1+d)^n}} \tag{6}$$

The equation in this form gives the impression that the energy generated is discounted. However, if you examine Equation 5, you can see that it is the value of the energy produced each year that is discounted rather than the energy itself. The appearance that the energy is discounted is simply a function of the algebra. For the purposes of this discussion, LCOE is assumed to have a constant value with respect to time.

The TLCC should include all costs required to operate the system over its lifetime. The most obvious of these are the construction or capital cost and the operation costs, including fuel and maintenance. Additional expenses such as, but not limited to, those related to financing the construction or insuring the system during its lifetime must also be included, as must property taxes if levied. The total energy generated by the system must incorporate variations in energy production, such as losses due to degradation.

In determining the LCOE of a PV system, the following factors should be considered:

Costs
- Initial investment or capital cost
- O&M and operating expenses
- Financing costs
- Insurance costs
- State and federal income taxes
- Property taxes
- Required return on investment
- Decommissioning or removal

Incentives
- Federal tax credit
- Accelerated depreciation (MACRS)
- Incentive revenue

Energy
- Estimated Year 1 production
- Annual degradation
- System availability

Equation 6 can be expanded to show how the factors listed above can be included in the LCOE calculation. In Equation 7 (see below), I is the initial capital cost of the project, D is depreciation, t is the tax rate, O is the annual operating cost (including O&M, loan payments, finance and insurance), R is incentive revenue, S is salvage or residual value, Q_1 is the Year 1 estimate of energy production, and deg is the degradation rate.

Incentives that apply to a project—such as an investment tax credit—should be incorporated with consideration to when they appear in the project cash flow; they may not be realized at the same time as the expenditure they are based on. Finally, all of the terms shown in Equation 7 may not be applicable to every project, and there may be additional project-specific terms that should be included. CONTINUED ON PAGE 34

$$\text{LCOE} = \frac{I - \displaystyle\sum_{n=0}^{N} \frac{D}{(1+d)^n} \times t + \sum_{n=0}^{N} \frac{O}{(1+d)^n} \times (1-t) - \sum_{n=0}^{N} \frac{R}{(1+d)^n} \times (1-t) - \frac{S}{(1+d)^n}}{\displaystyle\sum_{n=0}^{N} \frac{Q_1 \times (1-deg)^n}{(1+d)^n}} \tag{7}$$

LCOE ≠ LCOE

Not all LCOEs are created equally. Making comparisons between LCOE values from different sources must be approached with caution. Various factors may be included in LCOE calculations—incentives, O&M, insurance, taxes and so forth—and a number of assumptions may be made, such as the analysis period and the discount factor. To get a true apples-to-apples comparison between projects or between technologies, the same factors must be included in each calculation. Even a small change in the assumptions that went into the calculation can drastically change the results, making comparisons unrealistic and invalid.

To add further confusion, there are two different types of LCOE that can be calculated: *nominal* and *real*. Which of these is calculated depends on whether the nominal or real discount factor is used in the energy production term of the LCOE equation (the left side of Equation 5). The nominal LCOE is higher than the real LCOE because the nominal LCOE is a current value calculation that is not adjusted for inflation, whereas the real LCOE is a constant-value, inflation-adjusted calculation. The real LCOE is generally preferred for long-term analysis.

The Relative LCOE of PV Systems

If you make some assumptions and do some algebra with the LCOE formula, you can derive a very useful rule of thumb for evaluating changes to a PV project, specifically determining whether a change that has a cost implication is beneficial.

If you assume that variables other than performance, capital and operating costs in the LCOE equation remain proportional to the capital cost or system size, then the following can be shown: *If a change to a project increases the energy production by a greater percentage than it increases the cost, then that change decreases the LCOE.*

A caveat to this conclusion may be the O&M cost. In general, the O&M cost is small relative to the capital cost, or proportionally it differs little between two systems and as such has little influence. As capital costs decline or more expensive O&M is required, then O&M cost becomes more significant, which may affect the applicability of this rule of thumb.

In practice, this rule of thumb means that if a tracking PV system that yields 15% more energy than a fixed-tilt system can be built and operated for 10% greater capital and O&M cost, the LCOE of the tracking solution is lower than that of the fixed-tilt solution. Conversely, if buying higher-efficiency modules that produce a 3% increase in yield requires an increase of 5% in total system cost, then the LCOE of the system with the more-efficient modules is reduced.

Essentially this rule of thumb holds that performance, capital cost and O&M cost are proportional to each other and that the relative LCOE of two systems is independent of all variables other than these.

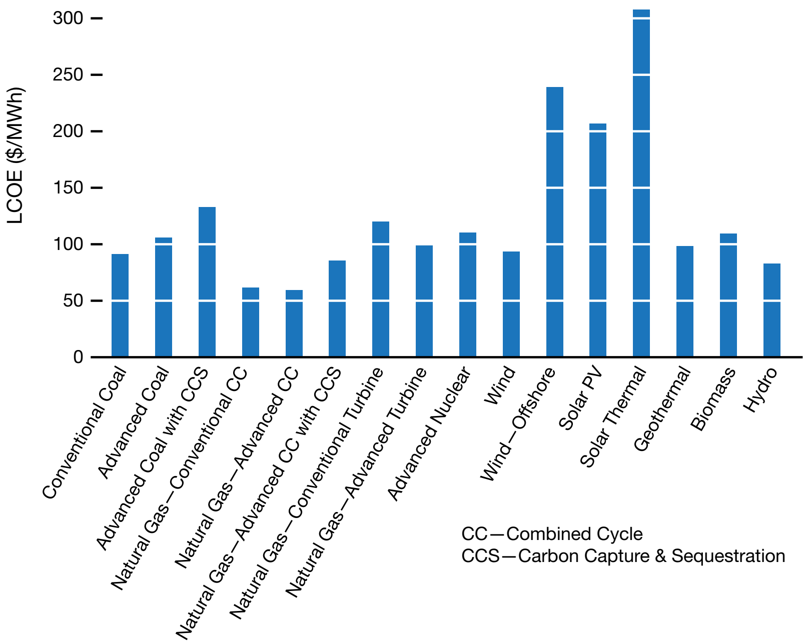
Different Generating Technology LCOEs

One of the most widespread uses of LCOE has been in comparing the cost of energy delivered from different sources, such as conventional fossil fuel, nuclear and renewable materials. These different energy sources have very different cost structures and performance characteristics. For example, coal plants have significant capital and operating costs and a consistent generation profile, as evidenced by a high capacity factor (the ratio of a power plant's actual output over time to its potential output based on its nameplate capacity). In contrast, PV systems are characterized by high capital costs, low operating expenses and a low capacity factor, due to the nature of the solar resource. The LCOE metric takes these differences into account and enables direct comparison.

The US Department of Energy's Energy Information Administration regularly analyzes and publishes the LCOE of a wide range of generation technologies (see Resources). Figure 1 (p. 36) is based on data published in December 2010, which looks forward to plants coming on line in 2016. The purpose of this article is not to discuss the relative merits of the different technologies; rather, it is to explore the usage of LCOE. However, it is notable that the current low-cost electricity source is a natural gas plant, either a conventional or an advanced cycle. The assumptions made in producing this data are not presented here; however, we note that incentives were not considered in the analysis and that the LCOE of carbon-intensive technologies such as coal-fired plants is increased in an attempt to account for potential future costs of carbon emissions.

Grid Parity and the PV Market

Grid parity is a metric regularly used in evaluating the viability of renewable energy sources, which have historically been thought of as too expensive. For a retail customer, grid parity is achieved when the cost of power from an energy project is equal to or less than the retail price of power from the utility. However, it can be difficult to quantify when grid parity is reached. According to Branker, Pathak and Pearce in "A Review of Solar Photovoltaic Levelized Cost of Electricity" (see Resources), "The concept of grid parity for solar PV represents a complex relationship between local prices of electricity, solar PV system price . . . and local attributes." CONTINUED ON PAGE 36



Courtesy Borrego Solar

Figure 1 This chart summarizes the average LCOE by technology for power plants entering service in 2016 in the US, as estimated by the Energy Information Administration.

Utilities do not charge one set rate per kWh. The rate varies depending on market and by location. It can also change depending on when the power is used. In addition, the power output of many renewable energy projects is strongly dependent on the availability of local resources, such as solar insolation and wind. The result is that grid parity occurs at different project costs for different regions and at a higher rate for residential customers, followed by commercial and industrial customers, and lastly for power delivered at the utility scale.

"You cannot effectively compare LCOE to a single point value like today's electricity price," explains Nate Blair, manager of the data analysis and visualization group at the National Renewable Energy Laboratory (NREL). He continues, "The LCOE includes projections about future inflation and fuel cost changes, but that's not what you see in a single point value like electricity price. To make an effective comparison, you need to take the LCOE of future projected electricity prices into account."

The LCOE of an energy project is often compared to grid prices. This is a good first approximation because, when done correctly, an LCOE calculation accounts for regional and market variables. However, simply comparing the LCOE of a technology or project to the grid cost of electricity does a disservice to that technology or project. While LCOE captures all future anticipated costs, the current utility rate for electricity is only a snapshot.

In most cases the rate for utility power is anticipated to increase due to changes such as increased fuel costs or regulatory changes. To compare the LCOE from a new project to the cost of power from a utility, an LCOE calculation should be performed on the anticipated cost of utility power over the same lifetime as for the new project. The resulting value may be compared to the LCOE of the new project.

Here we have considered grid parity from the perspective of a retail consumer of electricity. As Nat Kreamer, CEO of Clean Power Finance, points out (see p. 48), the topic is even more complex when considering grid parity from the perspective of a utility or an independent power producer.

Example LCOE Analyses

While LCOE is not always the appropriate metric to use when evaluating project-specific decisions, it is an excellent tool for evaluating trends or big-picture issues. In the following examples, we explore some familiar questions in the PV industry and show how LCOE can be used to provide insight. These examples include evaluating how LCOE varies in different areas in the US, comparing single-axis tracking and fixed-tilt projects, analyzing inverter loading, analyzing module cost versus degradation rate and looking at downtime as it relates to system cost.

To provide consistency in the examples, we have defined two baselines: a fixed-tilt, ground-mounted PV system, and a single-axis tracking system. The values provided are not intended to represent the actual LCOE for a given configuration or location. Rather, they are included to show the relative values that result from varying the input assumptions. The real, rather than the nominal, LCOE is reported in each case.

LCOE VS. LOCATION

Site selection can have a major impact on a project's feasibility. The weather conditions at a project site and its geographical location have implications for construction costs due to labor rates or building costs associated with land preparation or terrain, interconnection costs (these may be utility mandates, upgrade requirements due to limited utility infrastructure or distance from suitable power lines), or simply the cost of land.

It is clear that a PV system in Phoenix, Arizona, produces more power than a similar PV system in Portland, Oregon, but what does this difference mean with regard to the cost of energy from each system? What does it mean for the level of incentives that might be required to make solar financially viable in the two markets? What will PV need to cost before it makes sense in Massachusetts CONTINUED ON PAGE 38


Nature provides us with the gift of energy through the sun, but unfortunately, nature's wrath may not be all that friendly to your PV system under stressful conditions. Snow, wind, extreme heat or cold, and seismic activities can wreak havoc on underengineered, underdesigned and insufficiently tested racking structures. Only UNIRAC solar structures have been engineered and third-party tested to withstand the harshest of elements and events for a long and enduring service life. Complies with IBC, IRC, ASCE-7-05, ADM, AISI, AISC, NEC and UL. For the highest level of engineering and construction with the lowest cost of ownership in the business, Unirac is the 24/365 solution for performance in and out of the sun. Visit unirac.com for more information.
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Table 1: Baseline System

	Fixed-Tilt Ground Mount	Single-Axis Tracker
Location	Sacramento, CA	Sacramento, CA
Size (dc)	1.2 MW	1.2 MW
Tilt	25°	0°
Azimuth	180° (south)	180° (south)
Inverter capacity	1 MWac	1 MWac
Inverter efficiency	96% CEC	96% CEC
Ground cover ratio	50%	No current function in SAM
System downtime	0.3% per year	0.5% per year
Annual degradation	0.5% per year	0.5% per year
Installed cost	$3.42 per Wdc	$3.68 per Wdc
O&M cost	0.5% of installed cost	0.6% of installed cost
LCOE (real)	0.0901 $/kWh	0.0790 $/kWh

Courtesy Borrego Solar (3)

Table 1 This table describes the baseline systems used for the following LCOE analyses.

Table 2: Financial Assumptions

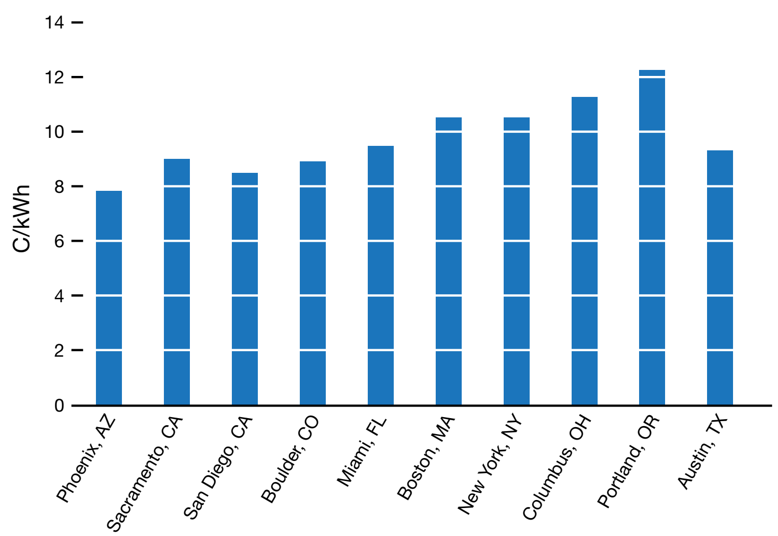
Analysis Period	20 years
Inflation rate	2.50%
Real discount rate	8%
Nominal discount rate	10.70%
Federal tax rate	35%
State tax	7%
Sales tax	8%
Insurance	0.5% of installed cost
Property tax	0%
Debt fraction	40%
Loan rate	7.50%
Loan term	15 years
Depreciation	5-yr MACRS federal and state
Tax credit	30% federal ITC
Incentives	N/A

Table 2 This table defines the financial assumptions used for the following LCOE analyses.

or New York without incentives? An LCOE calculation is essential to answering these questions.

While it is beyond the scope of this article to provide a comparison that would factor in all of the variables that change with location, it is a relatively straightforward task to evaluate how the LCOE of a PV system varies with the solar resources in different parts of the US. Changing the weather data used to simulate the production for the baseline fixed-tilt system from Table 1 enabled us to create the graph shown in Figure 2. (The financial assumptions we used for these analyses are detailed in Table 2.) Among other things, Figure 2 shows that, all else being equal, the LCOE for a fixed-tilt system in Portland is 56% higher than the LCOE for a fixed-tilt system in Phoenix.

Figure 2 The relative LCOE in cents/kWh for 25° fixed-tilt PV systems is shown here for a variety of locations in the US.



SINGLE-AXIS TRACKER VS. FIXED TILT

It is well known that single-axis tracking systems are more appropriate in some locations than in others since the production gain from a single-axis tracker over a fixed-tilt system is larger for sunny locations at southern latitudes compared to the gain at northern latitudes. How much better are single-axis trackers? Are there locations in the US where a fixed-tilt system provides better results than a single-axis tracker?

To provide insight into these questions, we ran LCOE calculations for our baseline fixed and tracking systems defined in Tables 1 and 2. Note that the installation cost, O&M cost and system downtime were increased for the single-axis tracker relative to the fixed-tilt system, and the weather data was varied. The other variables were held constant for the two project types. The results are provided in Figure 3 (p. 40). This exercise did not account for changes in construction costs that may occur in different locations in the US; however, the trends observed are still relevant.

As can be seen in Figure 4 (p. 40), the decrease in the LCOE for a single-axis tracker project in locations such as Phoenix and Sacramento is more than three times greater than CONTINUED ON PAGE 40

the decrease in the LCOE seen in New York and more than two times greater than the decrease seen in Boston. Looking at these results, it is clear why single-axis trackers are a popular choice for projects in locations such as Phoenix or Sacramento. The LCOE for single-axis tracker projects is reduced by more than 12% in these locations compared to a fixed-tilt project.

It is also understandable why a fixed-tilt system might be chosen for a project constructed near Boston or New York. For these locations, the LCOE is only 5.8% and 3.5% less, respectively, with a single-axis tracker than with a fixed-tilt system. This decrease in LCOE could quickly be lost when you consider the additional weather-related issues that might occur in these locations, such as the effect of snow and ice on tracker accuracy and reliability, or the increased O&M costs that might be incurred due to snow damage.

The result for San Diego is both surprising and informative. While a single-axis tracker still provides a 7.2% lower LCOE than a fixed-tilt option, the difference is not nearly as pronounced as might be expected from the results in other locations. Without running this analysis, it would be easy to assume that the results in San Diego would be similar to those seen in Sacramento and Phoenix. However, when you compare the weather data for San Diego to the data for Sacramento or Phoenix, you see a higher percentage of diffuse irradiance in San Diego, which decreases the effectiveness of the tracker. The higher percentage of diffuse irradiance is likely due to San Diego's proximity to the coast, and we would expect these results to change as a project site moved further inland.

Note that the production modeling portion of NREL's System Advisor Model (SAM) tool does not currently model backtracking, which makes the production estimates for the tracker slightly higher than they should be.

INVERTER LOADING

One of the most frequently asked questions in the PV industry is how to load inverters. What should the ratio be between module capacity in dc watts and inverter capacity in ac watts? Typical answers to this question include the following:

- Use a rule of thumb (for example, size for a ratio between 0.8 and 1.2).
- It is worth paying the extra money to slightly oversize the inverter because the inverter will last longer.
- The inverter should be sized so that no power will be lost even under increased irradiance conditions, such as those caused by cloud-edge effect.
- The inverter should be overloaded as much as possible to drive down the installed cost.

Each of these answers is intended to provide the best results for the customer or investor. The goal is to pay as little as possible for the inverter without losing too much power to clipping or to long-term CONTINUED ON PAGE 42

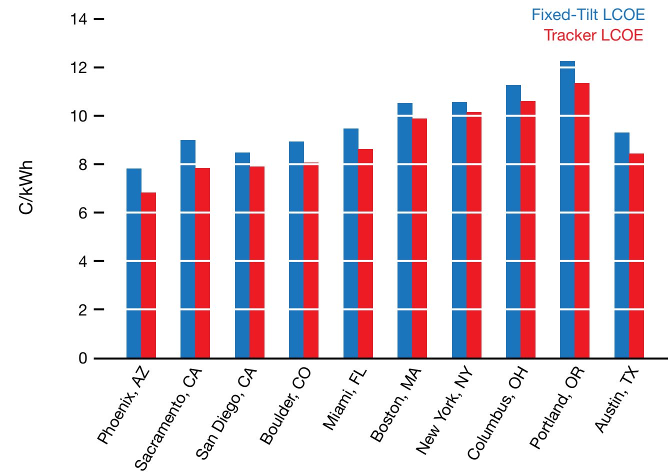
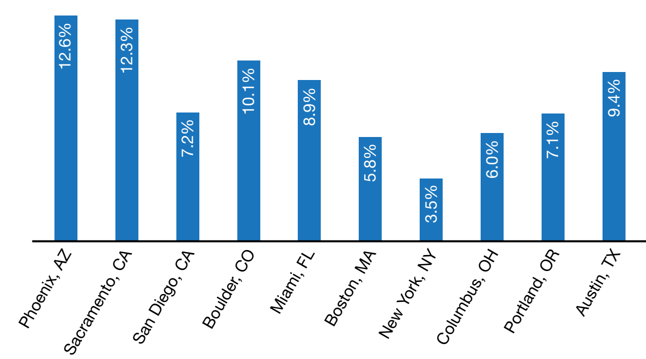


Figure 3 This chart shows the relative LCOE for 25° fixed-tilt versus single-axis tracking PV systems for a variety of locations in the US.



Courtesy Borrego Solar (2)

Figure 4 This chart shows the relative percent difference in LCOE for the tracker PV systems as compared to the fixed-tilt PV systems.

System Advisor Model

Many of the examples that are presented in this article were calculated using System Advisor Model (SAM), a software package developed by the National Renewable Energy Laboratory (NREL). SAM is a powerful tool for comparing the production and financial characteristics of renewable energy projects including concentrating solar power, solar water heating, wind, geothermal and biomass. It contains detailed financial models for evaluating residential, commercial, power purchase agreement (PPA) and utility independent power provider (IPP) projects. Additionally, SAM provides parametric, sensitivity, optimization and Monte Carlo analyses.

inverter downtime. This is precisely where an LCOE calculation can be useful. An LCOE analysis can capture all of the major variables that go into this decision: inverter cost, system production and inverter life or downtime.

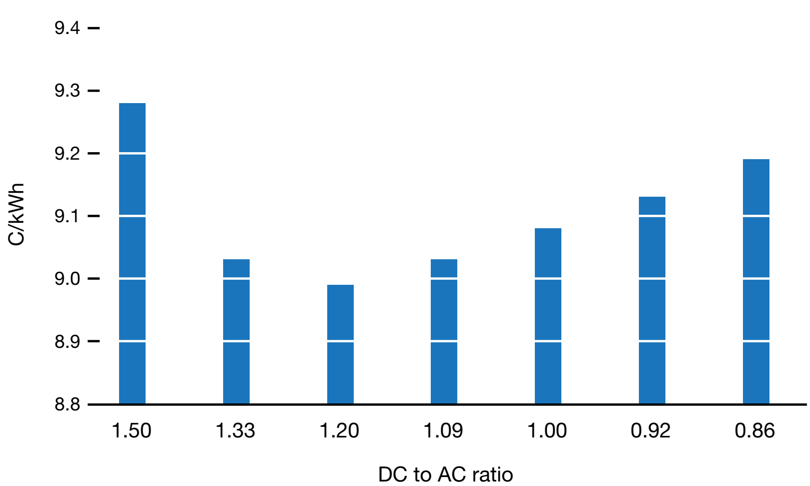
As an example, we ran a parametric analysis on the fixed-tilt baseline system defined in Table 1 (p. 38). In the process, all the variables were held constant except for the size of the inverter, which was varied in 100 kW increments. The cost for the inverter was assumed to be $0.22 per ac watt. As you can see in Figure 5, the array-to-inverter ratio that results in the lowest LCOE for this example is 1.2. It also should be noted that options between ratios of 1.09 and 1.33 produce similar results.

An array-to-inverter ratio of 1.2 is within the guidelines set by most inverter manufacturers for acceptable inverter loading. For this reason, we did not consider additional downtime or decreased inverter life. However, there are cases where a similar LCOE analysis would result in a much higher ideal array-to-inverter ratio. Such cases might include arrays with low tilts (5° or lower) in hot climates, or in situations with high fixed interconnection costs where a utility or an incentive program has capped the ac system size but has not capped the dc size.

Running a similar analysis on a rooftop system with a 5° tilt in Phoenix indicates that an array-to-inverter ratio of 1.33 results in a lower LCOE ($0.0827/kWh) than a ratio of 1.2 or smaller ($0.0829/kWh). However, this ignores the possibility that this elevated inverter-loading ratio may decrease the life of the inverter. Without doing an LCOE calculation, this concern can be difficult to quantify. However, the metric lends itself to this type of analysis.

If the system with an array-to-inverter ratio of 1.33 had as little as 0.1% more downtime a year, then the LCOE of the system loaded at 1.33 would be higher than the system loaded at 1.2. Similarly, if the increased inverter loading resulted in the inverter failing 2 years earlier—assuming as a baseline that the inverter would need to be refurbished in Year 10 at 50% of the initial cost—then the LCOE would be better for the system loaded at 1.2. This type of data allows a system designer to make informed decisions.

Figure 5 This chart shows how LCOE varies according to the array-to-inverter ratio for a 25° fixed-tilt PV system in Sacramento, CA.



Courtesy Borrego Solar

MODULE COST VS. DEGRADATION RATE

Imagine that it is December 2011, and you receive an email from a distributor offering a fire sale on modules at $0.85 per watt. This is a great deal, but what if these modules are of a lower quality than the ones you would usually purchase at $1.20 per watt? At what rate of module degradation would the less expensive modules actually be a bad deal? One of the ways to answer this question is by running an LCOE calculation.

Figure 6 (p. 44) shows the results of a parametric analysis run for the baseline fixed-tilt system (see Table 1) where both the module cost and the degradation rate were varied. The lines on the chart represent a fixed LCOE value and indicate which combinations of degradation rate and module cost result in each value. This chart suggests that for this example, if all other values are held equal, a module can degrade about 0.5% more per year without having a negative impact on the LCOE if the cost is $0.10 less per watt. You could run similar analyses to look at risk factors that might be associated with less-expensive modules, such as the effects of an increased rate of module failure or a lower nameplate power tolerance.

LCOE VS. SYSTEM AVAILABILITY

Manufacturers and system designers always look for ways to drive down the installed cost of PV systems. Many of the methods considered involve some risk of increased system downtime due to component failure or incorrect installation. LCOE allows you to understand the tradeoffs between cost savings and potential increases in system downtime.

In this scenario, we ran a parametric analysis on the baseline fixed-tilt system (see Table 1) where the installation costs and system availability—the percentage of time that a system is fully functional—were varied. Figure 7 (p. 44) shows the somewhat surprising results. In the range shown in this example, a savings of $0.05 per watt in the installation cost can result in about 1.5% more system downtime per year without having a negative impact on LCOE. This analysis does not include the cost of any repairs that might be required to fix the cause of the system downtime. It also does not consider the negative impact that system downtime might have on the installer's or manufacturer's reputation. CONTINUED ON PAGE 44

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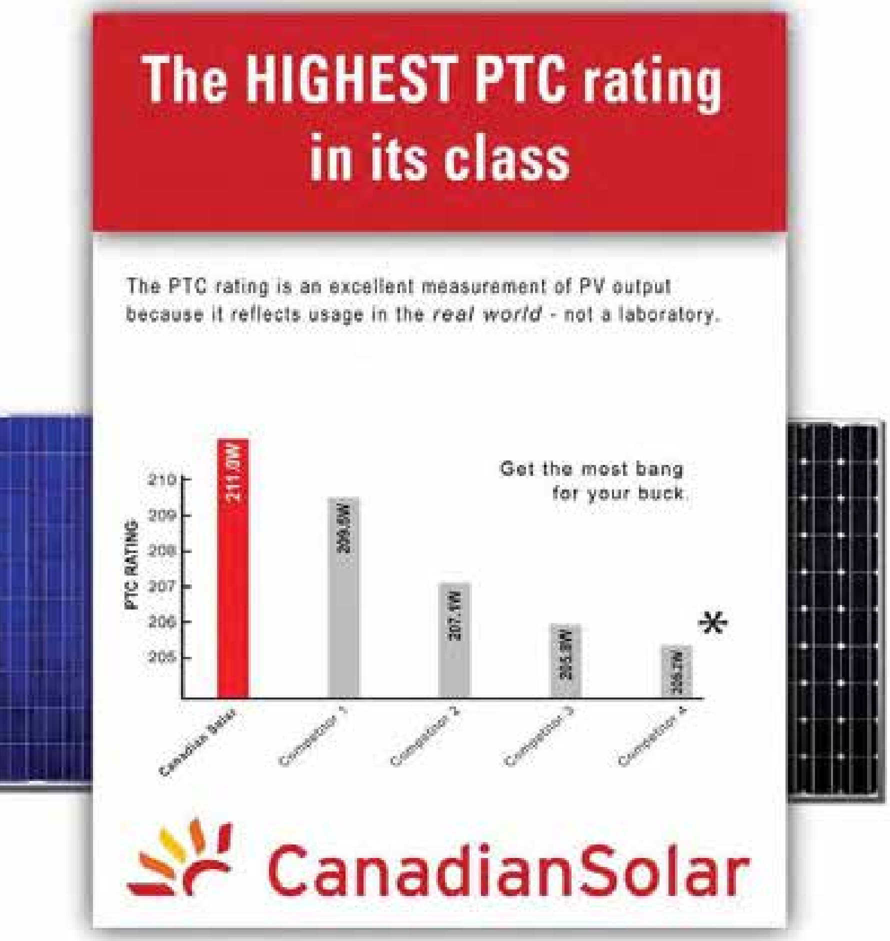

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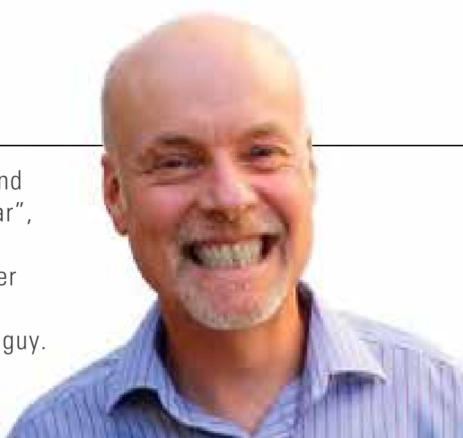


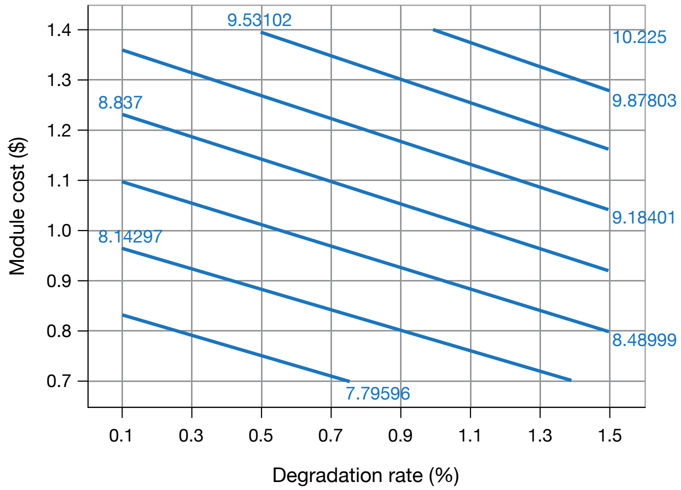
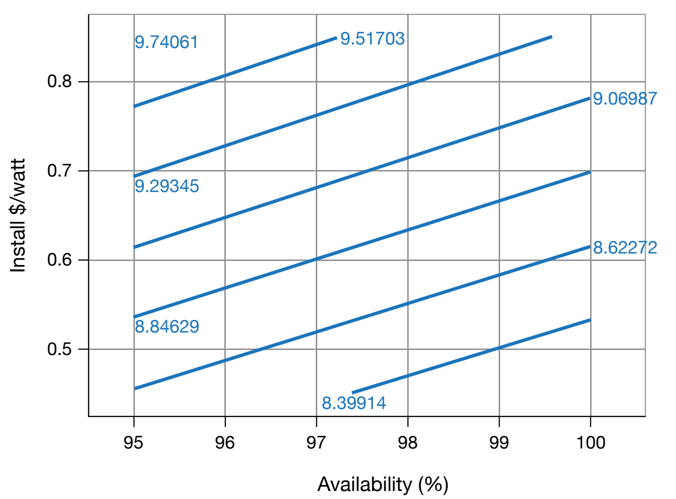


Figure 6 This chart shows the results of a parametric analysis run on the baseline fixed-tilt PV system in which module cost and module degradation rate were varied.



Courtesy Borrego Solar (2)

Figure 7 This chart shows the results of a parametric analysis of LCOE for the baseline fixed-tilt PV system in which installation costs and system availability were varied. Note that the analysis does not account for repair costs or potential damage to the installation company's brand associated with system downtime.

LCOE Sensitivity

The PV industry's continued growth and development depend on further reductions in PV LCOE. With this in mind, it is important to know which factors have the greatest influence on the LCOE equation. Where should energy be spent to find additional savings? What should we focus on to optimize systems for the lowest LCOE? What types of incentive or government-sponsored programs would be most effective?

Looking at the basic equation, it is clear that the two primary drivers of LCOE are energy production in kWh and system cost. However, each of those factors is determined by several subfactors, some more obvious than others. You can gain a better understanding of LCOE by running a sensitivity analysis. This analysis allows you to define a range of possible values for the inputs that determine LCOE. In a sensitivity analysis, a single input is varied within a specified range while all other inputs are held constant. The results of the analysis can be presented in a tornado chart such as the one shown in Figure 8 (p. 46). In this type of chart, the larger the bar, the greater the effect on the LCOE for that variation in the specific input.

Figure 8 shows a sensitivity analysis for the baseline 1 MW fixed-tilt system described in Table 1. What is immediately clear is that many of the inputs that have the greatest effect on LCOE are related to system financing. A change in the debt fraction or in the assumed discount rate can have nearly as large an impact on LCOE as a significant change in the module cost. In addition, the degradation rate has a significantly larger impact on LCOE than does system availability, even though these factors are comparable in magnitude. This is because the degradation rate compounds each year, resulting in relatively large losses in later years of the project. This analysis does not include a variation in irradiance that would result from constructing the system in different locations. However, a significant change in irradiance can have as large an effect on LCOE as the changes in the debt fraction and discount rate shown in this scenario.

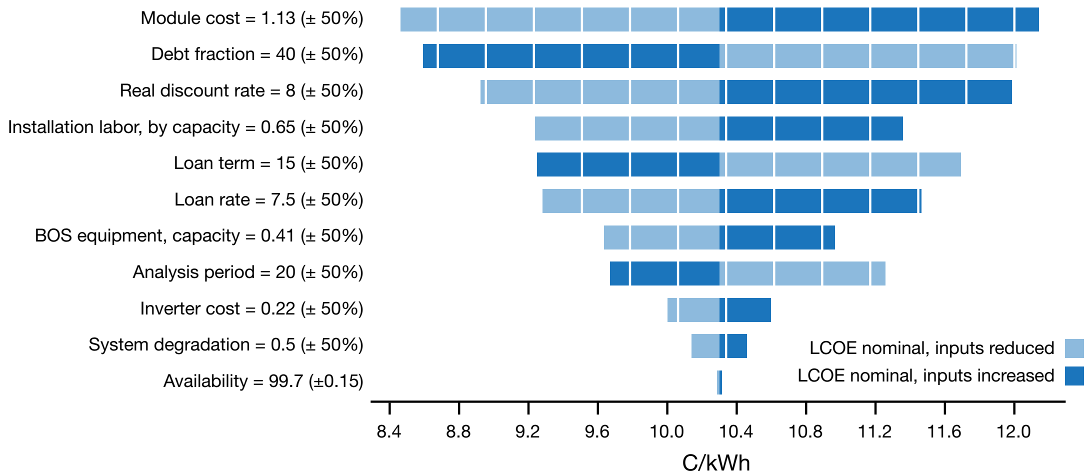
While LCOE is very sensitive to financial inputs such as debt fraction and discount rate, those sensitivities are not always relevant. When looking at big-picture comparisons that include differing technologies and risks, it is possible that different projects may be evaluated with different financial terms. Implementing new or unproven technologies may be risky. Investors may associate greater risk with these technologies, which may impact the terms of their investment. However, when considering project-specific LCOE, those inputs are likely to either be fixed or vary so slightly that the LCOE is far less sensitive to them than to location or component selection.

LCOE as a Distribution

Any analysis that assumes the values in the LCOE equation are static gives an incomplete picture. It is important to remember that many of the inputs to the equation are assumptions, the true value of which will produce a range of possible outcomes. For example, production calculations rely on variables such as weather, system availability, module nameplate rating, soiling conditions and long-term degradation rate, just to name a few. The value chosen for each of these variables as an input to the LCOE equations may be best case, worst case or somewhere in between. CONTINUED ON PAGE 46


BEYOND THE CATALOG

Figure 8 This tornado chart was created by varying the inputs to the LCOE equation by ± 50%. In the case of the availability factor, the range was changed to ± 0.15 because it is more realistic to consider system downtime varying by ± 50% rather than system uptime.



Courtesy Borrego Solar

As Seth Darling and his colleagues at the Argonne National Laboratory note in "Assumptions and the Levelized Cost of Energy for Photovoltaics" (see Resources), "Generally, LCOE is treated as a definite number and the assumptions lying beneath that result are rarely reported or even understood." The authors suggest that the end result of an LCOE calculation should not be a single fixed value, but rather a distribution—a range of possible outcomes with a probability of occurrence assigned to each one. This result can be achieved by running a Monte Carlo analysis. In a Monte Carlo analysis, probability distributions are defined for each of the input variables, and results are achieved by running numerous versions of the calculation, each time randomly picking a value for each input variable based on the probabilities defined in the distributions.

One interesting takeaway from the paper written by Darling and his colleagues is the idea that some projects have a tighter range of possible LCOE outcomes than others. This range could be determined by the consistency and quality of the weather data in that location, the certainty in the financing assumptions, the track record of the technology or any number of factors. An investor may choose to green-light a project with LCOE values that are centered on a higher number than another project's, but with a tighter range of possible outcomes.

Limitations of LCOE

According to Chris Cameron, recently retired from Sandia National Laboratories, "A common misconception is that the project with the lower LCOE is always preferred." LCOE is a good tool to use to study technology options and design decisions from a macro perspective. However, it is not always the most useful metric when making decisions about specific projects. Holt and his colleagues note in *A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies* that LCOE is "not recommended for selecting among mutually exclusive alternatives." Instead, one needs to determine the goals of the project and make decisions based on those factors.

Take the example of a cash purchase system built on a flat warehouse roof where you can build either a smaller system with a 20° tilt or a larger system with a 5° tilt. An LCOE calculation may indicate that the 20° tilt system has the lower LCOE. However, depending on the customer's load and the rate that the customer is paying for power, the 5° tilt system may save more money over the long run and may be the better option. In this scenario, a net present value calculation would be the more appropriate metric for evaluating which option to choose.

While the LCOE metric is great for calculating how much each kilowatt-hour costs over an analysis period, it does not provide a method to account for how valuable the power is. For example, an LCOE calculation does not take into account time-of-use or time-of-delivery factors, which place different values on electricity. In many situations, the financial picture looks different once these factors are considered. LCOE does not account for the reliability of the power produced by a project, either. A coal-fired power plant can generally be relied on to supply a set amount of power and a natural gas "peaker" plant can be brought on line when needed; however, renewable sources of power are inherently more variable. LCOE does not capture the cost of this variability.

LCOE Is Only One Piece of the Puzzle

LCOE can be a valuable metric in evaluating a PV system and can help engineers, developers, policy makers and manufacturers make informed decisions. However, many other parameters influence whether to invest in a project. Those parameters are often financial but may also be qualitative or regulatory in nature.

Multiple factors may increase the LCOE on a project. For example, an architect's aesthetic may result in a less visible, lower-tilt system, or a building owner's energy-offset goal may push toward maximizing a CONTINUED ON PAGE 48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LCOE and Technology Grid Parity

Nat Kreamer, CEO, Clean Power Finance

Power markets are complex. Measuring a generation type's power market competitiveness using an LCOE analysis does not give a complete picture of grid parity. LCOE makes too many assumptions and leaves out too many critical market factors.

Consider the example of the 548 MW Conowingo Dam, which is one of the largest hydroelectric facilities in the PJM Interconnection power market (covering 13 states and the District of Columbia) and is the transmission organization's black-start facility. My great-grandfather helped build the dam. LCOE can explain the discounted cash flow (DCF) value for Conowingo, provided that one assumes a constant weighted average cost of capital and a consistent water flow. Both of these assumptions, however, are erroneous. Different investors have different capital structures (debt and equity) and risk profiles (beta), which means that Conowingo's DCF value varies among investors, even if one assumes that the Susquehanna River's flow remains constant. Since river flow above the dam determines the potential nameplate capacity factor for Conowingo on any given day, this defines the productive capacity of the facility, effectively determining how much power can be amortized over the dam's capital and operating costs. Water-level volatility, much like commodity price volatility for natural gas, irradiance volatility for solar, and wind-speed volatility for wind, changes the LCOE for Conowingo on a daily basis.

The value of a fuel type—determined by its power content and availability, among other factors—and the prices paid for the power it generates is described as a *spark spread.* A spark spread is the combination of two-option values. LCOE assumes that the value of this spread option remains constant, because LCOE does not account for the forward power prices in a market. Imagine buying Conowingo Dam today with a fixed-priced, 20-year PPA with Baltimore Gas & Electric. If power prices in PJM go up, then the value of the PPA decreases for the owner and increases for the buyer (the buyer can purchase fixed-price power from Conowingo and sell it for more in the market) and vice versa. LCOE does not account for the significant amounts of money made and lost trading spark-spread options.

Conowingo also has real-option value that LCOE does not capture. If the PJM market experiences a blackout, then Conowingo turns the grid back on. Black-start services are a valuable call option, and each US wholesale power market recognizes and pays for them, yet LCOE does not account for power-market real options like black-start services.

All power markets—wholesale grid and distributed retail—are the sum of the value of all the power plants in them, which include all generation types. Because LCOE makes broad assumptions about capital costs and fuel price value while failing to account for option value, it is very difficult to determine LCOE for grid power. Consequently, comparing LCOE for solar to LCOE for the grid tells only part of the story.

system's absolute energy generation (kWh) rather than specific performance (kWh/kWp). Incentive structures, such as an up-front capacity-based incentive as opposed to a performance-based incentive, may drive system size up but performance down. Utility caps on ac system size may encourage a system design that maximizes total energy generation rather than specific performance.

Other financial considerations that play into investment and design decisions span from metrics such as the simple payback period through more-sophisticated systems such as net present value or internal rate of return. Each of these may drive a project in a different direction than an LCOE metric. In addition, capital constraints may limit a project to one with a higher LCOE—for example, when a project is built with little up-front cost to the customer.

Ultimately, while LCOE is valuable in many situations, given the variability of the PV industry and the complexity of the energy industry overall, LCOE is only one of many factors that should be considered when making decisions about PV projects.

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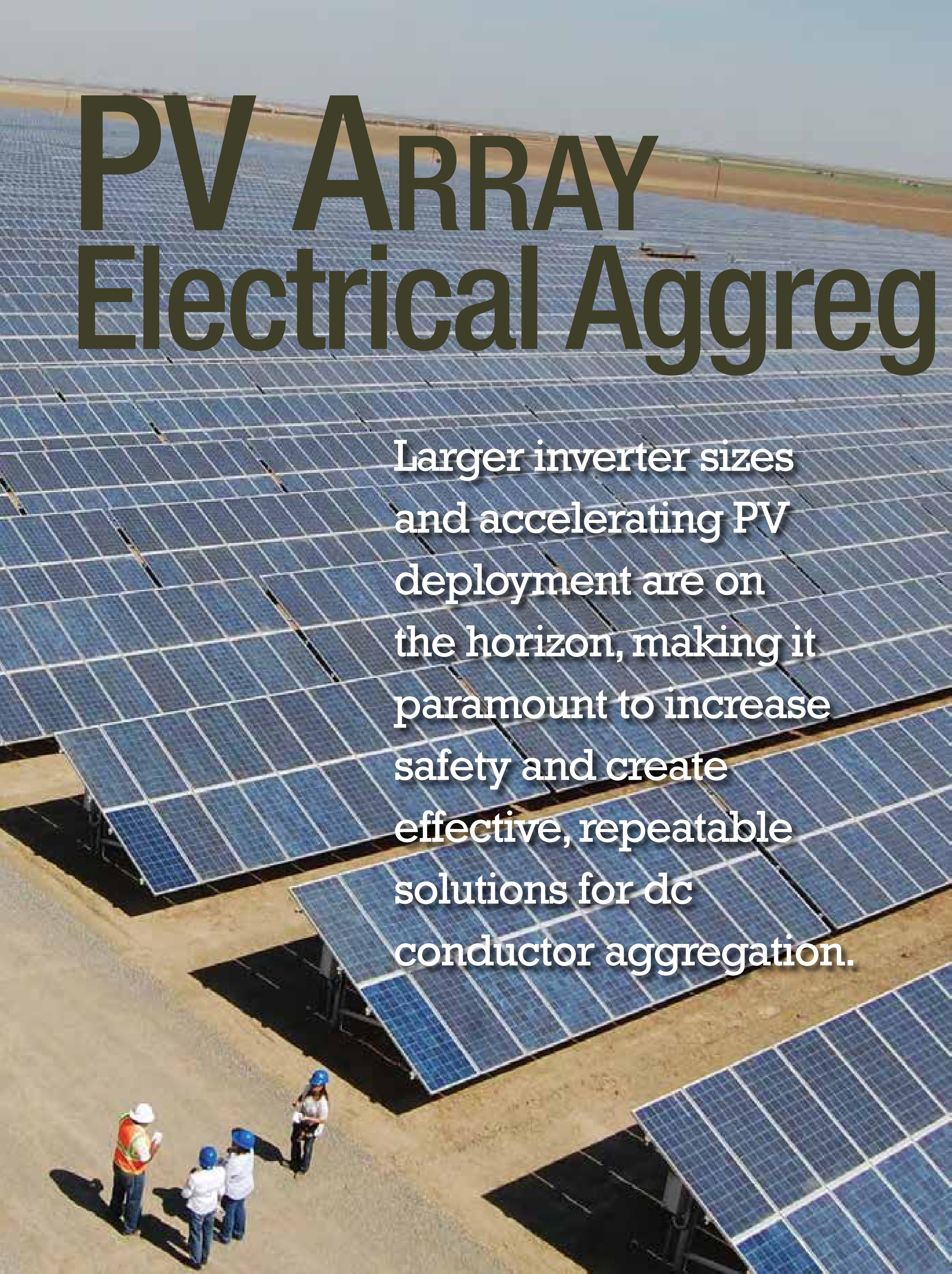
PV Array Electrical Aggreg

Larger inverter sizes and accelerating PV deployment are on the horizon, making it paramount to increase safety and create effective, repeatable solutions for dc conductor aggregation.



ation Strategies

By Tobin Booth, PE, and Matthew Seitzler

As solar modules represent a diminishing piece of overall PV system cost, dc conductors and associated dc electrical equipment represent a growing slice of the pie. Therefore, appropriate dc electrical aggregation strategies can improve cost competitiveness and innovation. At the same time, it is critical to not sacrifice safety to cut costs.

In the US, *National Electrical Code* Article 690 provides safety requirements for PV systems that serve as guidelines for designers and local AHJs. For example, the *NEC* helps system designers properly size equipment and indicates where to locate safety disconnects, fuses and other safety devices. However, the *NEC* does not help you make holistic and economical product selections. It is important to make wise and informed electrical component selection choices because safe and cost-effective solutions are vital to the industry's long-term viability.

In this article, we focus on the electrical aggregation of dc circuits in large-scale, monopolar PV arrays, which are typical of most PV systems in development today. We discuss these items within the context of the most common PV installations, namely large-scale rooftop and ground-mounted commercial and utility-scale PV systems. We explore the factors that system designers should consider when planning and developing strategies for the aggregation of a PV array circuit: safety issues, array layout geometries, equipment mechanical constraints, array combiner fusing, PV source-circuit sizing, conductor consolidation and conduit fill effects, and system installation and BOS economic considerations.

Many typical dc aggregation strategies have been implemented through the use of larger-capacity combiner boxes—as this reduces the total number of combiners—along with larger dc feeder (homerun conductor) sizes to the inverter. The rationale is simple: Buy fewer, bigger boxes; spend more on USE-2 PV Wire; and save money in the process. We would like to "peel the onion" a bit to see if these are wise design decisions. It is critical to understand the ramifications of dc conductor design choices on safety to people and property, *Code* compliance, O&M optimization and maximum array production over the life of the system.

Courtesy Blue Oak Energy

BEGIN WITH THE END IN MIND: SAFETY

While levelized cost of energy is invariably the main focus of project development, safety should be a primary design driver when considering array aggregation strategies. To ensure the safety of people and property over the lifetime of a PV system—which now averages in excess of 25 years—the design, installation and maintenance of BOS components must adhere to the highest quality standards and current industry best practices.

Rooftop fires involving dc conductor faults in PV arrays have exposed system weaknesses that need to be considered when weighing electrical aggregation strategies. (See

Figure 1 The load-break–rated disconnect integrated into this SunLink HomeRun 100 A combiner box complies with the new fuse servicing disconnect requirements found in the 2011 *NEC* Section 610.16(B).

Courtesy SunLink

"The Bakersfield Fire," February/March 2011, *SolarPro* magazine.) At the same time, you need to be aware of future *Code* requirements, like those concerning combiner box disconnection, dc arc-fault protection and personal protective equipment (PPE).

Array segmentation. When using higher-capacity combiner box sizes, and thus larger feeder sizes, as an aggregation strategy, array segmentation can prove valuable from a safety standpoint. Segmenting disconnects greatly increases safety, especially when high design currents are used. Section 690.16(B), which was added to the 2011 *NEC*, requires that disconnects be located near PV fuses and thus in the vicinity of combiner boxes. The primary role of these segmenting disconnects is to protect workers during fuse servicing.

Combiner box disconnects also allow firefighters to disconnect energy to feeders in the event of a fault. When fewer and larger combiner boxes and feeders are used, these disconnects provide an increased level of safety by separating the PV source-circuit combiners from the inverter-input combiner, which is the largest contributor to fault energy. When segmenting disconnects are used at the PV source-circuit combiners in addition to the dc disconnects required at the inverter, it becomes possible to isolate PV feeders from all current sources.

Using segmenting disconnects also allows for more-efficient O&M activities during commissioning and over the life of the system. These devices incorporate load-break–rated switches that break the ungrounded current-carrying PV output-circuit conductor, which carries current from the fused and consolidated PV source circuits back to the inverter. Opening these disconnects is a safe and expeditious way for service personnel to electrically isolate segments of and components in a PV array.

Minimum requirements found in earlier *Code* cycles (Section 690.15) required PV equipment disconnecting means at the inverter only. If just these minimum disconnection requirements were met, then service personnel would have to open the inverter disconnecting means, walk out into the array, open an enclosure that houses live circuits and then open all of the nonload-break–rated fuse holders within the combiner box to isolate the feeder or safely test individual source circuits. CONTINUED ON PAGE 54

PV-Class Fuses

Fuses used in PV systems are typically designed for ac power and control applications and listed to the UL 248 series of standards. These current-limiting fuses are generally designed to handle the higher available fault currents from the utility and have time delays built in to accommodate loads with in-rush currents, such as electric motors and transformers.

Based on the nature of the circuit they are protecting, fuses in PV systems have distinctly different requirements, particularly with respect to extreme temperatures, thermal cycling and current cycling. In addition, PV systems have limited available fault currents, and they do not include loads with in-rush currents. Due to these differences, ac-type fuses used on the dc side of a PV system can be slower to respond to a fault and thus lead to higher incident-fault energies.

To address the unique characteristics of PV systems, the UL 2579 and IEC 60269-6 standards were created to facilitate the design of dc fuses for use in PV applications. These fuses provide faster response times at the lower fault currents typical of PV systems. In some PV-class fuses, the fault sensitivities can be as low as 1.35 times the fuse rating.

UL 2579 includes specific performance tests related to PV applications that are not currently found in UL 248. These include verification of fuse-interrupting capabilities after thermal cycling, at temperature extremes of 500°C and after current cycling. At the moment, UL 2579 listings are common for class R, J, and M (midget) fuses. Similar fuse performance characteristics are used in IEC 60269. However, the fuse class designation is gPV. IEC 60269 listing is common for class NH1 and M fuses, as well as XL fuse styles.

Using PV-class fuses in place of ac fuses in subarray combiners has a minimal effect on system cost. Because they offer additional protection—like faster trip times at lower fault currents—PV-class fuses are an intelligent choice for the protection of PV feeders, especially when using an array aggregation strategy that leads to higher design currents. Inverter manufacturers, especially those with integrated subarray combiners, can increase system safety by including PV-class fuses when obtaining UL certification for their equipment.

Courtesy Blue Oak Energy

Slow blow The all-purpose ac/dc fuse used in this inverter-input combiner has time-delay characteristics that are ideal for ac power applications, but less so for PV array fault protection.


Everything
under the sun
• Complete PV electrical balance of system – residential, commercial and utility installations
• Single source supplier – simplify your engineering and business processes
• Support services – provided by hundreds of Eaton application and field service engineers
• A bankable partner – $16 billion U.S.-headquartered company backed by 100 years of innovation
• Comprehensive training – expert and regional hands-on training covering complete electrical BOS solutions
DC SWITCHING & PROTECTION
SOLAR INVERTERS
AC SWITCHING & PROTECTION

DC arc flash and PPE requirements. Section 110.16 of the 2011 *NEC* requires that equipment likely to be used for service or maintenance activities while energized be labeled or otherwise field-marked in a manner that identifies potential arc-flash energies. This requirement is intended to warn qualified persons of the electrical arc-flash hazard present and thus to identify the PPE needed to mitigate the hazard.

The Electric Power Research Institute (EPRI) and the Institute of Electric and Electronics Engineers (IEEE) have done extensive work related to ac arc flash. Out of these studies, IEEE Standard 1584 came into existence in 2002. The IEEE is currently finalizing a standard for the determination of dc arc-flash potential based upon previous IEEE analyses. While these analyses provide a framework for the calculation of arc-flash incident energy for dc applications, this standard is currently not fully defined for dc applications. *NFPA 70E: Standard for Electrical Safety in the Workplace* provides specific PPE requirements for common ac electrical equipment, but nothing is currently provided for dc equipment.

We have found that dc arc-flash incident energy magnitudes for typical 600 Vdc and 1,000 Vdc systems are more sensitive to working distances from live parts than they are to voltage and current. Because there are no clear standards on dc arc-flash calculation, we typically recommend extremely cautious arc-flash judgment for worker safety. Sometimes this requires wearing a full arc-flash suit when working on energized dc gear. However, simply wearing protective eyewear and lineman gloves is suitable in other instances.

The process of selecting the exact PPE will be improved with the introduction of PV-specific dc overcurrent protection devices, because these will increase the options available to system designers. For example, the time that a fault persists can be reduced by using dc arc-fault circuit-protection devices and PV-class fuses—which have faster trip times than all-purpose fuses (see p. 52)—allowing for lower arc-flash energy values and thus more clearly defined PPE requirements.

ARRAY LAYOUT CONSIDERATIONS

When planning PV array layouts, the physical space and the associated geometric considerations are often a starting point in the design process. The type of array layout used for a given site is dependent on factors ranging from PV source-circuit lengths to the mounting structure that will be used. In our experience, however, layout types can be divided into three distinct classes: continuous, segmented and fragmented arrays.

Continuous arrays. For the purposes of this discussion, a continuous array layout is one in which large portions of the array can be electrically aggregated using relatively straightforward wire-routing practices. An example of this layout is a rooftop array. The PV source circuits in a rooftop array can be routed almost anywhere they are needed, because they can easily cross rows and other array sections without affecting the electrical system's overall efficiency.

In a continuous array, the combiner-box footprint—the area of the array that is electrically aggregated to a particular combiner box—is not constrained by the geometry of the mounting system. This does not necessarily mean that the array is contiguous, unbroken or installed in a uniform grid pattern. As shown in Figure 2, the module layout may have to accommodate skylights, HVAC equipment, pathways required by local fire codes and so forth. However, these spacing requirements do not dictate how circuits are electrically aggregated at the combiner boxes.

As long as it is not impractical for electricians to install jumpers in PV source circuits, you can specify a relatively simple electrical design. The ability to use jumpers in source-circuit conductors effectively allows you to increase the combiner box footprint as desired. To the extent that more of the array capacity can be dedicated to each PV source-circuit combiner, then combiner CONTINUED ON PAGE 56

Figure 2 While the module layout in this continuous array is irregular and broken up to accommodate roof access and skylights, the use of PV source-circuit jumpers allows for large sections of the array to be electrically aggregated at each combiner box.

Courtesy Blue Oak Energy

box size can be increased. The result is a consistent aggregation of larger electrical subsets of the PV array.

Segmented arrays. In a segmented array, the combiner-box footprint tends to be smaller and more granular than in a continuous array. This is often a response to constraints imposed by the mounting system or shading considerations. An example of a segmented array is the ground-mounted PV system illustrated in Figure 3. Arrays mounted on carports and single- or dual-axis trackers are other common examples. In these systems, the combiner-box footprint can easily be matched to the footprint of the individual mechanical assemblies to simplify conductor routing.

While a segmented array layout may be driven by the difficulty or cost to route PV source-circuit conductors between structures, the use of a logical and granular segmentation of an array simplifies future O&M activities. In the event of a ground fault, for example, identification and remediation activities are simplified if PV source circuits can easily be traced and opened for testing. Customer preference may also dictate a finer consolidation and segmentation of an array layout. For example, some clients prefer that each tracker drive block be electrically continuous and that source circuits not be shared between other tracker blocks or rows. To the extent that more combiner boxes are distributed throughout the array, the relative capacity of each combiner can be reduced.

Fragmented arrays. In a fragmented layout, the array is not electrically aggregated in a consistent manner. This is often due to physical layout constraints that make it impossible to harmonize the electrical aggregation of the array with its support structure or mounting system. Fragmented array layouts may also accommodate an unusually high number of site obstructions: water sources, easements, shade zones and so forth. In a fragmented array layout, the combiner-box footprint is irregular relative to the mechanical layout of the array, with source-circuit conductors routed between different structures or rows to aggregate fragmented sections of the PV array.

Courtesy Blue Oak Energy

Figure 3 In a ground-mounted array like the one pictured here, it can be difficult to route source-circuit conductors between one mechanical assembly and another. Therefore, Blue Oak Energy electrically aggregated the PV source circuits in a segmented manner corresponding with the mounting system's mechanical divisions.

Installers tend to take different approaches to array fragmentation. One approach is to route PV source-circuit conductors all over heaven and earth to use every fused input to a combiner box. In addition to the potential added cost, this layout can present challenges when someone has to find a faulty or open circuit. We have seen source circuits in fragmented arrays travel some remarkable routes—running hundreds of feet in free air and underground, in conduit or directly buried—just to fully load the input fuse section of a distant combiner box. Ultimately, however, most fragmented array layouts are the result of physical constraints that are beyond the system designer's control.

While the use of a fragmented array layout can make sense in many instances, we recommend a less-is-more approach. Think about array maintenance. Before finalizing the design, ask yourself: "If I were going out into the array to locate a ground fault or an open circuit, would I be able to find it without having to do major surgery at the site?"

STRING-TO-COMBINER CONSIDERATIONS

The primary design considerations involving the aggregation of PV source circuits include equipment constraints, string sizing, string routing and voltage drop.

Equipment constraints. Successful array aggregation strategies must accommodate limitations imposed by the electrical BOS components. For example, the maximum cable size rating for input terminals at subarray combiners, inverters or service disconnects effectively limits the size of the inbound feeder conductor. Similarly, the physical size of an equipment enclosure imposes limits on the maximum allowable wire-bending radius. While it may be possible to use cable reducers in some instances, the enclosure must be large enough to accommodate the allowable wire-bending radius plus the dimensions of the reducer.

Structural considerations may also constrain equipment selection and deployment. Many buildings are intentionally designed to be “structurally lean,” meaning that additional structural carrying capacity is minimal. When this is the case, it can be problematic to introduce a rooftop PV system and the associated BOS components. For example, in a rooftop PV system with a ground-mounted inverter, a structural engineer needs to consider the structural implications of routing a large number of array conductors and conduits together. Custom racking is required in some instances to distribute the loads associated with this equipment in a manner that prevents damage to building parapets, exterior walls and the roof.

String sizing. At a fundamental level, the electrical aggregation of a PV array starts with the PV source-circuit configuration. As Bill Brooks illustrated in the article “Array Voltage Considerations” (October/November 2010, *SolarPro* magazine), this is a module-, inverter- and location-specific exercise. Regardless of whether you are using an online string-sizing tool or performing your own calculations, the acceptable range of series-connected modules needs to be based on historical weather data and the published inverter input and operating parameters.

Assuming these calculations indicate that more than one source-circuit configuration is acceptable, you can specify an odd or even number of series-connected PV modules. Even numbers of modules are generally easier to work with, simply because even numbers provide more divisibility and hence more design flexibility. This is helpful when harmonizing the electrical design with constraints imposed by a mechanical assembly with fixed dimensions.

The design parameters on one of our projects called for the use of an odd number of modules per PV source circuit. This meant that we needed to lay out groups of 11 series-connected modules atop multiple carport structures that were not uniform in size. The smaller carports, in particular, were challenging with regard to string layout and PV source-circuit wiring. The physical constraints necessitated a fragmented array layout.

While using an even number of modules is not necessarily a panacea, in this instance it would have simplified the array wiring, as illustrated in Figure 4 (p. 58). Since source-circuit sizing depends on the relationship between module voltage and the inverter’s operating voltage range, you may be able to eliminate or alleviate layout constraints by considering different combinations of components.

String routing. Source-circuit routing is another important aspect of the array layout process. While most system owners want to optimize energy production, some simply want to minimize the initial installation and material costs. When a customer wishes to maximize energy production, the design team can spend more time arranging the layout and location of PV source circuits on the racking system in a manner that minimizes shading losses. When the customer’s goal is to minimize up-front costs, string orientation is not as important as minimizing the overall length of the wire runs. The relative

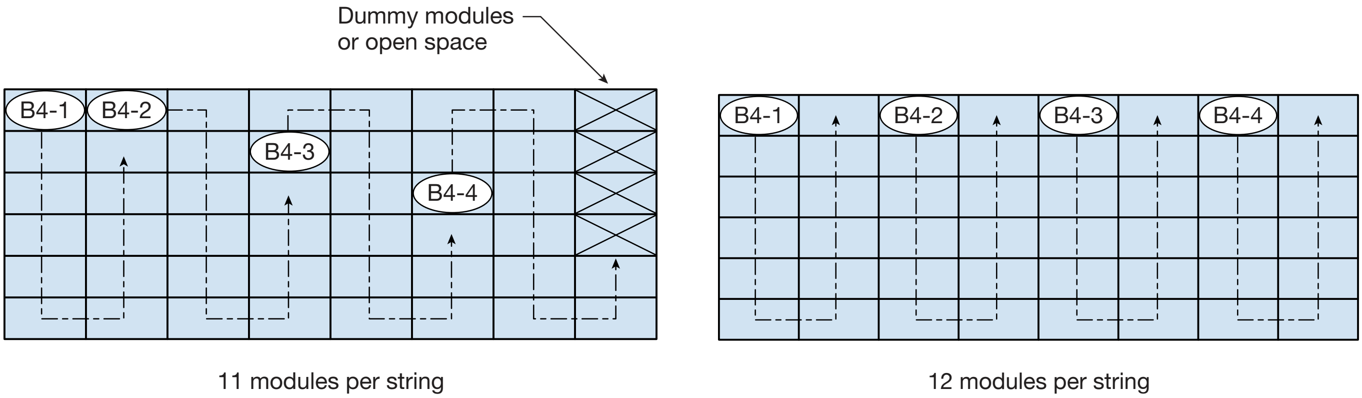


Figure 4 Because 11 is both an odd number and a prime number, it does not allow much design flexibility in relation to the carport section shown on the left. Using 12-module strings would improve divisibility and design flexibility. When the 12-module strings are configured as two columns, as shown on the right, source-circuit routing back to the combiner box is greatly simplified compared to the 11-module string layout, as are any wiring activities associated with prepanelizing individual columns of modules.

importance of each of these factors is worth considering when planning PV array aggregation strategies.

Voltage drop. A good electrical designer balances voltage drop effects and system cost considerations when determining an optimal array aggregation strategy. The intent is not to improve system efficiency at *any* cost, but rather to optimize the dc voltage drop allowance as it relates to system cost and performance. (See the QA "Voltage Drop in PV Systems," February/March 2010, *SolarPro* magazine.)

Voltage is a measure of electrical pressure. Valuable solar-generated electrons are invariably lost in any PV system due to conductor resistance, in much the same way that water pressure is lost due to friction in a pipe. The total percentage of voltage drop in PV circuits is a summation of the percentage of voltage drop in the string-to-combiner conductors and in the combiner-to-inverter conductors. Therefore, it is useful to consider how different array aggregation strategies influence the proportion of the allowable voltage drop percentage that is incurred in each of the circuits.

For example, when system designers distribute a larger number of smaller-capacity combiner boxes throughout an array, then the dc voltage drop incurred in the PV source circuits is generally less than it would be if fewer and larger combiner boxes were used. With a more granular distribution in the field, it is possible to locate the combiner boxes physically closer to the aggregated PV source circuits. Conversely, the use of larger combiners generally means that more voltage drop is incurred on the PV source-circuit conductors, because the larger combiner-box footprint requires longer wire runs. Whichever strategy you employ, you need to ensure compliance with overall voltage drop design constraints.

The logical choice with respect to circuit length would be to locate all of the combiners and inverters within the array field—as we did with the system shown in Figure 5—to reduce the length of the dc feeder runs. In practice, this is sometimes beyond the system designer's control. For example, rooftops often have structural loading constraints that require inverters to be on the ground; PV carports CONTINUED ON PAGE 60

Figure 5 Locating inverters and combiner boxes within the array field reduces the length of the dc feeders, which reduces the need to upsize conductors to account for voltage drop.

Courtesy Blue Oak Energy (2)

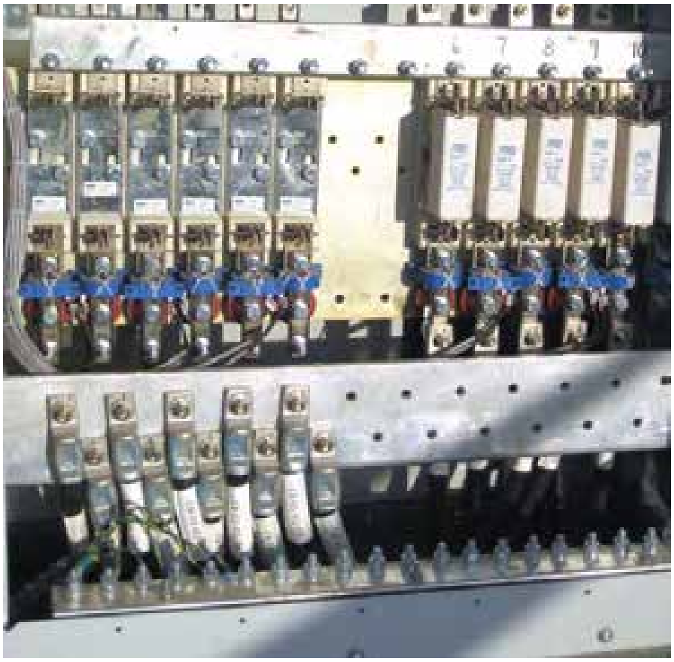
have to accommodate dual uses (power generation and parking), which may result in large distances between arrays and inverters.

Exceptionally long wire runs can prove challenging. The maximum size of the feeder conductors is effectively limited by equipment compatibility at the subarray combiner. One technique for reducing voltage drop without increasing feeder size is to reduce the number of PV source circuits aggregated at the combiner boxes located farthest from the inverter-input combiner.

Even though PV system designers typically use module STC ratings for design calculations, these are not the best values to use for voltage drop calculations. A PV array operates at its rated maximum power only under specific conditions and at certain times of the year. Rather than design for a maximum instantaneous voltage drop in the PV array—such as 2% voltage drop at maximum power conditions—the design intent is to limit the overall percentage of annual voltage drop losses.

The best way to calculate the year-round percentage of voltage drop losses is to use a simulation program like PVsyst. If this is not an option, consider using 80% of the array operating current (Imp) along with the nominal operating voltage (Vmp) in design calculations to estimate the annual percentage of voltage drop losses. While many in

Figure 6 This inverter-input bus allows for the use of single-hole compression fittings on the array feeder conductors. This not only accommodates a wide range of conductor sizes, but also simplifies future maintenance activities.



Courtesy Blue Oak Energy

the industry use 2% voltage drop as a de facto design standard for the dc side of a PV system, this practice is subject to review based on conductor costs and the price the utility pays for PV-generated electricity.

COMBINER-TO-INVERTER CONSIDERATIONS

The primary goal of any array aggregation strategy is to collect all the PV output-circuit conductors at the dc input to the inverter. With regard to these feeder conductors, the two main design considerations are fuse sizing and conductor routing.

Fuse sizing. *NEC* Section 690.9 requires fuses at inverter-input combiners (or at external subarray combiners) to provide overcurrent protection from all current sources. The intent is to limit current backflow through the collection system to the source-circuit combiner boxes. There are several potential causes of reverse or backfeed current in a PV array, including incorrect combiner box wiring, lightning events, insulation faults and human error during commissioning or O&M activities. Fuse protection is essential for ungrounded current-carrying feeder conductors.

While stand-alone subarray combiners are available, most modern inverters offer integrated fused inputs. When planning array aggregation strategies, the fuse sizing options that are available from the manufacturer often become critical design drivers. The associated maximum and minimum fuse sizes are particularly relevant because they determine the number of inverter input circuits, the size of the feeder conductors and ultimately the number of PV source circuits that can be dedicated to each combiner box. (See “Central Inverters for Commercial PV Applications,” December/January 2012, *SolarPro* magazine, and “DC Combiners Revisited,” February/March 2011, *SolarPro* magazine.)

Mechanical termination is another important consideration. Many inverter input combiners have mechanical lugs that accept a specific range of conductor sizes, which limits design flexibility. Fortunately, inverter manufacturers have recently begun to recognize the wisdom of accommodating terminations using single- or double-hole compression fittings. An example of this type of termination method is shown in Figure 6. In addition to reducing the maintenance requirements at the inverter—such as eliminating the need to periodically retorque mechanical lugs—compression fittings tend to accommodate a wider range of dc feeder sizes, a feature that system designers value.

Conductor routing. Conduit fill temperature effects are important to consider when deciding how to physically route aggregated PV circuits back to the subarray combiner. When combiner boxes are deployed in a more granular fashion—using a larger number of smaller-capacity combiners—it is often tempting to consolidate multiple PV output circuits into a single raceway. However, doing CONTINUED ON PAGE 62

so decreases conductor ampacity—as shown in Figure 7—according to the adjustment factors found in *NEC* Table 310.15(B)(3)(a).

Because PV source circuits are often routed in free air, they are generally not subject to conduit-fill adjustment factors. However, conduit-fill effects must be considered whenever multiple dc feeders are consolidated into one raceway and whenever paralleled sets of circuit conductors are used in place of larger feeders. As illustrated in Figure 7, an 80% adjustment factor is required whenever two cables are paralleled per current-carrying conductor in a PV feeder. If four cables are paralleled per current-carrying conductor, then you must adjust conductor ampacity by a 70% factor.

Applying these adjustment factors to paralleled sets of conductors translates into an increase in the cross-sectional area of copper per current-carrying conductor. Increasing the conductor area can be a useful way to limit voltage drop according to system design criteria. To avoid incurring further adjustment factors, some installers prefer to dedicate large paralleled sets of conductors to a single conduit. A secondary benefit of this approach is that having just one circuit per raceway also makes it easier to isolate any faults.

Especially on large ground-mount PV systems using larger feeder sizes, you need to consider heat transfer effects between underground dc conductors. Soil and air have very different insulating properties. Site soil resistivity is a critical component of heat transfer, since it indicates the extent to which soil properties will resist the flow of electricity and create a voltage drop or a heating effect in the conductor. Soil-resistivity measurements are necessary to design an efficient underground electrical system, ensure adequate conductor spacing and minimize conductor ampacity reductions. Knowledge about soil resistivity and how it varies across a site is also essential to the proper design of the electrical grounding system, especially for a site with a substation.

For ground-mounted PV systems in general, aggregation schemes that reduce the length and width of the trenching runs are beneficial. These schemes not only help control costs, but also reduce site disturbance, which can be a hard limit to the development of some sites.

ECONOMIC CONSIDERATIONS

In practice, PV system design decisions are usually driven by economic considerations. As such, the aggregation strategy for each PV system should be analyzed to identify potential reductions in installation material and labor cost. The best approach is often site specific and influenced by the cost of material and labor at the time the project is being developed.

Conductor costs. While there are many aspects of array aggregation that have economic implications, conductor cost is a major factor. As module prices continue to fall, conductor selection has an increasing impact on overall project economics.

Given that conductor ampacity and cost are both dependent on wire size and material, it is only logical to ask, "Is there a conductor size and material that provides the most ampacity per dollar?" If so, then knowing what this is can help you make the most economical design decisions. For example, system designs could be standardized around the most cost-effective conductor choices.

The first step in this analysis is to determine the specific cost per rated amp for a typical range of PV array conductors, based on the ampacity ratings found in the *NEC*. In Figure 8 (p. 64), for example, we have plotted the relative cost per ampere ($/A)—based on *Electrical Cost Data* estimates published by RSMeans in 2011—for 100-foot lengths of cable ranging in trade size from 2 AWG through 600-kcmil. We did not consider smaller cable sizes because they are generally not used for feeder conductors in commercial and utility-scale PV arrays. In addition, we did not consider 700-kcmil conductors due to their prohibitive cost and high labor requirements.

While the cost per ampere in Figure 8 increases along with conductor size, something more interesting is revealed when you compare these incremental cost increases. What is the specific cost increase per ampere to upsize a conductor by one standard CONTINUED ON PAGE 64

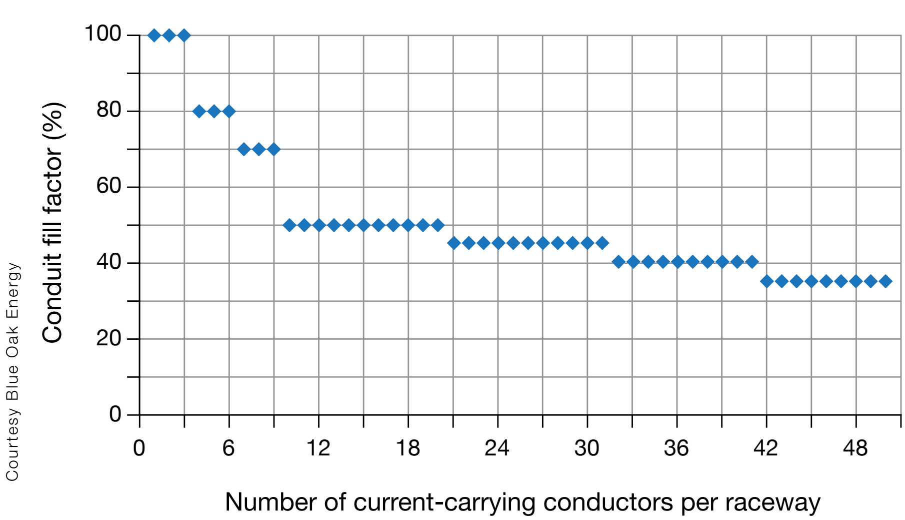


Figure 7 As the number of current-carrying conductors in a raceway is increased, the ampacity of the conductors needs to be adjusted according to the factors found in *NEC* Table 310.15(B)(3)(a), as summarized in this chart.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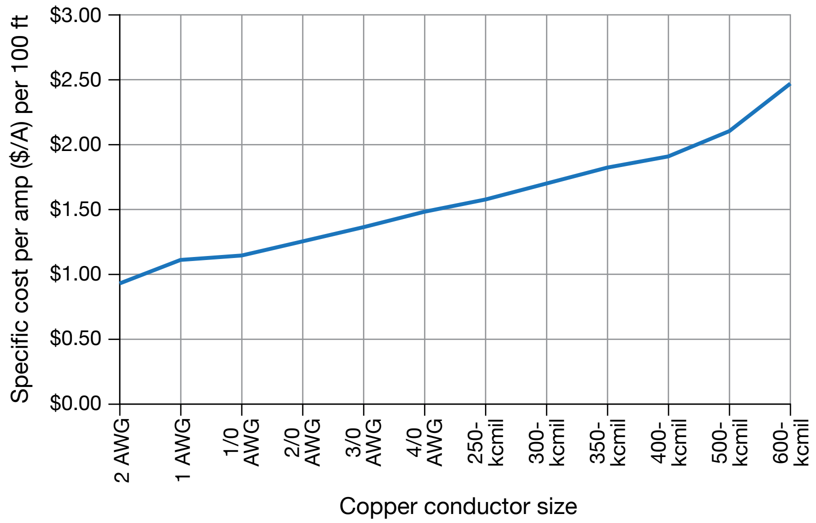
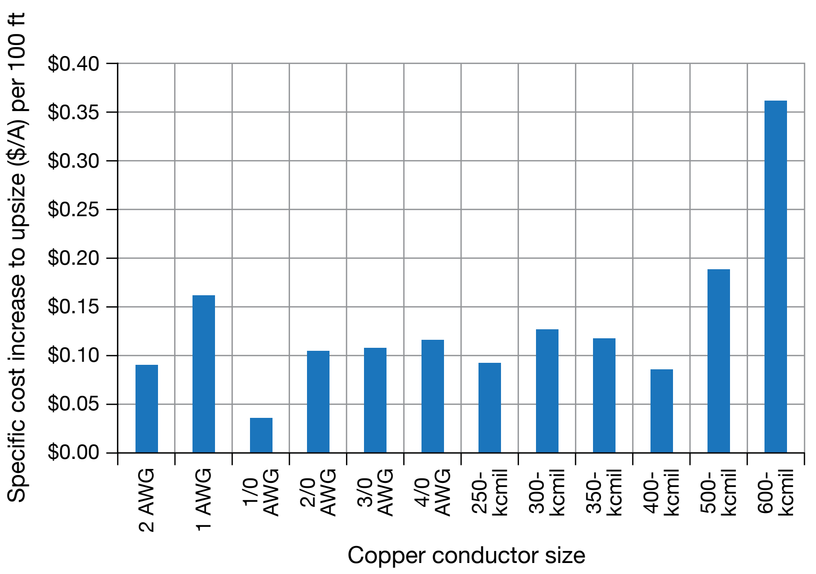


Figure 8 This graph shows the cost per ampere for 100-foot lengths of typical copper conductor sizes used for PV array feeders.



Courtesy Blue Oak Energy (2)

Figure 9 This graph shows the relative increase in the specific cost per ampere associated with upsizing copper conductors.

trade size? Knowing this, you should be able to make informed decisions about when it makes sense to upsize conductors to increase current-carrying capacity and reduce voltage drop.

The results of this comparative analysis are shown in Figure 9. For calculus lovers, this graph is the derivative of the graph in Figure 8. One of the things that stands out in Figure 9 is that upsizing to 1/0 copper conductors incurs the least cost increase per ampere. For example, using 1/0 over 1 AWG saves roughly $0.12 per ampere per 100 feet of conductor; using 1/0 over the more common 2 AWG provides savings of $0.05 per ampere per 100 feet of conductor.

This is just one example of an economic analysis relating to array aggregation. A similar analysis can determine whether it makes economic sense to switch from copper to aluminum feeder conductors.

Reducing costs. One common array aggregation strategy is to reduce the quantity and variety of BOS components in an effort to drive down material costs. From an engineering standpoint, this is achieved by designing the system using a standard set of components, while still maintaining *Code* compliance and meeting minimum design standards. This could be achieved by using larger combiner boxes with larger feeders to reduce BOS costs. While this approach may leverage some economies of scale, it is not necessarily the best design approach overall. You need to determine whether the choice of components leads to additional labor costs, and, if so, whether these outweigh the material cost savings.

Another common approach to array aggregation is to emphasize installation labor cost reductions. Labor can be a significant portion of project capital costs, and many installers actively seek out the system designs that are easiest to implement. For example, if additional pull boxes are used—beyond those required based on conductor pull lengths or the allowable bends in a raceway—material costs increase. However, labor costs are reduced because it is easier and faster for installers to pull the conductors.

The challenge for PV system designers and developers is to find the balance between material and labor cost reductions that ultimately results in the lowest cost overall. Our contention is that for most PV systems, a wise and holistic balance of the approaches we have outlined in this article typically produces the safest, most repeatable and most economical solution.

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Residential Solar Site Measurements: New Developments

By Peter Hoberg

Courtesy Solmetric (2)

As the PV industry has matured, the expectations for accurate measurements have been ratcheting up. Increasingly, for the solar installer, competitive pressure to reduce cost of sales and BOS costs must be balanced with the financing companies' requirements to provide accurate up-front site measurements, design estimates and energy production guarantees. The industry's tools and best practices are evolving and maturing to keep pace. Here I describe recent developments and trends, including tools and best practices for measuring roof dimensions and shade, estimating system performance, and evaluating the impact of solar leasing options and performance guarantees on site measurement approaches. In addition, I address when, where and how the available technologies are most appropriately applied to help balance the needs of the different stakeholders associated with a PV system.

Stakeholder Perspectives on Site Measurement Accuracy

Throughout a typical residential PV system sales and installation life cycle (see Figure 1), the various stakeholders have different motivations and perspectives with regard to the accuracy of site measurements and the corresponding system performance estimates and guarantees.

Homeowner. Homeowners invest in solar energy because they want to reduce their energy costs and do so without adding new hassles and headaches. Their primary metric is their monthly electricity bill, before and after the installation, combined with any new financing payments. They may also want to view the system's instantaneous or historical performance with a simple web interface or smartphone app. The method the homeowners use to finance the system may also influence how they view the measurements and performance. If they own the system, they want optimum production and may be concerned about ongoing maintenance. If they have a solar lease with an energy production guarantee, they may want to compare energy production to the guarantee and may not be as concerned with optimizing production.

Installer. The company responsible for selling, installing and maintaining the system typically feels pressure to close a sale quickly, with moderate and predictable costs. The inside salesperson's goal is to close a sale over the phone. The outside salesperson attempts to close on the first site visit. Either way, sales representatives require accurate roof parameters and shade measurements so they can perform accurate system sizing and energy production estimates for the sales quote. After the sale, often an auditor or designer performs a more detailed on-site evaluation and makes any required adjustments to the initial design and system performance predictions. After installation, the installer wants assurance that the system performs to expectations within the warranty and/or performance guarantee period. Ultimately, the installer wants satisfied customers and minimal long-term risk to ensure repeat business and financial success.

State and local governments. In recent years, state programs have driven many of the industry's best practices for site measurements. Public accountability and political pressure to ensure that subsidized systems meet a minimum quality and performance standard have led to the development of required procedures for installers. For example, many of the leading states that support solar energy have solar access measurement requirements for their incentive programs. Some programs require that the proposed PV system meet a minimum solar access value, while others adjust the incentives in proportion to the available solar access.

State or utility programs that pay an up-front incentive based on system capacity often adjust the incentive to include shade values. In some programs, 10% shade means a 10% reduction in rebate value. The California Solar Incentive, for example, prorates the rebate based on the amount of shading. Frequently, the financial impact of shading is reflected in the actual energy production of the installed system to a greater degree than in the rebate payment.

Solar financing company. With the dramatic rise in third-party financing in the form of solar leases and power purchase agreements (PPAs), there has been a significant shift in the dynamics of residential site measurements. Financing companies and their investors want to optimize financial returns while controlling risk. Site measurements are supplied by the installer and are critical to determining the project's financial success. Increased measurement accuracy improves predictability and reduces guard bands built into the investment model to account for system performance variability, thus allowing for better all-around terms for the investor, the

Courtesy SolarTech

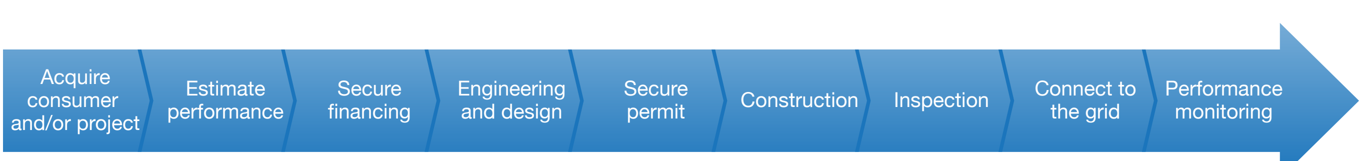
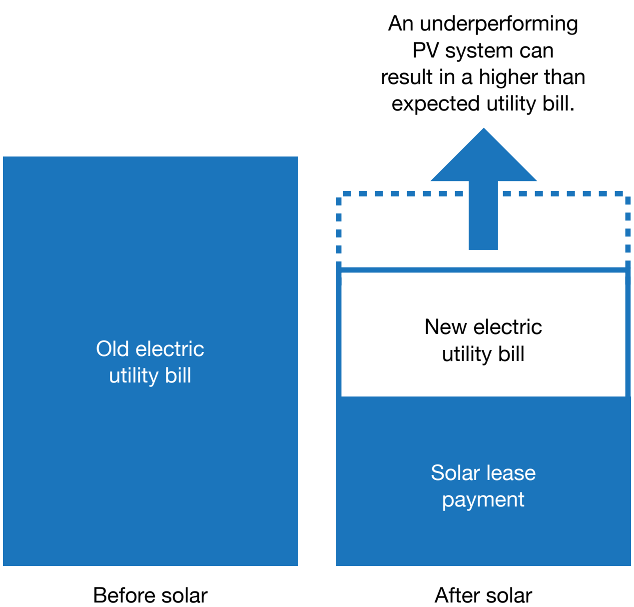


Figure 1 Solar project milestones are identified in this timeline developed by SolarTech. Site measurement accuracy impacts most of the stages of project development, from customer acquisition through measurements that verify performance over a system's operational lifetime.

installer and the customer. Better terms, such as lower interest rates, favorable performance guarantees and lower baseline energy rates, enable an attractive offering that helps win the deal by reducing the customer's payments and providing an assurance of energy production.

Figure 2 shows the typical scenario presented to customers for a residential lease or PPA. This scenario depends on the installation and operation of a high-performing PV system. If the system underperforms, then the utility bill is greater than expected, falling short of customer expectations and possibly the performance guarantee. Site measurement plays a key role during the sales process in determining the correct production estimate and performance guarantee values.

"The need for accurate shade reports and production estimates has increased tremendously, since residential lease and PPA companies are guaranteeing a production estimate for the life of the contract. Shading can greatly affect the kWh/kW of a system's output, and needs to be accurately accounted for at the time of contract."—Kareem Dabbagh, SunRun



Courtesy Solmetric

Figure 2 Accurate site measurements affect production estimates, performance guarantees and ultimately customer satisfaction. For residential projects with a solar lease or PPA, underperforming systems will result in higher than expected utility bills and possibly performance guarantee penalties.

Remote vs. On-Site Measurements

All stakeholders agree that accurately measuring a roof's pitch, orientation, dimensions and solar access is critical. The key question that remains is: When in the process should accuracy be maximized?

Consider solar access. Shading has a significant impact on the production of a PV system (see "Sun Paths and Shade Impacts," p. 78). Since financial return on the investment in a PV system is typically tied directly to energy production, shading clearly reduces the value of a solar asset. For example, in a net metered system, shading results in lower offset energy costs when on-site consumption is high, and less energy sold back to the grid when on-site consumption is low. Similarly, shading reduces the value of a PPA and production-based incentives such as solar renewable energy credits (SRECs) and feed-in tariffs (FITs) over the life of the system.

An estimate of the shading at a particular site can be obtained by looking at aerial photos on the web or by using an aerial photo mapping service. The cost can be less than it is for rolling a truck, climbing on the roof and making measurements on-site, but the trade-off is accuracy. Remote measurements can be useful in the presale stage, but verifying and correcting the initial estimates with actual on-site measurements is critical to make an accurate production estimate.

The challenge for installers and investors is to strike the right balance between minimizing the cost of sales and maximizing the accuracy of the production forecast. If integrators spend too much time up front collecting and recording site measurements, optimizing the system design and refining the performance estimates, they risk wasted efforts in the event that the sale does not close. If they do not spend enough time, there is an elevated risk that the proposal will not represent reality. If the proposal underpredicts production, money is potentially left on the table. If it overpredicts production, and this is discovered *before* installation, the contract may need to be revised, resulting in extra work and an unhappy or lost customer. If it overpredicts production and this is not discovered until *after* installation, the installer may end up paying production guarantee penalties. Somebody always loses when production is not accurately predicted. Measurement accuracy reduces risk for all stakeholders.

Kevin Myers, fleet manager of Clean Power Finance, a provider of software solutions that connect installation professionals with financing options, expresses the solar financing company's point of view: "Performance guarantees go hand in hand with leases and PPAs, and these CONTINUED ON PAGE 70

guarantees must be built upon data and accurate site and system parameter inputs in the production estimation phase of the project."

The relationship between site measurements and production estimates and guarantees is illustrated in Figure 3. Accurate on-site measurements can reduce the uncertainty inherent in estimates, guarantees and guard bands, increasing the sales bid's competitiveness and reducing the project's risk. The trade-off is increased time or measurement-tool cost and therefore increased sales costs.

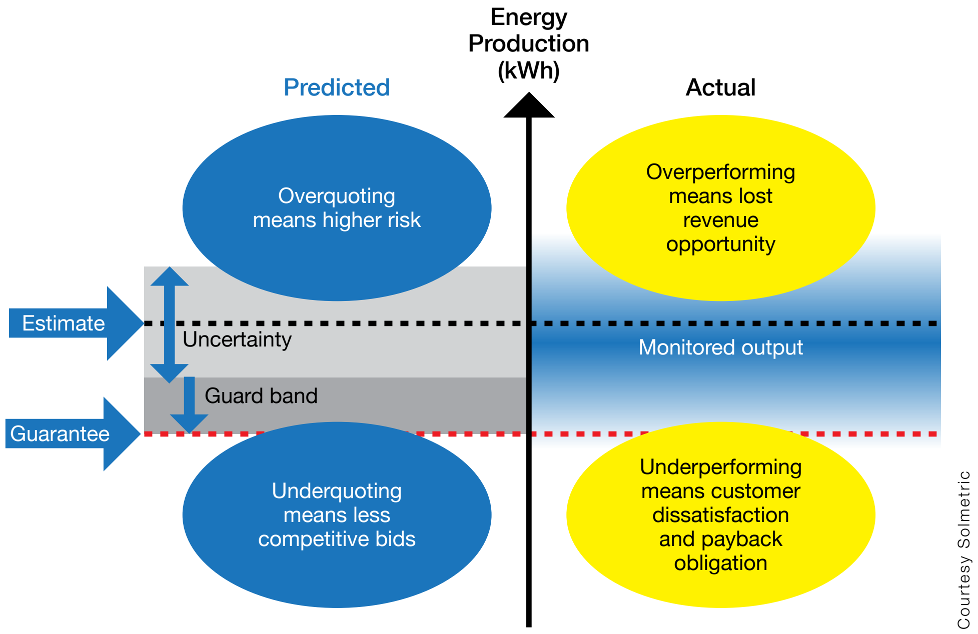


Figure 3 Inaccurate site measurements increase energy production estimation uncertainty. Overquoting production creates higher risk, while underquoting production results in less competitive bids and lost business opportunities.

There is no one formula that works in all cases to determine whether a sales proposal requires a presale on-site visit. Different installers have different business philosophies. Many installers always go on-site and make detailed measurements before generating a sales proposal so they know that they can actually build what the customer is signing up for. They also feel that the in-person customer contact makes closing the sale more likely, so the higher closing rate offsets the higher cost of obtaining the sale. Others try to win the sale without a site visit and then follow up with the detailed measurements later, accepting the risk that the site visit may uncover issues that force changes to the design. There are risk and reward trade-offs with either approach.

"We are now able to sell or lease a system before visiting the house," comments Mateo Williford, a technologist at Sungevity, a solar lease provider. "Once a system is sold, we do a site visit. It is important that the on-site measurements are accurate so that we can confirm the system that we designed remotely." Jerry Shafer, CEO of Affinity Energy, a PV and solar heating integrator based in Windsor, California, advocates doing a site visit before selling the system. "There is no substitute for getting your feet on the site and looking for yourself," he says.

> "The use of Bing Maps, Google Earth and Pictometry has increased the efficiency of the sales process and has enabled solar sales firms like One Block Off the Grid to scale quickly into new markets. The use of aerial images does not impact the need for measurements on-site, however, because there still needs to be a verification process."
>
> —Ryan Mazelli, One Block Off the Grid

REMOTE EVALUATIONS VIA ONLINE IMAGERY

The widespread availability of aerial images from Google and Bing brings new tools to the solar sales process (see Resources). Integrators can use aerial images to determine approximate roof size and identify any showstoppers before visiting the site. In addition to aerial images, a variety of related services are available to help solar firms prospect, qualify and develop solar opportunities.

"It's typical for contractors to pull up imagery like Google Earth while on the phone with a client," states Brian Farhi, vice president of marketing and business development for SolarNexus, a supplier of software for solar business and operations management. "This provides a first pass at whether a roof is suitable," he continues, CONTINUED ON PAGE 72

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Jono Stevens, VP Operations, Cobalt Power Systems

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Online Tools for Roof Measurement and Layout

A variety of online tools can help users perform basic and advanced system sizing, array layout and in some cases energy production estimates. These tools give users the ability to make measurements on top of the aerial images.

Clean Power Finance (CPF). CPF Tools is an advanced solar proposal service with a roof measurement tool that characterizes roof shape, dimensions, tilt and azimuth. Additional features enable string sizing, array layout and financial modeling.

Google SketchUp. This online 3D drawing program provides a complete CAD environment, a rich library of images and advanced capabilities for shade visualization. Solar software suppliers have added a variety of capabilities by developing SketchUp plug-ins to enable drawing buildings and obstructions. Examples include Bright Harvest Solar and Skelion. In addition, Google Building Maker enables convenient drawing of a 3D building. (This is currently available in only some locations.)

In My Backyard (IMBY). Developed by the National Renewable Energy Laboratory, IMBY is a solar simulation tool that allows the definition of array area on an ortho image, and then enables basic PV system calculations including energy production modeling.

Courtesy Bright Harvest Solar

3D visualization Solar software providers like Bright Harvest Solar have developed free plug-ins that can be used for preliminary array layout within the Google SketchUp 3D drawing environment. Bright Harvest also offers more-detailed roof and array drawings and layout modeling for a fee.

"and allows the contractor to ask the customer some targeted questions to rule potential designs in or out. However, an onsite assessment is eventually necessary prior to finalizing any designs, since imagery can be out-of-date or can fail to show all the necessary details."

Common image perspectives. Online images are available in different forms and resolutions depending on a site's location. The following are the three most commonly used.

- **Orthophotos:** Often referred to as *ortho images* (see Figure 4, p. 74), orthophotos are projected onto a map to appear vertically overhead from all locations on the map. This imagery is available throughout the US, but image quality varies.
- **Oblique images:** These images are taken from off-vertical angles and from multiple directions, as shown in Figure 4. Currently, Bing Maps offers free oblique images from north, east, south and west perspectives for the entire US.
- **Street-view images:** As the name implies, street views are photos taken from public streets. These images have high resolution where imagery is available, but the views and visual access to some buildings may be limited. An example street view is shown in Figure 4.

Roof dimensions. An accurate measurement of roof dimensions is key to sizing a PV system and planning the installation. The most important parameters are the length, width, azimuth and tilt of the various roof surfaces. Length and width determine how many rows and columns of modules fit in the available space. Area is calculated from length and width and used to estimate maximum array capacity. Due to the limited resolution of most free aerial imagery, including ortho and oblique images, it is often difficult to resolve the exact locations of roof valleys and ridges. It can also be challenging to resolve vent pipes and utility service penetrations versus debris, discolored shingles or roof features. Due to these limitations, roof dimensions developed from aerial imagery typically have an accuracy of approximately ± 1 foot for a surface that is parallel to the ground.

When using ortho images to determine roof dimensions, measurements must be corrected CONTINUED ON PAGE 74

Figure 4 Common aerial image perspectives include orthophotos (top left), oblique (top right) and street view (bottom). Each perspective can assist sales and design teams and lower project acquisition costs via remote site evaluation.

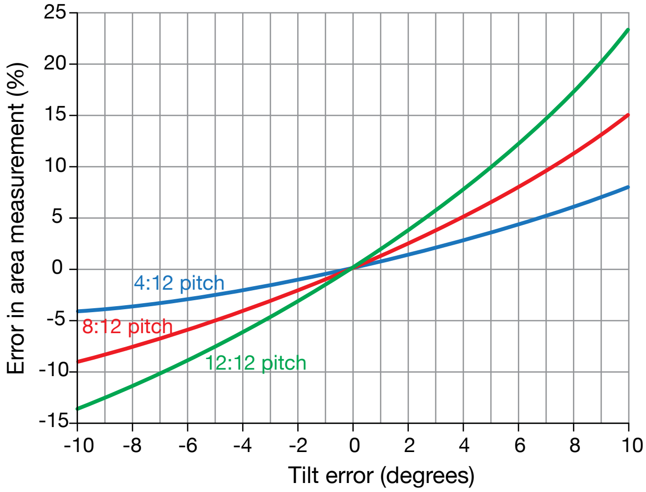
Courtesy Solmetric (4)

according to the cosine of the tilt, since the area of a tilted roof is actually larger than it appears in an image taken from directly overhead. The accuracy of the roof dimensions therefore depends on the accuracy of the tilt used in the calculation. Figure 5 shows how error in the tilt creates errors in the area measurement, depending on the roof pitch. This error can dramatically impact system design in situations that have limited roof area, such as where a row of modules just barely fits—or in reality does not fit. Measuring tilt on-site with an inclinometer is more accurate than doing so from aerial images.

To get improved accuracy from aerial imagery, the roof can be analyzed using oblique views. With the right CAD software tools, an operator can measure the roof from multiple angles and create an accurate model. Using multiple images and incorporating calculations for specific roof types enables operators to overconstrain the geometry equations and improve the accuracy of the roof model.

Annual insolation. Tilt and azimuth are factors in determining the annual insolation for a fixed array in a given location, such as Sacramento, California, as illustrated in Figure 6 (p. 76). Note that insolation does not vary significantly with small changes in tilt, so approximate tilt numbers are usually acceptable for initial energy production estimates. The azimuth, sometimes referred to as the *heading* of the roof, also factors into the insolation and can be measured using online tools such as the Solmetric Roof Azimuth Tool (see Resources) as shown in Figure 7 (p. 77). Measuring roof azimuth via aerial images can often be more accurate and reliable than on-site measurement because nearby ferrous metals in building frames or rooftops can cause interference that results in errors in the compass reading. CONTINUED ON PAGE 76

Figure 5 When using ortho images to determine roof dimensions, errors in roof tilt can dramatically impact the accuracy of the calculated roof areas. This graph illustrates the effect that inaccurate tilt measurements have on area calculation accuracy.



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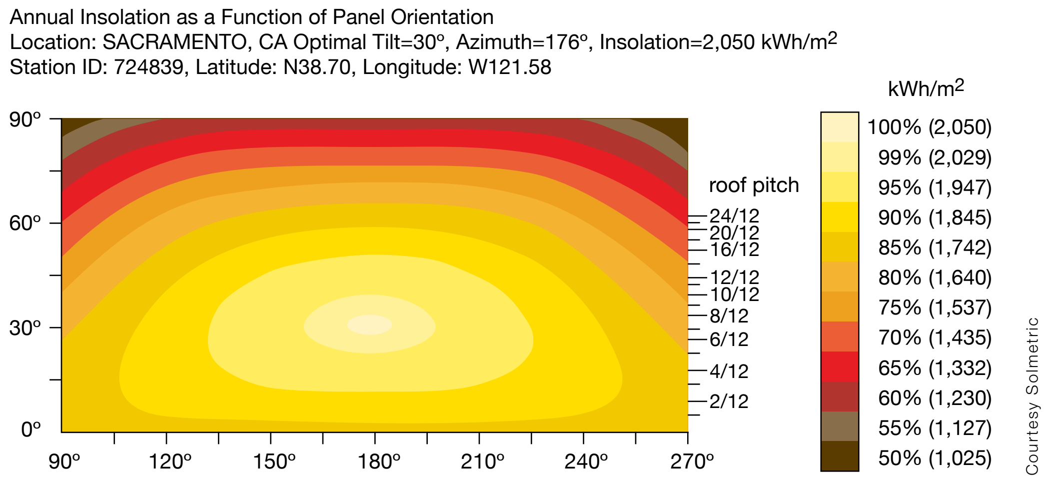
U.S. Patent #7,592,537, U.S. & Int'l Patents Pending

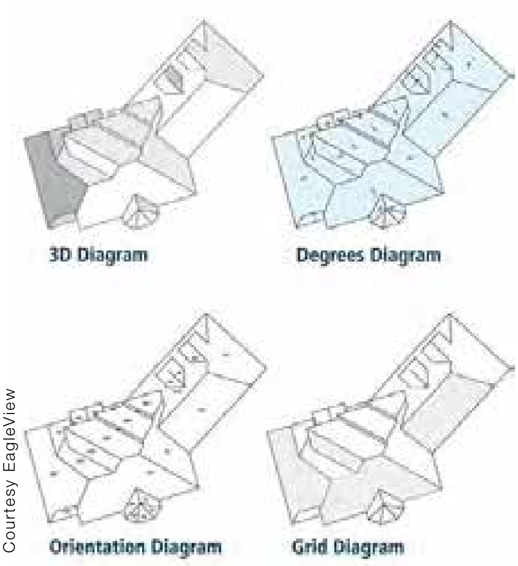
Figure 6 Tilt and azimuth are two variables used to determine annual insolation for a given site. This insolation map for Sacramento, CA, shows that insolation values do not vary significantly with small changes in tilt. While small errors in tilt measurements can have a significant impact on roof area calculations, they do not have a significant impact on energy production estimates.



Modeling approaches. CAD modeling requires a considerable investment in software tools, training and dedicated personnel. This may be a significant hurdle for many installers, who may instead opt to use a simpler tool in the presales phase (see "Online Tools for Roof Measurement and Layout," p. 72). Other installers may choose to use the services of an outside firm. Roof-modeling service providers often present analysis and reports with a 1- to 2-day turnaround and a per-building or per-site fee. Companies offering these services include Aerialogics, Bright Harvest Solar, EagleView Technologies, Pictometry and Precigeo (see Resources). Their reports include detailed roof dimensions and angles, as shown in Figure 8. Image resolution limitations make it difficult to identify gutters, vents and other small on-roof features, which remain a challenge to roof-mapping and analysis providers.

Courtesy Solmetric

Figure 7 Measuring roof azimuth via aerial images can be more accurate than on-site measurements. The latter can be affected by ferrous material in the building's roof or frame. The Solmetric Roof Azimuth Tool shown here is one option for determining roof azimuth remotely.



Courtesy EagleView

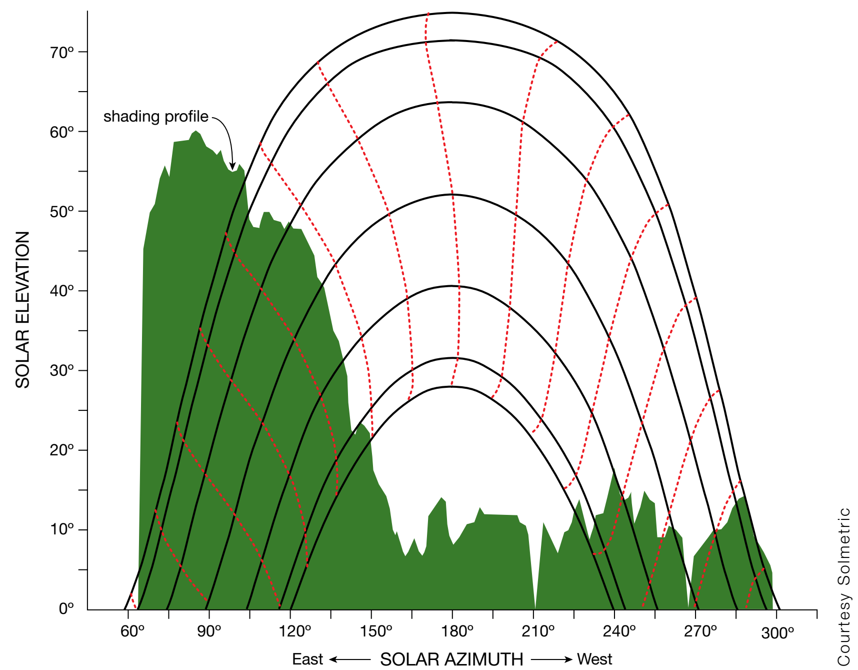
Figure 8 Roof modeling services provide cost-effective reports that contain an array of site specific information such as roof dimensions, azimuth and tilt values, 3D shadow maps and array layout diagrams.

In some cases, professional roofing reports include solar insolation analysis across the roof surface. Shade estimates and insolation charts prepared in this way often do a good job of characterizing the effects of adjacent roof surfaces or dormers, provided the modeling is done correctly. Some roof-modeling services attempt to model shade from nearby trees or buildings, although this has proved difficult in practice. Due to limited image resolution and the inability to over-constrain the CAD problem for a tree model, accuracy is poor for trees and other off-roof obstructions such as utility poles. In addition, images may be out of date and may not account for recent developments such as new construction and tree growth. Seasonal variations, such as those presented by deciduous trees, are difficult to model accurately with the available images because tree branches cannot be adequately resolved.

Sun Paths and Shade Impacts

The sun's azimuth and elevation angle relative to the horizon vary with the time of day and year. Obstructions that overlap with the sun's path cause shade during the time and month when that overlap occurs. Shading has a disproportionate impact on PV production, reducing a system's output power up to 30 times more than the relative size of the shadow on the array, according to Chris Deline, an engineer at the National Renewable Energy Laboratory (NREL). The lopsided nature of this dependency comes from the fact that cells are connected in series and that shading a substantial portion of just one cell is enough to trigger the associated bypass diode, temporarily eliminating the production of that module substring.

Optimizing string configurations relative to shading objects can mitigate their effects to some degree. Microinverters and dc power optimizers provide MPPT at the module level, which helps reduce shade impacts. However, a shaded module, regardless of whether it has per-module MPPT, produces less energy and therefore is a less valuable asset. Ryan Mazelli, senior solar advisor for One Block Off the Grid, a collective system purchasing provider, comments: "Requirements for shade measurements should not change if systems utilize microinverters, power optimizers or ac modules. What these products achieve is slightly better performance in partial shade conditions. Shade is shade, and a panel in complete shade is not going to produce any power." Installers and investors should not underestimate the importance of accurate shade measurements and mitigation approaches, regardless of the technology employed. ●



Shading profile Accurate shade measurements capture the sun's elevation angle and azimuth throughout the year and enable system designers to optimize array layout regardless of the power conversion technology used.

ON-SITE MEASUREMENTS AND EVALUATIONS

Although analysis using aerial imagery is increasingly useful in the early sales process, site visits provide critical information for solar installation companies. Being on-site enables sales representatives, auditors and designers to capture accurate dimensions and spot obstructions that may not have been apparent from aerial photos. Vent pipes, for example, are difficult to resolve in most aerial images and can significantly impact where modules can be placed.

Once on-site, you can verify roof dimensions and the location of obstructions such as skylights and vent pipes by using a tape measure, wheel or laser range finder. Tilt angles can be verified with an inclinometer with accuracies within 1 to 2 degrees. On rough roof surfaces, such as architectural shingles, tilt measurement accuracy can be improved by extending the footprint of the inclinometer: Place it on a length of wood or measure tilt on a rafter extending under the eave.

Shade measurements are always more accurate when made on-site using a tool such as the Solar Pathfinder or the Solmetric SunEye. These tools take into account everything within the array's field of view that can cause a shadow, from distant mountains to nearby trees to utility wires. They see what the array sees and correctly capture the current size of trees and other obstructions. They also enable the user to make measurements at the locations where the modules will be installed, such as 6 inches off the roof for a flush-mount system. (For a comprehensive review of CONTINUED ON PAGE 82

System Performance Measurements

Currently, solar lease and PPA financial vehicles are driving the residential market in many states. For example, according to Clean Power Finance, 55% of the residential systems installed in California in 2011 were financed. This number rose to a staggering 80% for the month of December 2011. System performance guarantees are a standard component in financed systems, and increased attention is being paid to system commissioning and ongoing performance measurements as a result.

The performance verification process can be separated into two phases. Phase one includes commissioning, when performance should be verified and documented to establish an initial benchmark for the system. Phase two covers the ongoing monitoring of the system over its lifetime, which is typically performed remotely. When systems are leased or financed, this phase is important to ensure that customer expectations and performance guarantees are met. "We can verify systems on-site through voltage, irradiance and temperature measurements," states Sungevity's Williford. "Through remote monitoring, we have diagnostic tools that allow us to determine if a system is performing as expected."

At the time of PV system installation, all stakeholders benefit from a comprehensive and well-documented system commissioning and performance verification procedure. (See "PV System Commissioning," October/November 2009, *SolarPro* magazine.) While commissioning residential systems is a straightforward process compared to commissioning commercial or utility-scale projects, its importance should not be undervalued. Proper commissioning is an essential aspect of limiting risk over the life of systems of any scale.

Jerry Shafer, CEO of Affinity Energy, confirms the importance of performance verification at the time of system commissioning. "We develop an as-built data sheet for the system to use as a starting point for the module and/or inverter output performance," he says. "It is a type of insurance policy for us and the investor to see the actual data. In the event of an output question, whether it is the result of dirt, shade, inverter operation or anything else that can affect performance, we know what we started with."

Industry best practices are evolving rapidly in the area of system commissioning and performance verification. Standard commissioning includes verifying system workmanship, operation, performance and acceptance documentation. Electrical testing including string open-circuit voltage, operating current and insulation resistance should be performed. Once the system is on line, system performance should be verified. A typical procedure for residential performance verification is to measure the module backsheet temperature and plane of array (POA) irradiance and simultaneously record the inverter power reading. Then a model is used to predict instantaneous power based on the irradiance, temperature, number of modules and other variables of the system. This number is compared to the inverter power that was recorded at the time of measurement. The ratio of actual power to expected power is often called the *power performance index.*

For systems using string or central inverters, more complete performance verification is possible through measurement of string I-V curves and comparisons with modeled performance (see "Field Applications for I-V Curve Tracers," August/September 2011, *SolarPro* magazine.) This approach is common for commercial and larger residential applications. An I-V curve tracer measures and quantifies how a string is performing compared with how it *should* be performing under current irradiance and temperature conditions. Confidence that a new system is performing optimally on day one is important to system owners, whether they are homeowners or finance providers.

"Accountability is a significant issue for this industry. By offering a performance guarantee for all our systems, we create our own accountability. I believe that this will become the standard within the industry."

—Mateo Williford, Sungevity

Beyond initial performance verification at the time of commissioning, ongoing performance monitoring is becoming more important industrywide, especially when residential leases and performance guarantees are in play. "Performance guarantees are becoming the norm, but they create a problem. In the past, a program would verify the performance expectation only one time after construction," states Kevin Wright, managing director of United Management and Consulting. "Under the new model with a PPA, performance is constantly evaluated," he adds. "In the end, this means system design and accurate site analysis are much more critical. Installation companies are married to the project for life." Clean Power Finance's Myers echoes Wright's comments: "Project underwriters are the new driver of best practices for financed systems and are accountable for maintaining prolonged system performance for the lifetime of the contract." ●

on-site shade measurements, see "Solar Site Evaluation," December/January 2009, *SolarPro* magazine.)

Leasing and PPA contracts typically guarantee a minimum level of performance. The contract may stipulate that the building owner is responsible for controlling shading. If a system begins to underperform after several years of operation, shading may be suspected. New on-site measurements may be required for comparison with the original measurements made when the system was installed. Accurate and repeatable solar access measurements can identify tree growth that may cause performance reductions.

To allow repetition of an on-site shade measurement years later, most likely by a different operator, it is critical to identify the precise physical location on the roof where each measurement was taken, since the solar access is different at different locations. Limitations of instrumentation accuracy and on-site measurement accuracy can both contribute to uncertainty in shade measurements. Dedicated shade measurement tools like the Solmetric SunEye are factory calibrated for precise operation of the camera and lens, as well as the compass and tilt sensors. The angle accuracy after calibration is typically less than 1° azimuth and 1° elevation. To facilitate accurate positioning of the shade profile skylines, the Solmetric SunEye measurement locations can be pinpointed on an aerial ortho image with the recent addition of a skyline-mapping feature, as illustrated in Figure 9. These measurements can be stored securely online and then used as a reference for future shade measurement comparisons.

Figure 9 On-site shade measurements may need to be repeated at some point if a system is underperforming and shading from new vegetation growth is suspected. Solmetric's skyline mapping tool (shown here) allows the user to drag icons representing skyline locations to the exact location where they were taken and store the measurements and locations online. This allows the measurements to be repeated and compared to original measurements at a future date.

Other Trends to Watch

In addition to the tools and techniques I have discussed, other trends and developments are having an impact on the industry and will continue to do so in the coming years. Tablet computers and smartphones are becoming more capable and affordable, allowing users to automate and simplify many tasks on-site, including data gathering, proposals, audits, inspections and other functions. Data collected on-site, including shade measurements and performance verification data, will increasingly be securely stored online in the cloud, allowing streamlined access by the appropriate stakeholders. The solar industry will likely continue to benefit from business models and tools that have been developed in the more time-tested construction market.

Due in part to the increased availability and sophistication of financing options, the residential solar market is expanding rapidly. With this expansion comes more focus on system performance and on costs at every point in the system life cycle. Powerful web-based tools are enabling remote preliminary evaluations of solar sites and, coupled with accurate on-site measurement tools, are giving installers the ability to find the right balance between cost, time, risk and ROI. Whether on-site, online or both, measurement tools and techniques are evolving at a rapid pace to help meet the needs of a dynamic industry.

CONTACT

Peter Hoberg / Solmetric / Sebastopol, CA / solmetric.com / peter@solmetric.com

Resources

Aerialogics / 877.623.7425 / aerialogics.com
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Solar Energy International
April 23 – April 7
Grass Valley
solarenergy.org

GT500MVX-System Operation & Maintenance
Schneider Electric
May 8 – May10
Livermore
schneider-electric.com

XW & Conext Training
Schneider Electric
May 16 – May 18
Livermore
schneider-electric.com

Solar PV Associate
Everblue Training Institute
May 28 – June1
Berkeley
everblue.edu

Colorado

Grid-Direct PV Lab Week
Solar Energy International
April 30 – May 4
Paonia
solarenergy.org

Grid-Direct PV Design & Installation
Solar Energy International
May 7 – May 11
Boulder
solarenergy.org

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Solar Energy International
May 7 – May 11
Paonia
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Residential PV Inverter Training
Solectria Renewables
May 13 – May 17
Denver
solren.com

Solar Hot Water Design & Installation
Solar Energy International
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Florida

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April 16 – April 20
Fort Lauderdale
ussolarinstitute.com

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Florida Solar Energy Center
May 30 – June 1
Cocoa
fsec.ucf.edu

Georgia

Advanced Solar Installer Training
ONtility & Suneva
April 9 – April 13
Atlanta
ontility.com

Hawaii

Advanced Grid-Direct PV System Design & the *NEC*
Solar Energy International
April 2 – April 6
Honolulu
solarenergy.org

Maryland

Solar Thermal Installer Certification Prep
IEC Chesapeake
April 9 – May 5
Jessup
iecchesapeake.com

Advanced PV Systems Design & Installation
IEC Chesapeake
April 24 – June 26
Odenton
iecchesapeake.com

Massachusetts

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Solar Energy International
May 7 – May 11
Boston
solarenergy.org

Nebraska

Off-Grid Power Systems for Remote Locations
Buckville Energy Consulting
May 9 – May 10
Chadron
store.otherpower.com

New Jersey

Solar PV Conductor Sizing
Krannich Solar
April 3
Mount Laurel
krannich-solar.com

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sma-america.com

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Tupper Lake
heatspring.com

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New York
ontility.com

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Suffern
sunyrockland.edu

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April 24 – April 26
Kingston
sunyulster.edu

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Solar Thermal Technology
Ulster BOCES
May 3 – June 5
Port Ewen
ulsterboces.org

Conquering the Forms & Regulations of Solar Incentives
SUNY Ulster
May 4
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sunyulster.edu

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Rockland Community College
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sunyrockland.edu

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Training

Pennsylvania

PV Design & Installation
Electric Education Center
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Infinite Solar
April 16 – April 20
May 14 – May18
Philadelphia
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April 14 – April 15
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Solar Air Heat Introduction
Midwest Renewable Energy Association
April 20
Custer
midwestrenew.org

Advanced Solar Space Heating Installation
Midwest Renewable Energy Association
April 21 – April 22
Custer
midwestrenew.org

Solar Domestic Hot Water
Midwest Renewable Energy Association
April 27
Custer
midwestrenew.org

Solar Hot Water Installation Lab
Midwest Renewable Energy Association
April 28 – April 30
Custer
midwestrenew.org

Canada

GT500MVX-System Operation & Maintenance
Schneider Electric
April 10 – April 12
Toronto
schneider-electric.com

XW & Conext Training
Schneider Electric
April 24 – April 26
Toronto
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Online

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Projects

System Profiles

groSOLAR
Vermont Air National Guard

Overview

DESIGNER: Brian Browning, electrical engineer; Tim Macke, solar engineer; groSolar, grosolar.com

INSTALLATION TEAM: Harold Craig, site superintendent; Frank Griffin, project executive; Matt DiNisco, commercial project manager; Rod Viens, procurement manager; groSolar

DATE COMMISSIONED: September 2011

INSTALLATION TIME FRAME: 120 days

LOCATION: Burlington, VT, 44.5°N

SOLAR RESOURCE: 4.3 kWh/m²/day

HIGH/LOW DESIGN TEMPERATURES: Per Solar ABCs Solar Reference Map: 88°F/-15°F

ARRAY CAPACITY: 1.446 MW (1,388.7 kW fixed-tilt ground mount, 25.2 kW dual-axis tracked ground mount, 31.9 kW roof mount)

ANNUAL AC PRODUCTION: 1,827 MWh

Equipment Specifications

MODULES: 5,798 Kyocera KD245GX-LPB, 245 W STC, +5/-3%, 8.23 Imp, 29.8 Vmp, 8.91 Isc, 36.9 Voc; 120 Evergreen ES-A-210-fa3, 210 W STC, +4.99/-0 W, 11.48 Imp, 18.3 Vmp, 12.11 Isc, 22.8 Voc

Fixed-Tilt Ground Mount

INVERTERS: Inverter A: One Satcon PVS-250, 250 kW, 600 Vdc maximum input, 320–600 Vdc operating range, 3-phase 480Y/277 Vac output; Inverters B and C: Two Satcon PVS-500, 500 kW, 600 Vdc maximum input, 320–600 Vdc operating range, 3-phase 480Y/277 Vac output

ARRAY: 13 Kyocera KD245GX-LPB modules per source circuit (3,185 W,

Courtesy groSolar (4)

The federally funded Multiple Award Task Order Contract (MATOC) Renewable Energy Project at the Vermont Air National Guard Base in Burlington utilizes three PV-mounting methods: a fixed-tilt ground mount (the largest of the three), a dual-axis tracked array and a flush-mounted rooftop array. All system components were purchased under Buy American guidelines.

The project is being deployed in three distinct phases. Phase 1 included all three arrays. Phase 2 added capacity to the fixed, ground-mounted array. Phase 3, which will further expand the ground-mounted array, was incorporated into the overall project design and will be awarded and installed at a later date. The Phase 3 interconnection switchgear, transmission lines, inverter pad and conduit, and data acquisition systems were included in the first two phases.

The site for the fixed, ground-mounted array was formerly used for aircraft storage. Prior to the PV system installation, the entire area was graded, leveled and covered in gravel or topsoil by Engineers Construction, the project contractor. After completing soil testing and determining pile depth, groSolar installed Schletter racking posts, binders and purlins. All racking components were carefully leveled to provide a consistent structure for the array.

The Base's utility provider, Green Mountain Power (GMP), performed a feasibility study to assess how all three phases of the fixed ground-mount array would affect the utility's existing infrastructure. To accommodate the system's location and generation capacity, GMP installed new transmission lines and a new transformer.

The roof-mounted array, located on the Base's Building 90, was installed on a standing-seam metal roof. DeWolfe Engineering reviewed the building's structure, assessed the additional load imposed by the PV system and provided specifications for attachment points based on calculated uplift forces. The

8.23 Imp, 387.4 Vmp, 8.91 Isc, 479.7 Voc); 11 source circuits per combiner, typical (35 kW, 90.53 Imp, 387.5 Vmp, 98.01 Isc, 479.7 Voc); Inverter A: 88 source circuits total (280.3 kW, 724.24 Imp, 387.4 Vmp, 784.08 Isc, 479.7 Voc); Inverter B: 176 source circuits total (560.6 kW, 1,448.48 Imp, 387.4 Vmp, 1,568.16 Isc, 479.7 Voc); Inverter C: 172 source circuits total (547.8 kW, 1,415.56 Imp, 387.4 Vmp, 1,532.52 Isc, 479.7 Voc); array total 1,388.7 kW

ARRAY INSTALLATION: Fixed ground mount, Schletter FS System Generation 6 racking, 170° azimuth, 30° tilt

ARRAY STRING COMBINERS: 40 Cooper Bussmann BCBS Series Standard Combiner Boxes, 15 A fuses

Tracked Ground Mount

INVERTERS: Six SMA Sunny Boy 6000-US, 6 kW, 600 Vdc maximum input, 250–480 Vdc MPPT range, single-phase/277 Vac output

ARRAY: 20 Evergreen ES-A-210-fa3 modules per source circuit (4,200 W, 11.48 Imp, 366 Vmp, 12.11 Isc, 456 Voc), one circuit per inverter; array total: 25.2 kW

TRACKERS: Six AllSun Tracker Series 20; packaged system includes modules, tracker and inverter

ARRAY INSTALLATION: Dual-axis tracked ground mount

Roof Mount

INVERTER: One Satcon PVS-30, 30 kW, 600 Vdc maximum input, 305–600 Vdc operating range, 3-phase/208 Vac output

ARRAY: 13 Kyocera KD245GX-LPB modules per source circuit (3,185 W, 8.23 Imp, 387.4 Vmp, 8.91 Isc, 479.7 Voc), 10 source circuits total (31.9 kW, 82.3 Imp, 387.4 Vmp, 89.1 Isc, 479.7 Voc)

ARRAY INSTALLATION: Roof mount, standing-seam metal roofing, S5! Mini Clamps, Unirac SOLARMOUNT racking, 131° azimuth, 16° tilt

ARRAY STRING COMBINER: Cooper Bussmann BCBS Series Standard Combiner Box, 15 A fuses

SYSTEM MONITORING: ArgusON SPM-150 system performance and environmental monitoring, Shark revenue-grade energy meter, Control Technologies building performance monitoring

system was interconnected at the building's utility service after a feasibility study determined that the existing utility infrastructure would support the PV system's output.

The dual-axis tracking system consists of six AllSun trackers that utilize GPS array positioning. These six subarray outputs are combined at a dedicated subpanel that is incorporated into the fixed ground-mount array switchgear, transformer and transmission lines. The tracker interconnection was originally designed to combine with the roof-mounted system. However, the GMP feasibility study determined that the present infrastructure could not support the additional power that the tracked array would introduce. Therefore, this system was redesigned to combine with the fixed ground-mount array switchgear.

> "Every detail of this project was mapped out to specific requirements, from site work to conduit runs to the landscaping. Our nimbleness and ability to install the three types of applications in a single project, while maintaining high standards, resulted in a nice-looking project that will save the Vermont Air National Guard millions of dollars over the next several decades."
> *—Jeffery Wolfe, CEO and cofounder, groSolar*


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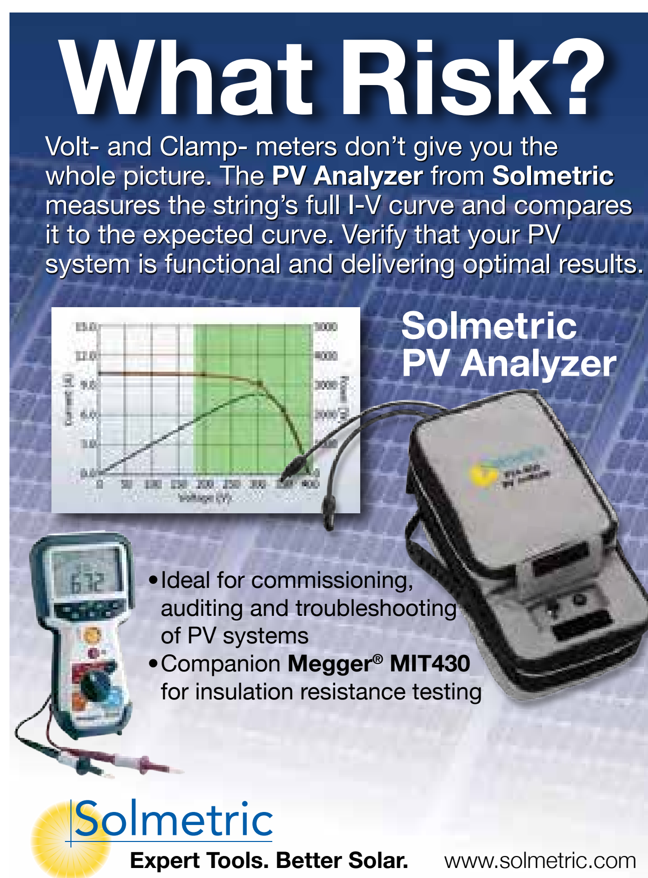
What Risk?
Volt- and Clamp- meters don't give you the whole picture. The PV Analyzer from Solmetric measures the string's full I-V curve and compares it to the expected curve. Verify that your PV system is functional and delivering optimal results.
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RMK SOLAR

Snyder's of Hanover

Courtesy RMK Solar (4)

Overview

DESIGNER: Robert H. Kline, president, RMK Solar, rmksolar.com

LEAD ENGINEER: Jason Dorta, solar design engineer, RMK Solar

DATE COMMISSIONED: May 2011

INSTALLATION TIME FRAME: 160 days

LOCATION: Hanover, PA, 39°N

SOLAR RESOURCE: 4.2 kWh/m²/day

HIGH/LOW DESIGN TEMPERATURES: per Solar ABCs Solar Reference Map: 91°F/5°F

ARRAY CAPACITY: 3.546 MW

ANNUAL AC PRODUCTION: 4,453 MWh

Snyder's-Lance, a snack food manufacturer with plants across the US and in Ontario, Canada, recently commissioned a 3.546 MW PV array located at its Hanover, Pennsylvania, facility. RMK Solar was contracted to complete the design and construction of the project, which features a 3 MW array interconnected with the company's manufacturing facility service and a 546 kW array interconnected with a recently completed R&D facility. The total energy generated on-site offsets approximately 30% of the campus's annual consumption.

RMK's initial design called for one array that would be interconnected with the manufacturing facility's existing service. However, as RMK worked with local utility First Energy to establish the interconnection agreement, it discovered that the largest PV array that could be connected to a single service was 3 MW. This limitation required design changes to accommodate both the utility's and the customer's requirements.

SMA Sunny Central HE inverters and medium-voltage transformers were specified to allow direct connection to the plant's 13.2 kVac service. The transformers were located close to the inverters to reduce the required conductor size by increasing the transmission voltage. The switchgear used for the utility interconnection was custom designed by Square D.

Given the large area required for the array and the slope variations on the site, RMK could not perform the excavation needed to create a relatively flat field for mounting the array. As a result, driving the racking system's piles required meticulous attention to position the array to precisely follow the contours of the land.

Upon completing the test pile installation and soil testing, RMK found that the hilly terrain had high amounts of shale. Initially, this suggested that a large number of piles would not reach their required depth. Custom trailers were developed and equipped with punching, drilling and cutting tools to modify the affected piles. Fortunately, only several dozen piles out of 2,700 required modification, and the addition of concrete footers was avoided.

Another challenge was the need to bore under a state highway. The PV array is located on the opposite side of the highway from the interconnection point. The bore hole had to be carefully placed because the required path was close to existing township water mains and other utilities. A directional bore was successfully located without incident.

RMK designed and installed a custom monitoring system that employs RS-485 and Modbus communication between the inverters and the Shark 100S revenue meters. Current transducers were installed to monitor each individual source-circuit combiner box. All monitoring devices were routed back to a main PLC using fiber optics. The customized solution allows RMK Solar to have web access to all live and historical data and also permits a remote on/off control of the entire system's main switchgear.

"The Snyder's of Hanover solar project faced many up-front challenges due to the size of the system. Our engineering team worked closely with the utility company to design a single system that would feed two services and meet all utility requirements."

—Jason Dorta, RMK Solar

Equipment Specifications

MODULES: 15,092 SCHOTT PERFORM POLY 235, 235 W STC, +4.99/-0 W, 7.78 Imp, 30.2 Vmp, 8.42 Isc, 37.1 Voc

INVERTERS: 3-phase, 13.2 kVac service, seven SMA Sunny Central 500HE-US, 500 kW, 600 Vdc maximum input voltage, 330–600 Vdc MPPT range; four copper 200 V:13.2 kV 1,000 kVA transformers total; two inverters per transformer (typical)

SUBARRAYS: 14 modules per source circuit (3,290 W, 7.78 Imp, 422.8 Vmp, 8.42 Isc, 519.4 Voc); 22 strings per source-circuit combiner (72.4 kW, 171.2 Imp, 422.8 Vmp, 185.2 Isc, 519.4 Voc); seven combiner circuits per inverter (506.7 kW, 1,198 Imp, 422.8 Vmp, 1,296 Isc, 519.4 Voc); seven subarrays total

ARRAY INSTALLATION: Ground mount, Schletter FS System racking, 180° azimuth, 39° tilt

ARRAY STRING COMBINERS: 49 Cooper Crouse-Hinds, CCBS22F20, 15 A fuses

SYSTEM MONITORING: Custom-designed PLC-based monitoring system

Advertiser *Index*