October/November 2010

PV Monitoring Granularity | Surge Protection

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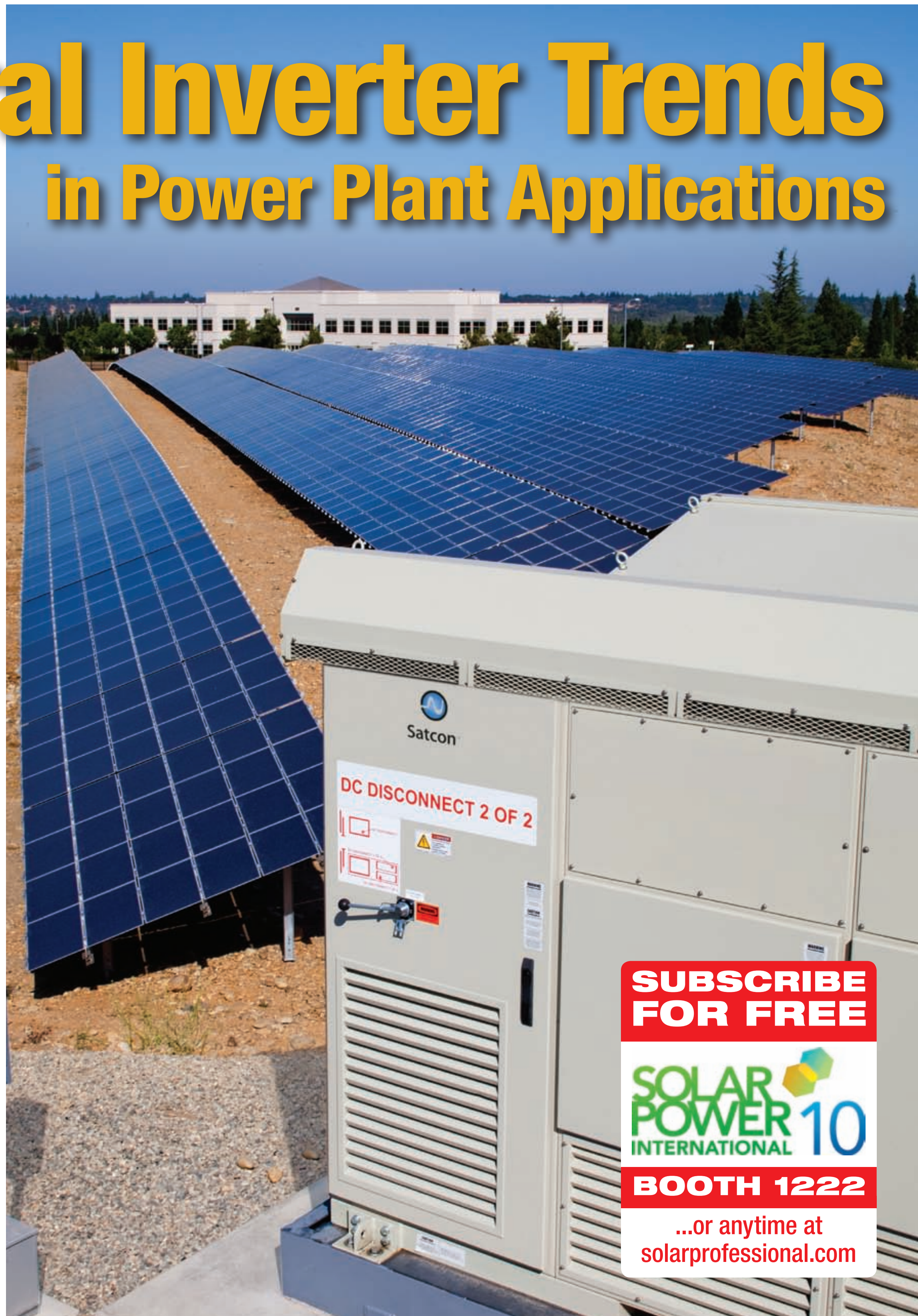


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# Contents

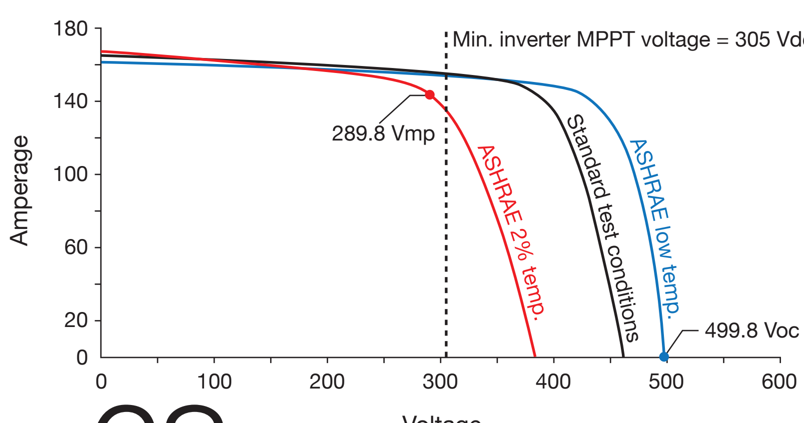
October/November 2010 Issue 3.6

## Features




82






68


NEED TRAINING?

# Contents²

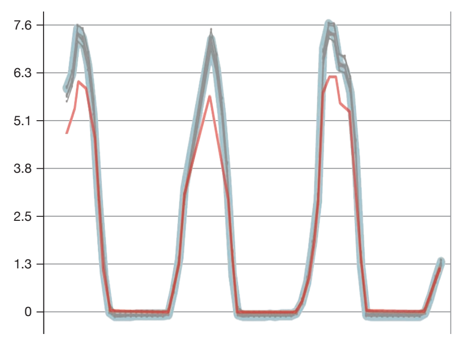
October/November 2010 Issue 3.6

## Departments

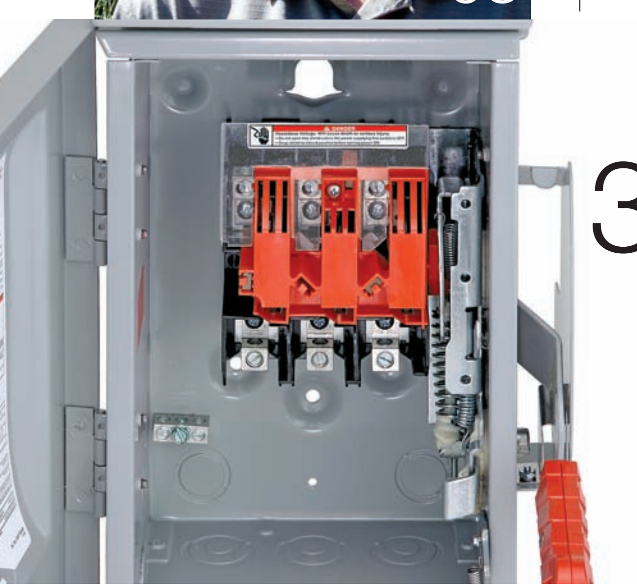
### FRONT END








16



30

### BACK END



**ON THE COVER** **SolarCity's commercial project manager, Jonathan Gornik, coordinated this 1.1 MW STC PV power plant at Intel's Folsom Campus in Folsom, California. Power generated by the First Solar thin-film array is exported to the utility grid at 12.47 kV using a custom integrated Satcon Prism 1 MW Medium Voltage Package, which includes two PowerGate Plus 500 kW inverters, one 1,000 kVA oil-filled transformer and medium-voltage switchgear.**

Photo Courtesy of Satcon Technology

# Contributors

## Experience + Expertise

**Greg Ball** is a senior electrical engineer at BEW Engineering in San Ramon, California. He has more than 20 years of experience working for solar system integrators and engineering firms. He is responsible for the electrical design of more than 120 MW of PV installations in the US, Europe and Asia. He serves as co-convener for the IEC's PV Balance of System Working Group and is active in US codes and standards development.

**Bill Brooks** is a registered professional engineer in both North Carolina and California. A consultant to the PV industry on a variety of topics—including performance, troubleshooting and training—since 1992 he has focused on the analysis and testing of PV systems for utility-interconnected applications. He has written widely used technical manuals for the PV industry. His experience includes work on the technical review committees for the *NEC* and the Institute of Electrical and Electronic Engineers (IEEE) for utility interconnection standards.

**Cosmos Corbin** is a co-founder of DECK Monitoring, a renewable energy monitoring company based in Eugene, Oregon. He leads the product development team, designing new features and refining existing solutions. His previous positions focused on commercial PV system design. Cosmos continues to draw on his experience in the commercial and utility-scale PV industry to develop monitoring solutions for solar integrators and their customers.

**Darlene McCalmont** is a co-founder and COO of McCalmont Engineering in Los Altos, California, a firm specializing in PV system design. Previously she co-founded REgrid Power, a solar integrator in San Jose, California, and served as VP of operations. She has more than 30 years of experience managing operations processes through efficiency measures and cost reduction. Darlene holds an MBA from the University of Houston and a BS in chemical engineering from Ohio State University. She is a NABCEP Certified Solar PV Installer.

**Rob Schlesinger** is an electrical engineer with professional engineer registrations in multiple states. He has more than 25 years of experience related to the electric utility and power industry. He has been associated with DEHN for nearly 10 years, creating solutions for electrical transients—primarily due to lightning and switching surges—on power, control and instrumentation systems used in the PV and wind generation industries. Rob holds an MBA in marketing and finance.

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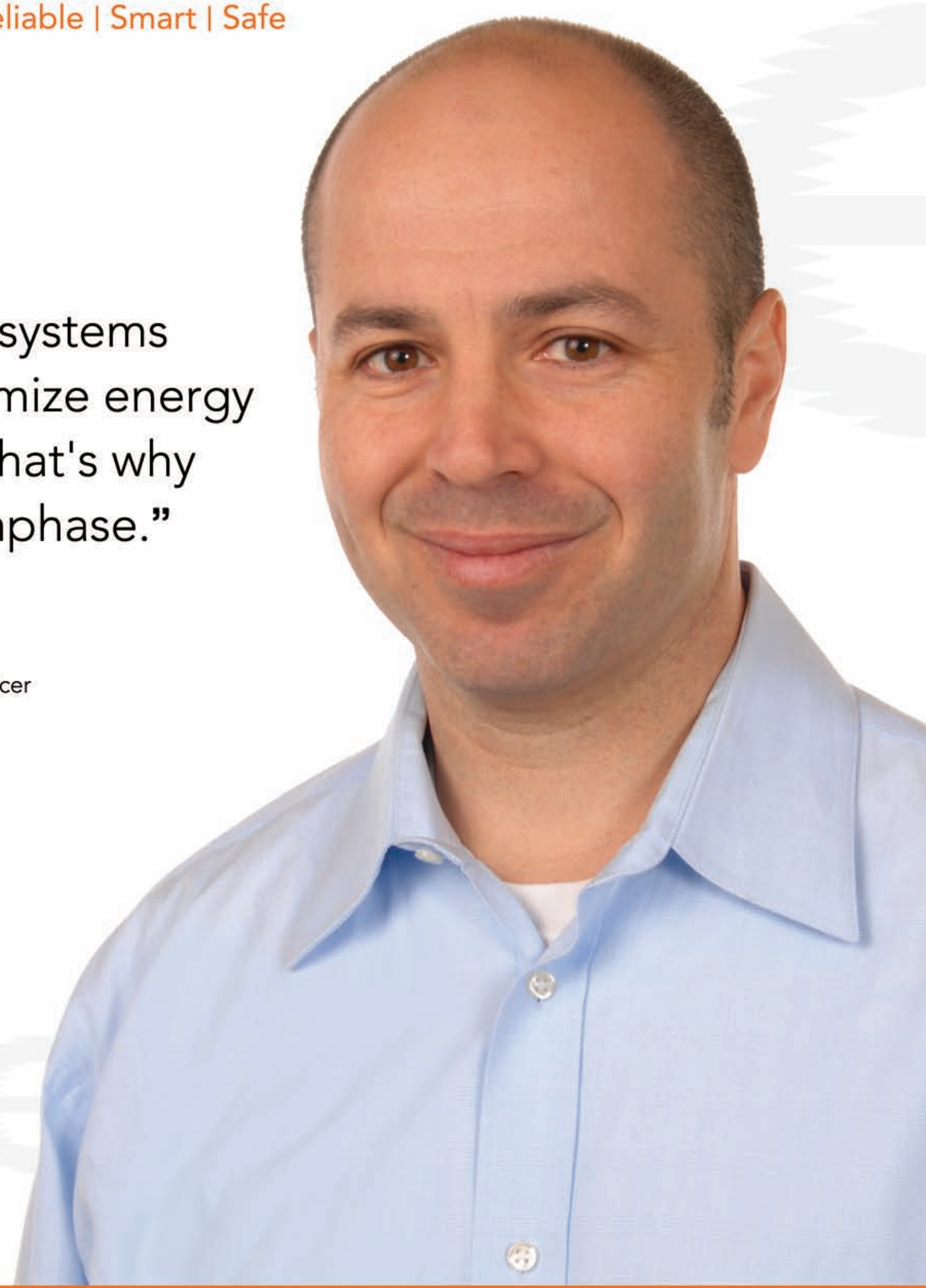

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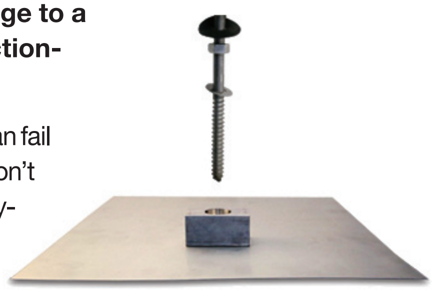

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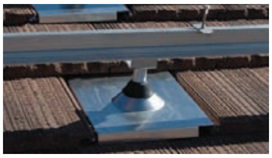

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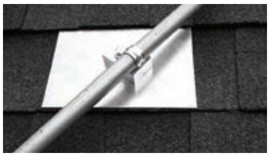

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# Adding Granularity to PV Monitoring

As a provider of energy monitoring solutions, DECK Monitoring works daily with developers and investors for commercial and utility-scale PV systems. On larger projects, stakeholders typically want varying degrees of visibility into system performance beyond cumulative energy generation. Based on past experience or contract terms, project partners often know exactly what monitoring package is required and specify the level of monitoring granularity they need to achieve project goals. Nonetheless, I often find myself fielding questions such as: What level of monitoring is appropriate for my project? Why monitor at the string or subarray level? Does it make economic sense to add this degree of monitoring granularity? Here I break down the answers to these and other questions that may come up when deciding what type of monitoring solution to specify.

Let us assume that using a revenue-grade meter to monitor overall PV system generation is a given. Most incentive programs require the use of a revenue-grade third-party meter to measure the system's total production. In commercial or utility-scale projects, this is usually the foundation upon which other monitoring components are added. Granular monitoring of solar arrays is most commonly achieved using three different methods: inverter data, subarray monitoring and string-level monitoring.

**Inverter data.** The first and most common method of gathering system performance and status information is a direct data connection to the inverters. This data connection is often referred to as *inverter specific* or *inverter direct.* The inverter is typically considered to be the most common point of failure on-site. Because of the integral nature of the inverters to system production and their relatively high failure rate compared to other installed components, monitoring the inverters is usually the first additional set of data points a customer requests. Inverter data provide key information such as visibility into the performance of each inverter's array, the power lost when converting from dc to ac and valuable fault code information for remote troubleshooting. This monitoring approach is usually the least expensive since there are little or no additional hardware costs. It also provides a good deal of useful information.

**Subarray monitoring.** Although monitoring at the inverter level provides data on the performance of the system by each inverter's array, this level of monitoring is not specific enough to identify issues on the string or module level on larger systems. To monitor performance and operation on a more granular level, project developers may specify subarray or zone monitoring. This approach allows you to break apart each inverter's array into any number of smaller metered arrays and provide greater visibility than inverter monitoring alone.

For example, by isolating the performance of individual combiner boxes, you can use the monitoring system to remotely identify problem strings and areas of the array with cleaning or shading issues—without costly site visits and analysis.

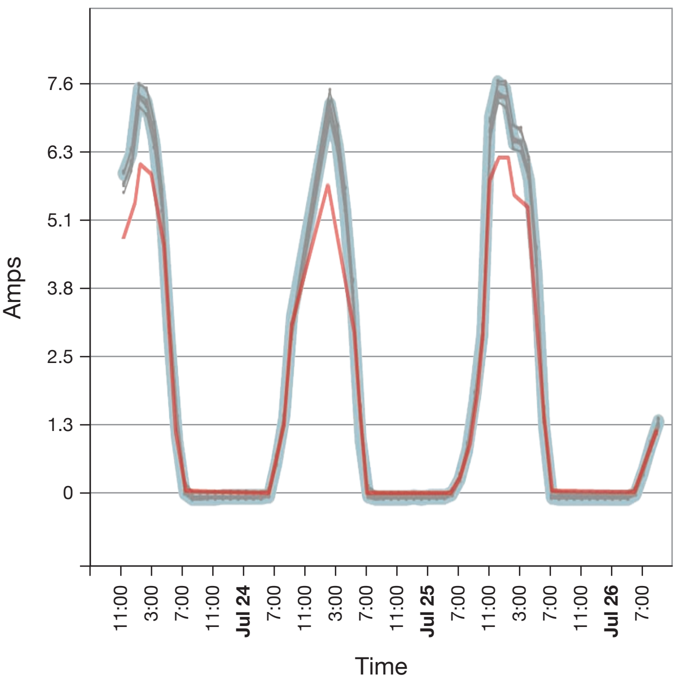
**String-level monitoring.** Some developers go one step further and monitor the system on a string level. String-level monitoring is usually achieved by specifying monitoring or smart combiner boxes that measure each string (or pair of strings) independently. This method of monitoring offers the highest degree of visibility into commercial or utility-scale projects and allows you to identify underperforming strings in which modules are down, need cleaning or maintenance, or are subject to excessive shading.

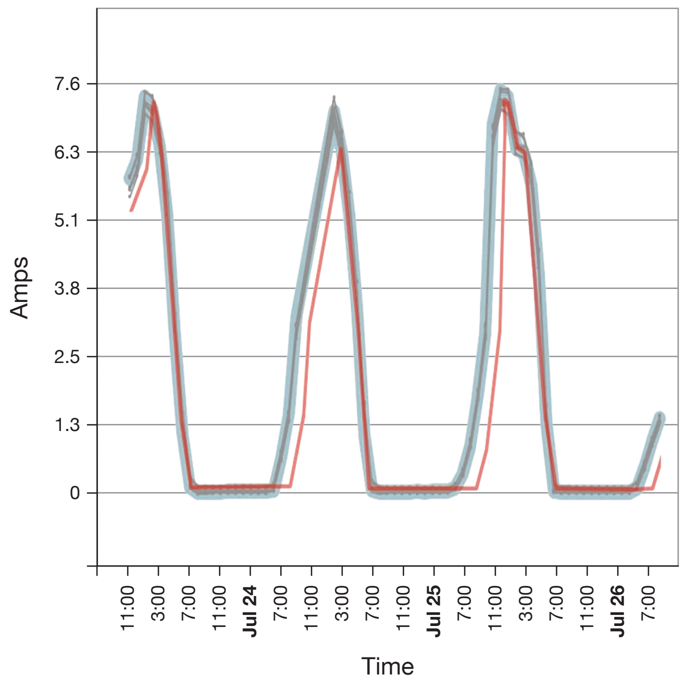
### Increasing Performance Ratios

While granular PV monitoring solutions can give you a highly detailed look into the performance of a system, the associated hardware and software come at a price. To determine the level of monitoring that is appropriate for your project, you need to understand why such solutions were developed and are in increasingly high demand.

A standard measurement for system performance is known as the *performance ratio.* The performance ratio refers to the relationship between actual yield and the target yield. Many designers expect a well-designed system to have a performance ratio of 0.77. In practice, performance ratios on installed solar farms have a wide variation. If you look at the 15 largest solar projects in the online Photovoltaic Power Systems Program database of International Energy Agency solar farms worldwide, you will see that the average performance ratio of installed systems is 0.66. To take another example, a subset of solar farms installed and maintained by the Tucson Power Company maintained a performance ratio of 0.79. There is a 13% difference in the annual performance ratio between these two sets of data.

What causes these solar farms to have such different performance ratios? Losses in performance are often due to issues on-site that require ongoing maintenance to optimize energy harvest. Historical data from these projects and others show that solar farms need unscheduled maintenance far beyond the initial installation period and that drops in the performance ratio are usually related to lack of maintenance. Solar monitoring CONTINUED ON PAGE 18




Courtesy DECK Monitoring (2)

**Figure 1** In commercial and utility-scale projects, subarray or string-level monitoring can decrease O&M costs and alert project partners to performance issues. This screen capture illustrates an underperforming string that likely would have gone unnoticed without granular monitoring.

**Figure 2** Active granular system monitoring reveals performance issues that may develop over time. This screen capture suggests that vegetation growth may be impacting the underperforming string.

solutions offer enhanced visibility and enable timely maintenance and optimization of the system's performance. Through remote monitoring, system owners can identify issues before they affect the performance ratio of the project for a substantial and costly amount of time. The Tucson Power Company, for example, found a need for unscheduled site maintenance approximately every 7 months to maintain a high performance ratio.

## Granular Monitoring Value Proposition

What is the value of optimizing a solar project's performance ratio? A large commercial solar project or solar farm can often annually generate six or even seven digits of revenue from energy sold back to the grid. Project investors and developers depend on that revenue over the life of the system to achieve the expected return on investment. Many system designers and BOS experts consider subarray or string monitoring an insurance play. The amount of revenue that a single string can produce in its lifetime is typically somewhere between $6,000 and $12,000, depending on its location, size, installation and other factors. If a string or module has an issue, it can be caught right away when subarray or string-level monitoring is employed. The problem can be repaired with minimal revenue loss. Monitoring that string via subarray or string-level monitoring to ensure that it is performing optimally should cost only a percentage point or two of the overall lifetime revenue generated by that string. On a per-system basis, the investors, developers, hosts and integrators need to determine if the potential gains from optimizing the lifetime revenue outweigh the cost of installing a granular monitoring system. This decision can take into consideration the O&M model used by the parties involved. Many developers plan on investing the capital needed to monitor the system in detail and to perform the regular maintenance needed to optimize production. Others prefer a more hands-off approach in which they accept a lower performance ratio on-site and perform maintenance only in the most urgent situations, such as a failed inverter, that dramatically affect system performance.

In the string comparisons depicted in Figure 1 and Figure 2, normally performing strings are represented as a thin gray line. In Figure 1, you can see that String 6, represented by a red line, is consistently underperforming compared to the rest of the strings in this section of the array. The data indicates that this particular string has a module that is damaged, needs to be cleaned or requires other maintenance. Figure 2 shows another important piece of information: String 6 has excessive shading issues. You can tell that it is being shaded because production consistently starts later in the day and then quickly ramps up to an equivalent level of production to the rest of the strings. This shading could be due to equipment located nearby, installation practices or even growth of vegetation over the course of a year or two. In any case, it is clear that a field technician visiting this site could improve performance and immediately improve revenue.

If this graph compared combiners or subarrays, as it would with zone monitoring, you would get the same type of information, but your visibility would extend down only to the string.

### Reducing O&M Costs

The integrator is typically responsible for system performance and therefore needs to actively monitor its performance. A granular monitoring system can greatly reduce O&M costs by remotely pinpointing problems that would otherwise go unnoticed or require costly site visits to identify. Most commercial-grade monitoring solutions include an alarm panel that allows users to create custom alarms to notify the correct personnel when there is a problem on-site. These alarms automatically send an email when triggered. Identifying a problem quickly allows your team to go directly to the problem area, with the right tools and equipment. The cost of a field inspection varies from site to site and is a function of the cost of labor, time required and installation-specific details. Based on DECK Monitoring's analysis of a recent commercial project, monitoring a 1 MW system at the subarray level is equivalent in cost to performing a single annual field inspection. (This assumes the use of licensed electricians for labor to allow for in-the-field optimization.)

Investors are primarily interested in optimizing the PV system revenue. They need to ensure that performance targets are met, and they have an interest in the timely correction of on-site issues that could impact performance. A granular monitoring solution that includes zone or string-level data provides accountability for the party responsible for maintaining performance and minimizes ongoing O&M costs. Finally, detailed real-world system performance data enables both project developers and investors to adjust their development strategies and financial models for future systems.

*—Cosmos Corbin / DECK Monitoring / Eugene, OR / deckmonitoring.com*

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# Surge Protection Devices for PV Installations

Because PV installations must be designed to provide full exposure to the sunlight, they are highly vulnerable to the effects of lightning. The capacity of a PV array is directly related to its exposed surface area, so the potential impact of lightning events increases with system size. Where lighting occurrences are frequent, unprotected PV systems can suffer repeated and significant damage to key components. This results in substantial repair and replacement costs, system downtime and the loss of revenue. Properly designed, specified and installed surge protection devices (SPDs) minimize the potential impact of lightning events when used in conjunction with engineered lightning protection systems.

A lightning protection system that incorporates basic elements such as air terminals, proper down conductors, equipotential bonding for all current-carrying components and proper grounding principles provides a canopy of protection against direct strikes. If there is any concern of lightning risk at your PV site, I highly recommend hiring a professional electrical engineer with expertise in this field to provide a risk assessment study and a protection system design if necessary.

It is important to understand the difference between lightning protection systems and SPDs. A lightning protection system's purpose is to channel a direct lightning strike through substantial current-carrying conductors to earth, thus saving structures and equipment from being in the path of that discharge or being directly struck. SPDs are applied to electrical systems to provide a discharge path to earth to save those systems' components from being exposed to the high-voltage transients caused by the direct or indirect effects of lightning or power system anomalies. Even with an external lightning protection system in place, without SPDs, the effects of lightning can still cause major damage to components.

For the purposes of this article, I assume that some form of lightning protection is in place and examine the types, function and benefits of the additional use of appropriate SPDs. In conjunction with a properly engineered lightning protection system, the use of SPDs at key system locations protects major components such as inverters, modules, equipment in combiner boxes, and measurement, control and communications systems.

## The Importance of SPDs

Aside from the consequences of direct lightning strikes to the arrays, interconnecting power cabling is very susceptible to electromagnetically induced transients. Transients directly or indirectly caused by lightning, as well as transients generated by utility-switching functions, expose electrical and electronic equipment to very high overvoltages of very short duration (tens to hundreds of microseconds). Exposure to these transient voltages may cause a catastrophic component failure that may be noticeable by mechanical damage and carbon tracking or be unnoticeable but still cause an equipment or system failure.

Long-term exposure to lower-magnitude transients deteriorates dielectric and insulation material in PV system equipment until there is a final breakdown. In addition, voltage transients may appear on measurement, control and communication circuits. These transients may appear to be erroneous signals or information, causing equipment to malfunction or shut down. The strategic placement of SPDs mitigates these issues because they function as shorting or clamping devices.

## Technical Characteristics of SPDs

The most common SPD technology used in PV applications is the metal oxide varistor (MOV), which functions as a voltage-clamping CONTINUED ON PAGE 24

### Surge Protection Device Technologies

| | Type | Impulse-current capability | Through voltage | Temporary overvoltage–withstand capability | Follow current | Power dissipation |
|---|---|---|---|---|---|---|
| Voltage switching | spark gaps | ~10–50 kA (10/350 µs) | high[1] | high | yes[1] | low |
| | gas discharge tubes | < 5 kA (10/350 µs) | high | high | yes | low |
| Voltage limiting | metal oxide varistor | some 10 kA (8/20 µs) | medium | low | no | high |
| | silicon avalanche diode | some 100 A (8/20 µs) | low | low | no | high |

[1] Can be limited

Courtesy DEHN

**Table 1** Various SPD technologies are used, often in coordination with one another, to protect PV assets from surge events.

device. Other SPD technologies include the silicon avalanche diode, controlled spark gaps and gas discharge tubes. The latter two are switching devices that appear as short circuits or crowbars. Each technology has its own characteristics, making it more or less suitable for a specific application. Combinations of these devices can also be coordinated to provide more optimal characteristics than they offer individually. Table 1 (p. 22) lists the major SPD types used in PV systems and details their general operating characteristics.

An SPD must be able to change states quickly enough for the brief time a transient is present and to discharge the magnitude of the transient current without failing. The device must also minimize the voltage drop across the SPD circuit to protect the equipment it is connected to. Finally, SPD function should not interfere with the normal function of that circuit.

SPD operating characteristics are defined by several parameters that whoever is making the selection for the SPDs must understand. This subject requires more details than can be covered here, but the following are some parameters that should be considered: maximum continuous operating voltage, ac or dc application, nominal discharge current (defined by a magnitude and waveform), voltage-protection level (the terminal voltage that is present when the SPD is discharging a specific current) and temporary overvoltage (a continuous overvoltage that can be applied for a specific time without damaging the SPD).

SPDs using different component technologies can be placed in the same circuits. However, they must be selected with care to ensure energy coordination between them. The component technology with the higher discharge rating must discharge the greatest magnitude of the available transient current while the other component technology reduces the residual transient voltage to a lower magnitude as it discharges a lesser current.

The SPD must have an integral self-protecting device that disconnects it from the circuit should the device fail. To make this disconnection apparent, many SPDs display a flag that indicates its disconnect status. Indicating the SPD's status via an integral auxiliary set of contacts is an enhanced feature that can provide a signal to a remote location. Another important product characteristic to consider is whether the SPD utilizes a finger-safe, removable module that allows a failed module to be easily replaced without tools or the need to de-energize the circuit.

## AC Surge Protection Considerations

Lightning flashes from clouds to the lightning protection system, the PV structure or a nearby ground cause a local ground-potential rise with regard to distant ground references. Conductors spanning these distances expose equipment to significant voltages. The effects of ground-potential rises are primarily experienced at the point of connection between a grid-tied PV system and the utility at the service entrance—the point where the local ground is electrically connected to a distant referenced ground.

Surge protection should be placed at the service entrance to protect the utility side of the inverter from damaging transients. The transients seen at this location are of a high magnitude and duration and therefore must be managed by surge protection with appropriately high-discharge current ratings. Controlled spark gaps used in coordination with MOVs are ideal for this purpose. Spark gap technology can discharge high lightning currents by providing an equipotential bonding function during the lightning transient. The coordinated MOV has the ability to clamp the residual voltage to an acceptable level.

In addition to the effects of ground-potential rise, the ac side of the inverter may be affected by lightning-induced and utility-switching transients that also appear at the service entrance. To minimize potential equipment damage, appropriately rated ac surge protection should be applied as close to the ac terminals of the inverter as possible, with the shortest and straightest route for conductors of sufficient cross-sectional area. Not implementing this design criterion results in higher-than-necessary voltage drop in the SPD circuit during discharge and exposes the protected equipment to higher transient voltages than necessary.

## DC Surge Protection Considerations

Direct strikes to nearby grounded structures (including the lightning protection system), and inter- and intra-cloud flashes that may be of magnitudes of 100 kA can cause associated magnetic fields that induce transient currents into PV system dc cabling. These transient voltages appear at equipment terminals and cause insulation and dielectric failures of key components.

Placing SPDs at specified locations mitigates the effect of these induced and partial lightning currents. The

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SPD is placed in parallel between the energized conductors and ground. It changes state from a high-impedance device to a low-impedance device when the overvoltage occurs. In this configuration, the SPD discharges the associated transient current, minimizing the overvoltage that would otherwise be present at the equipment terminals. This parallel device does not carry any load current. The selected SPD must be specifically designed, rated and approved for application on dc PV voltages. The integral SPD disconnect must be able to interrupt the more severe dc arc, which is not found on ac applications.

Connecting MOV modules in a Y configuration is a commonly used SPD configuration on large commercial and utility-scale PV systems operating at a maximum open-circuit voltage of 600 or 1,000 Vdc. Each leg of the Y contains an MOV module connected to each pole and to ground. In an ungrounded system, there are two modules between each pole, and between both pole and ground. In this configuration, each module is rated for half the system voltage, so even if a pole-to-ground fault occurs, the MOV modules do not exceed their rated value.

## Nonpower System Surge Protection Considerations

Just as power system equipment and components are susceptible to the effects of lightning, so is the equipment found in the measurement, control, instrumentation, SCADA and communication systems associated with these installations. In these cases, the basic concept of surge protection is the same as it is on power circuits. However, because this equipment is usually less tolerant of overvoltage impulses and more susceptible to erroneous signals and to being adversely affected by the addition of series or parallel components to the circuits, greater care must be given to the characteristics of each SPD added. Specific SPDs are called for according to whether these components are communicating through twisted pair, CAT 6 Ethernet or coaxial RF. In addition, SPDs selected for nonpower circuits must be able to discharge the transient currents without failure, to provide an adequate voltage protection level and refrain from interfering with the system's function—including series impedance, line-to-line and ground capacitance and frequency bandwidth.

## Common Misapplications of SPDs

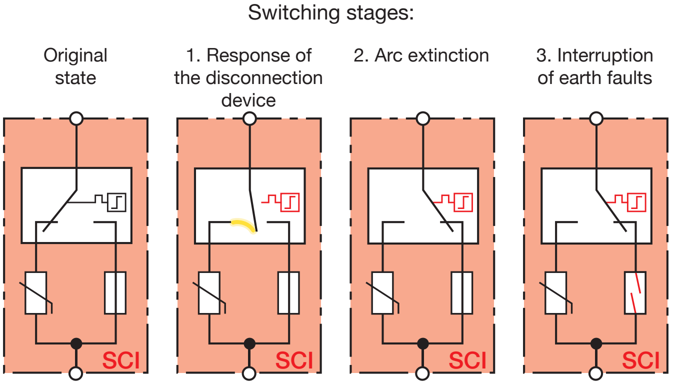
SPDs have been applied to power circuits for many years. Most contemporary power circuits are alternating current systems. As such, most surge protection equipment has been designed for use in ac systems. The relatively recent introduction of large commercial and utility-scale PV systems and the increasing number of systems deployed has, unfortunately, led to the misapplication to the dc side of SPDs designed for ac systems. In these cases, the SPDs perform improperly, especially during their failure mode, due to the characteristics of dc PV systems.

MOVs provide excellent characteristics for serving as SPDs. If they are rated properly and applied correctly, they perform in a quality manner for that function. However, like all electrical products, they may fail. Failure can be caused by ambient heating, discharging currents that are greater than the device is designed to handle, discharging too many times or being exposed to continuous overvoltage conditions.

Therefore, SPDs are designed with a thermally operated disconnecting

Courtesy SolarBOS

**Combiner with surge arrester** This SolarBOS 1,000 Vdc combiner is configured for a floating array. Grounded array configurations are also available. The three modules of the DEHNguard SPD are arranged in a fault-resistant Y circuit.




Courtesy DEHN

**Arc extinction** This series of diagrams details the 3-step dc switching process that occurs inside a DEHNguard SPD module for PV applications. Once the thermally operated disconnecting switch activates, a fused bypass circuit extinguishes the dc arc and interrupts the fault current. Individual SPD modules are easy and safe to replace.

switch that separates them from the parallel connection to the energized dc circuit should that become necessary. Since some current flows through as the SPD enters failure mode, a slight arc appears as the thermal disconnect switch operates. When applied on an ac circuit, the first zero crossing of the generator-supplied current extinguishes that arc, and the SPD is safely removed from the circuit. If that same ac SPD is applied to the dc side of a PV system, especially high voltages, there is no zero crossing of the current in a dc waveform. The normal thermally operated switch cannot extinguish the arc current, and the device fails.

Placing a parallel fused bypass circuit around the MOV is one method to overcome the extinguishing of the dc fault arc. Should the thermal disconnect operate, an arc still appears across its opening contacts; but that arc current is redirected to a parallel path containing a fuse where the arc is extinguished, and the fuse interrupts the fault current.

Upstream fusing ahead of the SPD, as may be applied on ac systems, is not appropriate on dc systems. The short-circuit available current to operate the fuse (as in an overcurrent protection device) may not be sufficient when the generator is at reduced power output. As a consequence, some SPD manufacturers have taken this into consideration in their design. UL has modified its earlier standard by its supplement to the latest surge protection standard—UL 1449. This third edition is specifically applicable to PV systems.

### SPD Checklist

In spite of the high lightning risk that many PV installations are exposed to, they can be protected by the application of SPDs and a properly engineered lightning protection system. Effective SPD implementation should include the following considerations:

- Correct placement in the system
- Termination requirements
- Proper grounding and bonding of the equipment-ground system
- Discharge rating
- Voltage protection level
- Suitability for the system in question, including dc versus ac applications
- Failure mode
- Local and remote status indication
- Easily replaceable modules
- Normal system function should be unaffected, specifically on non-power systems

*—Robert Schlesinger, PE / DEHN / Fort Pierce, FL / dehn-usa.com*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# Solar Power International 2010

**[Los Angeles, CA]** The Solar Electric Power Association and Solar Energy Industries Association have again partnered to produce North America's largest annual solar industry B-to-B event, Solar Power International (SPI). This year's conference will be held October 12–14 at the Los Angeles Convention Center. More than 27,000 attendees and 1,000 exhibitors are expected to participate. The exhibitors will showcase the industries' newest innovations for all solar technologies. Dozens of breakout sessions will be offered, covering solar policy, finance, markets and technology. Pre- and post-conference workshops will be available to participants wishing to become more familiar with specific products or installation techniques. Unlike some other solar conferences and expos in the US, the nonprofit organizers reinvest the proceeds from SPI into policy, research and educational activities that support accelerated growth of the market. SPI is sure to have something for everyone working in the industry.

**Solar Power International / 202.559.2023 / solarpowerinternational.com**

## Solmetric Introduces PV Analyzer

**[Sebastopol, CA]** The new Solmetric PVA-600 PV Analyzer is a comprehensive electrical test solution for PV arrays. Rated for 600 Vdc and 20 A, the PV Analyzer is ideal for doing performance verification tests during installation or for troubleshooting performance problems at any time. Current, voltage and power measurements are compared to the characteristics predicted by advanced performance models, which can account for actual temperature and irradiance conditions. When predicted results match modeled results, system performance is verified; any differences offer insights into potential issues. The results are wirelessly transmitted to any PC running PVA software for Windows. This software lets you specify the module and inverter type from an onboard database, as well as the number and orientation of the modules. The PVA-600 PV Analyzer includes an I-V Measurement Unit with soft carrying case, the software, a battery charger, and extension and adaptor cables. The system cost is $2,595 in the US. An optional wireless sensor kit is available for $1,495.

**Solmetric / 877.263.5026 / solmetric.com**

## SunLink Purchases Blue Oak Combiner Box Line

**[San Rafael, CA]** SunLink has added to its existing rooftop and ground-mounting solutions by acquiring Blue Oak PV Products' HomeRun combiner box line. The HomeRun product line includes combiner boxes and disconnecting combiners intended for use in commercial PV applications, listed to UL 1741 and available in steel or fiberglass enclosures. Standard combiner boxes are available in 4, 8 or 12 source-circuit configurations, while disconnecting combiners accommodate 8, 16 or 24 source circuits. Blue Oak Energy, the design and engineering firm, will continue to operate independently.

**SunLink / 415.925.9650 / sunlink.com**

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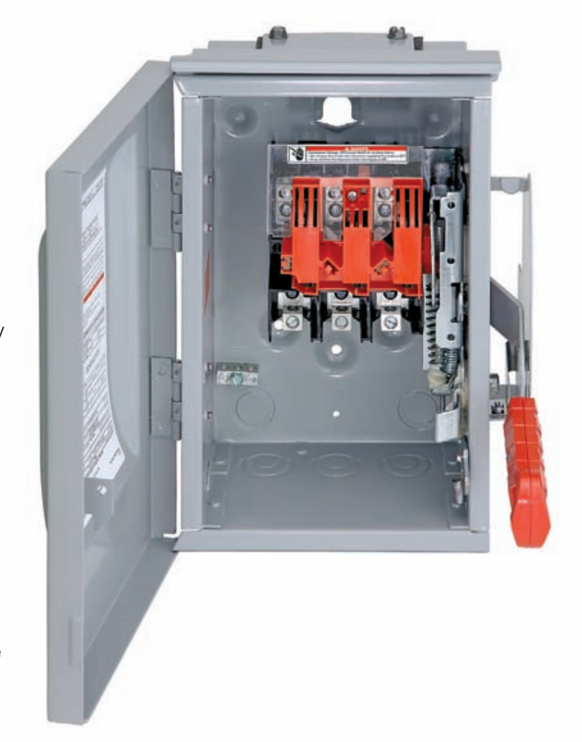


## Siemens Disconnects Rated for Three 600 Vdc Circuits

**[Norcross, GA]** Type VBII PV disconnect switches from Siemens are specifically designed for disconnecting three separate 600 Vdc circuits. Precisely aligned magnets are incorporated into each switch's line base assembly to quickly and safely extinguish the dc arc caused by disconnecting an array under load. Products in the heavy-duty switch line are listed as UL 1741 PV Disconnect Switches and also comply with UL 98 requirements. Type VBII PV disconnect switches are available in fusible and nonfusible models with 30 A, 60 A and 100 A ratings in indoor or outdoor enclosures. Standard features include a factory installed ground bus and *NEC*-required labeling, indicating that line- and load-side conductors may be energized when the switch is open. In addition, the line- and load-side lugs are larger than those in standard disconnects to accommodate conductor upsizing due to voltage drop considerations.

**Siemens Industry / 800.743.6367 / usa.siemens.com**

## Shoals Offers BOS Components

**[Portland, TN]** BOS equipment from Shoals Technologies Group includes combiner boxes, disconnecting combiners, custom wire harnesses, junction boxes, PV wire, in-line fuses, racking and PV monitoring solutions. As module prices fall and projects scale, BOS cost savings become increasingly important. This is especially true on thin-film projects with high-voltage, low-current modules that incur higher BOS costs. Shoals' custom wire harnesses provide an innovative method of utilizing material and labor efficiencies on these larger, cost-sensitive projects. Each harness is factory built to the specified length, configured with the desired terminations and prelabeled. Shoals employs a patented Interconnect System that is more reliable and durable than standard splices. Wire harnesses can be purchased separately or preinstalled in combiner boxes. An inline fuse option is available for select thin-film applications to allow some parallel connections to be made in the array field, optimizing conductor usage and reducing the total number of combiner boxes.

**Shoals Technologies Group / 615.451.1400 / shoals.com**

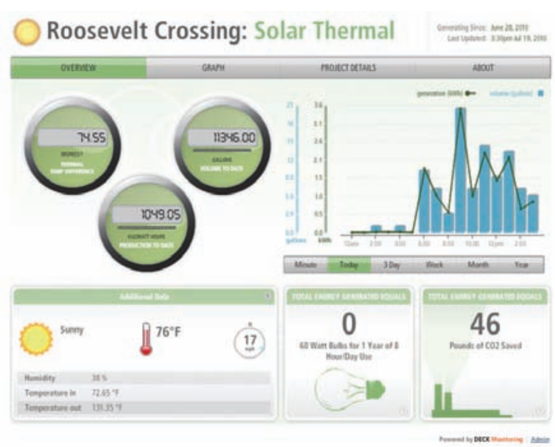
## PV Powered Upgrades Small Commercial Inverters

**[Bend, OR]** PV Powered is offering a new pair of 35 kW and 50 kW inverters. The PVP35kW and PVP50kW inverters incorporate many of the same installation and maintenance features as the company's larger units. For example, performance monitoring is housed in a separate section of the inverter, away from all power conductors, providing an added level of safety for the installer. Other installation-friendly considerations include front access for service, bottom and side cable entry points for both the ac and dc conductors, a wide range of fusing options, and integrated load-break rated disconnects for both PV input and inverter output circuits. The minimum MPPT voltage of 295 Vdc allows for flexible source-circuit design. Communication options include revenue-grade metering, string-level monitoring and the ability to connect directly to a variety of third-party monitoring solutions.

**PV Powered / 541.312.3832 / pvpowered.com**

# DECK Introduces Solar Thermal Monitoring

**[Eugene, OR]** DECK Monitoring has added two commercial solar thermal system monitoring packages to its existing suite of PV monitoring solutions. The new web-based products are configured for systems with either 2-inch or smaller inlet and outlet piping or with 2.5-inch or larger piping. Both packages include a BTU




meter and revenue-grade monitoring of six data points: two temperature probes (cold water inlet and hot water storage tank outlet), one flow-rate meter (cold water inlet), and three current transformers (CTs) for monitoring energy use for up to two pumps and one backup electric water heater. A data acquisition and logging gateway comes standard with each package. Optional add-on components consist of energy monitoring equipment for natural gas and fuel oil backup water heaters, weather stations, display devices and interactive kiosks. Data point monitoring for additional CTs and temperature probes is also available.

**DECK Monitoring / 503.224.5546 / deckmonitoring.com**

# Unistrut Launches Preengineered Racking Systems

**[Harvey, IL]** To streamline engineering analysis and product delivery, Unistrut Energy Solutions has developed cost-effective racking solutions that meet the dead and live load requirements for 75% to 80% of all commercial PV applications. This allows contractors to define racking costs without waiting for engineering analysis. Unistrut can modify the preengineered solution to meet any site-specific requirement. Options include attached or ballasted designs for rooftop or ground mounting of modules in portrait or landscape orientation. The racking solutions incorporate standard products known throughout the electrical industry from Unistrut and Allied Tube & Conduit.

**Unistrut Energy Solutions / 877.336.4332 / unistrutenergy.com**

# IREC Publishes Revised Inspection Guidelines

**[Latham, NY]** The Interstate Renewable Energy Council (IREC) released the 2010 edition of its *Field Inspection Guidelines for PV Systems.* Supported in part by the US Department of Energy, the report is authored by Bill Brooks, who also wrote the 2006 edition. Bill is well known for his contributions to PV codes and standards. In 2009, Brooks and SolarABCs released the *Expedited Permit Process for PV Systems.* The 2010 *Field Inspection Guidelines* complements that document. The *Guidelines* report is intended to consolidate the most important aspects of a field inspection into a simple process that can be performed in as little as 15 minutes. The report identifies best practices and common code violations, providing good information for inspectors and installers alike.

IREC Interstate Renewable Energy Council

**Interstate Renewable Energy Council / 518.458.6059 / irecusa.org**

# Central Inverter Trends

## in Power Plant Applications

BY GREG BALL

PV projects continue to trend toward larger systems. In 2009 and the first half of 2010, more than 26 MW of projects larger than 500 kW were installed in California under the California Solar Initiative program, which provides rebates for customer-owned generation. For the manufacturers of central inverters, particularly larger inverters, the market for power plants has great potential. Planned projects have been announced ranging from 2 to 500 MW, and even larger projects are in the works.

Distributed PV generation is on the rise, but manufacturers of large central inverters are eyeing an even bigger prize: POWER PLANTS.

The Solar Energy Industries Association reports that across the US, 129 MW of utility-scale PV plants are under construction and more than 12.5 GW are in development. Not all of these plants will be installed, but even a fraction of these numbers represents a huge increase in inverter demand. Significant commercial and power plant project development is occurring in Ontario, Canada, and throughout the Southwest and Northeast in the US. This development is also emerging in the South and Midwest.

My focus here is on inverter selection and system design considerations for large projects and power plant applications. I look at product offerings designed especially for use in power plants, where packaged equipment simplifies repetitive installation processes and interconnections are invariably at medium or high voltages. I also look at the factors influencing future inverter development, such as evolving utility requirements, codes and standards; improved safety and protection measures; and reliability and service needs.

Courtesy Satcon Technology

## PV POWER PLANTS

Here I loosely define a *power plant* as a PV system with most of these characteristics: The capacity is larger than 1 MW; installation is ground-mounted; the plant owner sells energy directly to the electric utility; and utility interconnections occur at medium or high voltage.

The vast majority of PV systems installed in North America to date are connected behind utility customers' meters, reducing their metered consumption and load, and possibly exporting through a net-metering agreement. Power plants, however, are typically not interconnected on the load side of a customer service meter. Large plants installed within military or other government or industrial complexes are notable exceptions, such as the 14 MW system at Nellis Air Force Base in Nevada.

Similarly, whereas distributed PV systems interconnect at load-side service voltages, a power plant is more likely to interconnect at distribution or transmission voltages. Medium voltage is associated with distribution system interconnections, generally from 4 to 34.5 kV, while high-voltage subtransmission or transmission level interconnections range from 69 to 500 kV.

Many commercial systems of 1 MW or larger and most, if not all, multi-megawatt power plant systems interconnect with the utility at medium- or high-voltage levels. The cabling and switchgear that collect the output of multiple dispersed inverters or inverter clusters are called *the collection system,* borrowing from the term used in wind and other conventional power plants. Because of the long distances involved, it is not economical for a collection system to operate at a low voltage such as 480 Vac and transform to medium or high voltage at the point of interconnection (POI) with the utility. At low voltage, the cable ampacity requirements and voltage drop losses are significant. It is therefore better to step up the voltage at the individual inverter clusters or stations and distribute the power on a medium-voltage collection system.

## MEGAWATTS IN A BOX

Several inverter manufacturers offer packaged solutions that include two or more inverters, a medium voltage (MV) transformer, the interconnecting switchgear, and a container or skid that houses the equipment. This essentially provides the customer with a plug-and-play solution—not that this should be equated with the ease of setting up a desktop computer. Nevertheless, the field installation and labor requirements are greatly reduced, and any engineering performed in the factory is taken out of the field. Packaged solutions are efficient because internal connections are predesigned and largely preinstalled, pad layouts and foundations are standardized, and equipment is shipped and dropped in place all together.

Broadly speaking, there are two types of packaged inverters with MV transformer configurations. One utilizes standard unipolar inverters, which incorporate a low-voltage transformer for 480 or 208 Vac output, and include an additional transformer to step up to MV levels. The other type directly couples the ac output of the inverters—typically ranging from 200 to 270 Vac—to the transformer, thereby eliminating a transformer stage. The obvious advantage to the latter is the greater overall efficiency since there is only one step-up transformer. There are limitations to this type, however. To provide the galvanic isolation needed between inverters, particularly with grounded dc systems, the transformers have separate secondary windings for each inverter. Practically, this limits the number of inverters to two per transformer. The bipolar Solaron-brand inverters from Advanced Energy (AE) are an exception. These inverters can provide a transformerless output at 480 Vac and be connected in parallel with multiple other inverters on a single transformer. Design considerations for working with AE bipolar inverters are discussed later.

Courtesy SolarCity

**Skidmount package** For a PV power plant at Intel's facility in Folsom, CA, SolarCity ordered this custom integrated 1 MW Satcon Prism solution, which includes a pair of PVS-500 (MVT) inverters and a 1,000 kVA, 3-phase, oil-filled transformer that allows for grid-interconnection at 12.47 kV.

### PACKAGED SOLUTIONS FOR THE US

The following packaged inverters with MV transformer solutions are currently offered in the US.

**PV Powered PowerVault.** The PowerVault is a packaged assembly with four capacity options ranging from 620 to 1,040 kWac. The MV-1040kW system, for example, is composed of four PVP260kW commercial inverters, a low-voltage switchboard collecting the 480 Vac inverter outputs, a fluid-filled transformer with integrated switch, and a low-voltage service panel for the tracker or other auxiliary loads. The voltage output can be specified from 4,160 V to 35 kV as needed for the project. All of the equipment except the transformer is housed in a metal container certified to UL QRNZ for walk-in electrical equipment. The transformer rests on a steel floor adjacent to the container and is bussed to the inverters using integrated wireways. The assembly is pier mounted to eliminate the need for level grading and pad foundations; the ac and dc conduits and connections can be accessed from underneath the container. The CEC efficiency of the MV-1040kW is 97% at 480 Vac, and you can expect an additional annual loss of nearly 1% in the transformer.

**Satcon Prism.** Satcon provides a range of packaged solutions and options under the Prism label, incorporating either PowerGate or Equinox series inverters. These include 600 or 900 Vdc inverters that can operate with grounded or ungrounded arrays. Configurations are available with NEMA 1 indoor inverters installed in an environmentally controlled CONTINUED ON PAGE 42

Courtesy PV Powered

**Containerized solutions** Products like this PowerVault from PV Powered offer inverters within a walk-in metal container, packaged with a medium-voltage transformer, switchgear and other associated electrical equipment.

E-house container, a prefabricated weather-tight outdoor enclosure with dual entrances, or NEMA 3R inverters installed on an outdoor skid. Satcon's newest-generation NEMA 3R inverters, the Equinox series, are designed with air-handling features that allow them to be installed either outdoors or in an E-house. In addition to a one-piece solution, with inverters and transformer in the same transportable enclosure, the company also offers a two-piece solution that allows the inverters and transformer to be separated when better suited for the installation.

**Schneider Electric PV Box.** The PV Box from Schneider Electric, which acquired Xantrex and subsequently rebranded its product line, is housed in a prefabricated building and consists of inverters, dc combiner boxes and a step-up transformer with an MV switch. Other items can be added to the package, including climate controls, security equipment, array string monitoring, SCADA monitoring equipment and power metering. Several standard configurations incorporate Xantrex GT500-MV, GT500E or GT250 inverters, including: 500 kW solar power conversion station (SPCS) for 600 Vdc and 480 V or 600 Vac; 1 MW SPCS for 600 Vdc and 15 kV to 35 kVac; 1 MW SPCS for 1,000 Vdc and 15 kV to 35 kVac; 2 MW SPCS for 1,000 Vdc and 15 kV to 35 kVac.

### PACKAGED SOLUTIONS FOR EUROPE AND ASIA

The previously described packages are commercially advertised as available here in the US, incorporating inverters listed to UL 1741 by a Nationally Recognized Testing Laboratory (NRTL). Two other inverter giants, SMA and Siemens, have a long history of providing packaged MV solutions for power plants in Europe and Asia, and more or less originated this concept for PV applications. These European inverter packages incorporate equipment certified to European (EN), International Electrotechnical Commission (IEC) and other standards. SMA's offerings in this category cover a range of capacities from 500 to 1,260 kW. Siemens currently offers packages rated from 500 to 2,000 kW. Both companies offer these products to the North American power plant market where jurisdictions allow internationally-certified equipment.

SMA is creating similar solutions that incorporate NRTL-certified inverters. SMA's Sunny Central line of inverters for applications in North America includes both indoor-rated inverters, such as the EN-certified Sunny Central 500HE-11 and Sunny Central 630HE-11, and NRTL-certified outdoor-rated units like the Sunny Central 500HE-US. The footprint of these systems allows for a multitude of configuration options to meet customer requirements, including a total enclosure, a shade structure, and pile or pad mount. Metal enclosures for housing the inverters can be sourced directly in the US.

Another notable product from SMA is the Sunny Central 800CP, which recently won an Intersolar AWARD. Designed for use in utility-scale solar power plants, it is the first outdoor-ready PV inverter larger than 500 kW. It offers 800 kVA of nominal power in combination with 98.6% efficiency. The Sunny Central 800CP's compact and weatherproof housing also makes it easy to install and provides cost savings for large PV plants. European production for the Sunny Central started in May 2010, and North American availability is anticipated in Q4.

Courtesy SMA Solar Technology

**Sunny Central 800CP** SMA's innovative new inverter for utility-scale applications is the first outdoor-rated single device with a nominal capacity of 800 kVA. Its peak continuous power is 10% higher—880 kVA—if ambient temperatures are 25°C or less.

## WHICH WAY TO GO?

The PV power plant industry in the US is in transition due to the evolution of technology here and abroad. Power plants are often defined and treated as "behind the fence" installations, which may result in certain variances from *NEC* compliance and UL listing requirements. The designation is literal in that systems are located inside industrial fencing and accessible only by authorized personnel and those under their supervision.

The *NEC* has specific language addressing its jurisdiction over power plants. For example, Article 90.2(B)(5) describes installations specifically *not* governed by the *NEC* as those "under the exclusive control of an electric utility where such installations…are on property owned or leased by the electric utility for the purpose of communications, metering, generation, control, transformation, transmission, or distribution of electric energy." This language is a bit outdated since deregulation has led to private ownership of electric generators. However, the Fine Print Note for Article 90.2(B) offers a bit more latitude, stating, "Examples of utilities may include those entities that are typically designated or recognized by governmental law or regulation by public service/utility commissions and that install, operate, and maintain electric supply (such as generation, transmission, or distribution systems)." To the extent that PV power plants are under the regulation of public service or utility commissions and beholden to the requirements of utility and independent system operators, it is difficult to make the case that these plants should be treated differently from plants owned exclusively by utilities.

The minutiae of these definitions matter because many inverter products available internationally are well suited for power plants, but they are certified to EN or IEC standards and are not listed here in North America. Without a listing to UL 1741, these inverters and associated dc BOS equipment are by definition out of compliance with the *NEC*. Several differences between inverter technologies developed on the opposite sides of the Atlantic have a significant impact on plant design, including dc voltage range, ungrounded versus grounded dc arrays, fault protection and indoor-rated versus outdoor-rated equipment.

**1,000 V systems.** The major difference between IEC certified and UL-listed products is the dc voltage range. The IEC defines low voltage as up to 1,000 Vac and 1,500 Vdc, whereas the *NEC* defines the cutoff as 600 V. Inverters manufactured in Europe for most of the past decade allowed for 1,000 V systems that actually had a 900 Vdc maximum rating. Recently, however, the ratings for some of these increased to the full 1,000 Vdc. This seemingly small difference, 300 to 400 Vdc, can have a dramatic impact on the cost of a power plant, primarily because of the enormous quantity of dc cable required to collect power from thousands of PV modules.

Higher array voltages mean fewer strings, connections and terminations; reduced ampacity cables for the same delivered power; lower percentages of voltage drop; and generally decreased inverter costs for a given capacity. Higher voltages also facilitate greater consolidation of inverter and MV equipment. For example, the economics of dc cabling at 1,000 Vdc may favor equipment pads with up to 2 MW of inverter and MV transformer capacity, whereas a 1 MW pad might be cost-effective at 600 Vdc. For a 20 MW plant, that is 10 fewer foundations, transformers, switches, fuses and all the associated connections. While there is some cost penalty associated with the need for 900 or CONTINUED ON PAGE 58

# 2010 Central Inverter Specifications Guide

| | | Input Data (dc) | | | | | Output Data (ac) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manufacturer | Model | Max. Voc (Vdc) | PV start voltage (Vdc) | MPPT range (Vdc) | Max. dc input current (Adc) | Min. dc power throughput (W) | CEC-rated power (kW) | Nominal output voltage (Vac) | Max. output current (Aac) | Max. OCPD rating (Aac) | OCPD interrupt capacity (kAic) | Neutral sizing requirements |
| Advanced Energy | Solaron 250 kW | 600 | 425 | 330–600 | 375 | DNR | 250 | 480 | 334 | 300 | 200 | 3-phase, 3-wire, no neutral required |
| Advanced Energy | Solaron 333 kW | 600 | 425 | 330–600 | 500 | DNR | 333 | 480 | 445 | 400 | 200 | 3-phase, 3-wire, no neutral required |
| Advanced Energy | Solaron 500 kW | 600 | 425 | 330–550 | 750 | DNR | 500 | 480 | 667 | 600 | 200 | 3-phase, 3-wire, no neutral required |
| Fronius USA | IG Plus 11.4-3 Delta | 600 | 245 | 230–500 | 67 | 23 | 11.4 | 208 \| 240 | 32 \| 31.2 | 40 \| 35 | DNR | no neutral required |
| Fronius USA | IG Plus 12.0-3WYE277 | 600 | 245 | 230–500 | 70 | 23 | 12 | 277 | 16.4 | 20 | DNR | same as line |
| Fronius USA | CL 33.3 Delta | 600 | 245 | 230–500 | 154 | 80 | 33.3 | 208 \| 240 | 92.5 \| 80.2 | 125 \| 100 | DNR | no neutral required |
| Fronius USA | CL 36.0 WYE277 | 600 | 245 | 230–500 | 166.5 | 80 | 36 | 277 | 43.3 | 36 | DNR | same as line |
| Fronius USA | CL 44.4 delta | 600 | 245 | 230–500 | 205.4 | 110 | 44.4 | 208 \| 240 | 123.4 \| 106.9 | 175 \| 150 | DNR | no neutral required |
| Fronius USA | CL 48.0 WYE277 | 600 | 245 | 230–500 | 222 | 110 | 48 | 277 | 57.6 | 80 | DNR | same as line |
| Fronius USA | CL 55.5 delta | 600 | 245 | 230–500 | 256.7 | 125 | 55.5 | 208 \| 240 | 154.2 \| 133.7 | 200 \| 175 | DNR | no neutral required |
| Fronius USA | CL 60.0 WYE277 | 600 | 245 | 230–500 | 277.5 | 110 | 60 | 277 | 72.2 | 90 | DNR | same as line |
| Ingeteam | INGECON SUN 15U | 600 | 300 | 300–550 | 52.6 | 170 | 15 | 208 \| 480 | 41.6 \| 18 | 50 \| 25 | 50 | 3-phase, 4-wire, neutral sized per EGC |
| Ingeteam | INGECON SUN 25U | 600 | 300 | 300–550 | 87.7 | 250 | 25 | 208 \| 480 | 69.4 \| 30 | 100 \| 50 | 50 | 3-phase, 4-wire, neutral sized per EGC |
| Ingeteam | INGECON SUN 100U | 600 | 300 | 300–550 | 360 | 600 | 100 | 208 \| 480 | 317 \| 137 | 400 \| 200 | 70 | 3-phase, 4-wire, neutral sized per EGC |
| Kaco new energy | XP 100U | 600 | 350 | 300–600 | 410 | 1,000 | 100 | 208 \| 480 | 278 \| 120 | 400 \| 150 | 65 \| 25 | same as line |
| Power-One | PVI-CENTRAL-50-US | 600 | 330 | 330–600 | 170 | DNR | 50 | 208 \| 480 | 140 \| 60 | 180 \| 78 | 65 \| 35 | N/A |
| Power-One | PVI-CENTRAL-100-US | 600 | 330 | 330–600 | 340 | DNR | 100 | 208 \| 480 | 280 \| 120 | 360 \| 156 | 65 \| 25 | N/A |

## Footnote Key

N/A–not applicable
DNR–did not report
1 Provided for reference purposes; additional clearance may be required per *Code*
2 Provided for reference purposes; size all conductors per *NEC*
3 Optional fused subcombiners provide additional terminal and cable options
4 Option to -35
5 Stainless steel option
6 At 240 Vac: start voltage = 320, MPPT = 320–600, max. dc current = 440 A
7 0.1 kW–10 kW, 1 kW default
8 Two person lift
9 Low-voltage tap option widens range to 295–500 V
10 Low-voltage tap option widens range to 285–500 V
11 For connection to MV transformer
12 With external MV transformer
13 Estimated
14 With side facing disconnects (standard)
15 With forward facing disconnect (option)
16 Conduit entry bottom
17 Conduit entry side
18 Left side 47 with conduits, 6 without conduits

| Surge Protection | | Performance | | | | | Mechanical | | | Dimensions, Clearance & Conduit Entry | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Surge protection (standard) | Surge-protection device | Peak efficiency (%) | CEC-weighted efficiency (%) | CEC night tare loss (W) | Ambient temp. range (ºF) | Elevation (ft.) | Cooling approach | Noise level with fans (dB) | Enclosure material & rating | Inverter dimensions H x W x D (in.) | Min. clearance dimensions H x W x D (in.)[1] | Min. clearance from door or access panel (in.)[1] | Approved conduit-entry zones |
| dc | DEHN | 98.2 | 97.5 | 85 | -4–122[4] | 6,000 | forced air & liquid | < 78 dB @ 10 ft | NEMA 3R, NEMA 4 (electronics) | 82 x 74 x 35 | 84 x 108 x 78 | 36 | dc: bottom, top; ac: bottom, top, back |
| dc | DEHN | 98.2 | 97.5 | 85 | -4–122[4] | 6,000 | forced air & liquid | < 78 dB @ 10 ft | NEMA 3R, NEMA 4 (electronics) | 82 x 74 x 35 | 84 x 108 x 78 | 36 | dc: bottom, top; ac: bottom, top, back |
| dc | DEHN | 98.5 | 97.5 | 85 | -4–122[4] | 6,000 | forced air & liquid | < 70 dB @ 10 ft | NEMA 3R, NEMA 4 (electronics) | 83 x 86 x 40 | 85 x 134 x 88 | 36 | dc: bottom, top; ac: bottom, top, back |
| none | none | 96.2 | 95 \| 95.5 | 0.9 \| 1 | -4–122 | N/A | forced air | 64 db (A) | NEMA 3R | 48 x 17 x 10 | 48 x 33 x 10 | 36 | bottom, right, left, back |
| none | none | 96.2 | 96 | 1 | -4–122 | N/A | forced air | 64 db (A) | NEMA 3R | 48 x 17 x 10 | 48 x 33 x 10 | 36 | bottom, right, left, back |
| none | none | 95.9 | 94.5 \| 95 | < 15 | -4–122 | 6,562 | forced air | 75 dB (A) | NEMA 3R | 76.6 x 43.5 x 31.4 | 76 x 45.5 x 49 | 42 | bottom; bottom left, right, front, back |
| none | none | 95.9 | 95.5 | < 15 | -4–122 | 6,562 | forced air | 75 dB (A) | NEMA 3R | 76.6 x 43.5 x 31.4 | 76 x 45.5 x 49 | 42 | bottom; bottom left, right, front, back |
| none | none | 95.9 | 94.5 \| 95 | < 15 | -4–122 | 6,562 | forced air | 75 dB (A) | NEMA 3R | 76.6 x 43.5 x 31.4 | 76 x 45.5 x 49 | 42 | bottom; bottom left, right, front, back |
| none | none | 95.9 | 95.5 | < 15 | -4–122 | 6,562 | forced air | 75 dB (A) | NEMA 3R | 76.6 x 43.5 x 31.4 | 76 x 45.5 x 49 | 42 | bottom; bottom left, right, front, back |
| none | none | 95.9 | 94.5 \| 95 | < 15 | -4–122 | 6,562 | forced air | 75 dB (A) | NEMA 3R | 76.6 x 43.5 x 31.4 | 76 x 45.5 x 49 | 42 | bottom; bottom left, right, front, back |
| none | none | 95.9 | 95.5 | < 15 | -4–122 | 6,562 | forced air | 75 dB (A) | NEMA 3R | 76.6 x 43.5 x 31.4 | 76 x 45.5 x 49 | 42 | bottom; bottom left, right, front, back |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 95.5 \| 97.5 | 95 | 4 | 14–149 | 6,500 | forced air | 69 dB @ 1 m | IP54 (IP65 electronics), NEMA 3R | 50 x 29.1 x 21.7 | 57.8 x 36.9 x 29.5 | 36 | bottom |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 96.1 \| 95.9 | 95.5 | 4 | 14–149 | 6,500 | forced air | 69 dB @ 1 m | IP54 (IP65 electronics), NEMA 3R | 50 x 29.1 x 21.7 | 57.8 x 36.9 x 29.5 | 36 | bottom |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 95.8 \| 96 | 95 \| 95.5 | 4 | 14–149 | 6,500 | forced air | 69 dB @ 1 m | IP20, NEMA 1 | 67.3 x 39.4 x 32.3 | 75.1 x 47.2 x 40.1 | 47 | bottom, right, left |
| ac, dc | ABB proprietary | 96.2 \| 96.5 | 95.5 \| 96 | < 62 | -5–122 | 6,500 | forced air | < 65 db | NEMA 3R[5] | 73 x 68 x 37 | 77 x 76 x 41 | 39 | bottom, left |
| ac, dc | MOV | 95.6 \| 95.7 | 95 | 33 \| 40 | 14–122 | 3,000 | forced air | 62 dB @ 1 m | zinc-plated steel, powder coated, NEMA 1 | 61.8 x 49.2 x 31.8 | 72 x 80.7 x 65 | 16 side, 32 front | bottom |
| ac, dc | MOV | 95.6 \| 95.7 | 95 | 47 \| 66 | 14–122 | 3,000 | forced air | 65 dB @ 1 m | zinc-plated steel, powder coated, NEMA 1 | 61.8 x 49.2 x 31.8 | 72 x 80.7 x 65 | 16 side, 32 front | bottom |

# 2010 Central Inverter Specifications Guide

| | | Transportation | | Termination Specifications[2] | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Manufacturer | Model | Lifting provisions | Weight (lbs.) | Number dc terminals[3] | Min. dc cable size (AWG or kcmil)[3] | Max. dc cable size (AWG or kcmil)[3] | dc terminal type[3] | Number ac terminals (per phase) | Min. ac cable size (AWG or kcmil) | Max. ac cable size (AWG or kcmil) | Number GEC terminals |
| Advanced Energy | Solaron 250 kW | forklift, eyebolts | 2,175 | 4 | 6 | 350 | compression | 2 | 6 | 500 | 5 x M10 studs |
| Advanced Energy | Solaron 333 kW | forklift, eyebolts | 2,175 | 4 | 6 | 350 | compression | 2 | 6 | 500 | 5 x M10 studs |
| Advanced Energy | Solaron 500 kW | forklift, eyebolts | 4,100 | 4 | 6 | 350 | compression | 4 | 6 | 500 | 5 x M10 studs |
| Fronius USA | IG Plus 11.4-3 Delta | none | 82 | 6 | 14 | 6 | compression | 1 | 8 | 4 | 3 |
| Fronius USA | IG Plus 12.0-3WYE277 | none | 82 | 6 | 14 | 6 | compression | 1 | 12 | 4 | 3 |
| Fronius USA | CL 33.3 Delta | forklift, eyebolts | 661 | 2 | N/A | 350 | bolts M12 | 2 x M10 | 2 | 350 | 6 x M10 bolts |
| Fronius USA | CL 36.0 WYE277 | forklift, eyebolts | 661 | 2 | N/A | 350 | bolts M12 | 2 x M10 | 6 | 350 | 6 x M10 bolts |
| Fronius USA | CL 44.4 delta | forklift, eyebolts | 721 | 2 | N/A | 350 | bolts M12 | 2 x M10 | 1/0 | 350 | 6 x M10 bolts |
| Fronius USA | CL 48.0 WYE277 | forklift, eyebolts | 721 | 2 | N/A | 350 | bolts M12 | 2 x M10 | 4 | 350 | 6 x M10 bolts |
| Fronius USA | CL 55.5 delta | forklift, eyebolts | 783 | 2 | N/A | 350 | bolts M12 | 2 x M10 | 2/0 | 350 | 6 x M10 bolts |
| Fronius USA | CL 60.0 WYE277 | forklift, eyebolts | 783 | 2 | N/A | 350 | bolts M12 | 2 x M10 | 3 | 350 | 6 x M10 bolts |
| Ingeteam | INGECON SUN 15U | forklift | 771 | DNR | 12 | 6 | DNR | 1 | 8 I 12 | 6 I 12 | DNR |
| Ingeteam | INGECON SUN 25U | forklift | 771 | DNR | 4 | 2 | DNR | 1 | 6 I 10 | 4 I 8 | DNR |
| Ingeteam | INGECON SUN 100U | forklift, eyebolts | 2,559 | DNR | 3/0 | 4/0 | DNR | 2 I 1 | 3/0 I 2/0 | 4/0 | DNR |
| Kaco new energy | XP 100U | forklift, eyebolts | 2,646 I 2,425 | 1, 2, 4 | 1/0 | 700 | crimp lug | 1 | 300 I 1 | 800 | 3 |
| Power-One | PVI-CENTRAL-50-US | forklift | 1,652 | 2 | 3/0 | 3/0 | lug | 1 | 2/0 | 250 | 1 |
| Power-One | PVI-CENTRAL-100-US | forklift | 2,203 | 4 | 3/0 | 3/0 | lug | 1 | 2/0 | 250 | 1 |

## Footnote Key

N/A–not applicable
DNR–did not report
[1] Provided for reference purposes; additional clearance may be required per *Code*
[2] Provided for reference purposes; size all conductors per *NEC*
[3] Optional fused subcombiners provide additional terminal and cable options
[4] Option to -35
[5] Stainless steel option
[6] At 240 Vac: start voltage = 320, MPPT = 320–600, max. dc current = 440 A
[7] 0.1 kW–10 kW, 1 kW default
[8] Two person lift
[9] Low-voltage tap option widens range to 295–500 V
[10] Low-voltage tap option widens range to 285–500 V
[11] For connection to MV transformer
[12] With external MV transformer
[13] Estimated
[14] With side facing disconnects (standard)
[15] With forward facing disconnect (option)
[16] Conduit entry bottom
[17] Conduit entry side
[18] Left side 47 with conduits, 6 without conduits

| | | Disconnects & Subcombiners | | | Listing | | Data | Warranty | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Min. GEC cable size (AWG or kcmil) | Max. GEC cable size (AWG or kcmil) | dc disconnect (load-break rated?) | ac disconnect (load-break rated?) | Integral fused subcombiner[3] | Listing agency | Safety listings and certifications | Type of databus | Standard (yr.) | Extended (yr.) | PM or service contract option |
| N/A | N/A | N/A | N/A | N/A | CSA | UL 1741 US & Canada | RS-232, RS-422, RS-485, Ethernet, PCMCIA, Modbus-TCP/IP & RTU | 5 | 10, 15 | yes |
| N/A | N/A | N/A | N/A | N/A | CSA | UL 1741 US & Canada | RS-232, RS-422, RS-485, Ethernet, PCMCIA, Modbus-TCP/IP & RTU | 5 | 10, 15 | yes |
| N/A | N/A | N/A | N/A | N/A | CSA | UL 1741 US & Canada | RS-232, RS-422, RS-485, Ethernet, PCMCIA, Modbus-TCP/IP & RTU | 5 | 10, 15 | yes |
| 8 | 4 | standard (yes) | standard (yes) | 6 x 20 A | CSA | UL 1741, IEEE 1547 | option: Fronius solar.net, RS-485 | 10 | 15 | no |
| 12 | 4 | standard (yes) | standard (yes) | 6 x 20 A | CSA | UL 1741, IEEE 1547 | option: Fronius solar.net, RS-485 | 10 | 15 | no |
| 2 | 350 | standard (yes) | standard (yes) | no | CSA | UL 1741, IEEE 1547 | Fronius solar.net, RS-485 | 10 | 15 | no |
| 2 | 350 | standard (yes) | standard (yes) | no | CSA | UL 1741, IEEE 1547 | Fronius solar.net, RS-485 | 10 | 15 | no |
| 2 I 1/0 | 350 | standard (yes) | standard (yes) | no | CSA | UL 1741, IEEE 1547 | Fronius solar.net, RS-485 | 10 | 15 | no |
| 4 | 350 | standard (yes) | standard (yes) | no | CSA | UL 1741, IEEE 1547 | Fronius solar.net, RS-485 | 10 | 15 | no |
| 2/0 | 350 | standard (yes) | standard (yes) | no | CSA | UL 1741, IEEE 1547 | Fronius solar.net, RS-485 | 10 | 15 | no |
| 3 | 350 | standard (yes) | standard (yes) | no | CSA | UL 1741, IEEE 1547 | Fronius solar.net, RS-485 | 10 | 15 | no |
| DNR | DNR | standard (yes) | standard (yes) | option: 10 inputs | CSA | UL 1741, CSA 107.1-01 | RS-485, Ethernet | 5 | 20 | yes |
| DNR | DNR | standard (yes) | standard (yes) | DNR | CSA | UL 1741, CSA 107.1-01 | RS-485, Ethernet | 5 | 20 | yes |
| DNR | DNR | standard (yes) | standard (yes) | DNR | CSA | UL 1741, CSA 107.1-01 | RS-485, Ethernet | 5 | 20 | yes |
| 2 | 600 | standard (yes) | standard (yes) | yes | ETL | UL 1741, CSA 107.1-01 | RS-232, RS-485, Ethernet | 5 | 10, 15, 20 | yes |
| 2/0 | 250 | standard (yes) | standard (yes) | 1 x 200 A | CSA | UL 1741 US & Canada, FCC Class C | RS-485 | 5 | 10, 15, 20 | yes |
| 2/0 | 250 | standard (yes) | standard (yes) | 2 x 200 A | CSA | UL 1741 US & Canada, FCC Class C | RS-485 | 5 | 10, 15, 20 | yes |

# 2010 Central Inverter Specifications Guide

| | | Input Data (dc) | | | | | Output Data (ac) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manufacturer | Model | Max. Voc (Vdc) | PV start voltage (Vdc) | MPPT range (Vdc) | Max. dc input current (Adc) | Min. dc power throughput (W) | CEC-rated power (kW) | Nominal output voltage (Vac) | Max. output current (Aac) | Max. OCPD rating (Aac) | OCPD interrupt capacity (kAic) | Neutral sizing requirements |
| PV Powered | PVP30kW-LV | 600 | 300 | 295–500 | 109 | DNR | 30 | 208 \| 480 | 83 \| 36 | 125 \| DNR | 50 | 3-phase, 3-wire, no neutral required |
| PV Powered | PVP35kW | 600 | 300 | 295–500 | 125 | DNR | 35 | 208 \| 480 | 100 \| 54 | 150 \| 60 | 100 | 3-phase, 3-wire, no neutral required |
| PV Powered | PVP50kW | 600 | 300 | 295–500 | 177 | DNR | 50 | 208 \| 480 | 143 \| 62 | 200 \| 100 | 100 | 3-phase, 3-wire, no neutral required |
| PV Powered | PVP75kW | 600 | 300 | 295–500 | 267 | DNR | 75 | 208 \| 480 | 208 \| 90 | 350 \| 150 | 100 | 3-phase, 3-wire, no neutral required |
| PV Powered | PVP100kW | 600 | 300 | 295–500 | 356 | DNR | 100 | 208 \| 480 | 278 \| 120 | 400 \| 200 | 100 | 3-phase, 3-wire, no neutral required |
| PV Powered | PVP260kW | 600 | 300 | 295–500 | 918 | DNR | 260 | 480 | 301 | 400 | 100 | 3-phase, 3-wire, no neutral required |
| PV Powered | PVP260kW-LV | 600 | 300 | 295–500 | 1,022 | DNR | 260 | 480 | 301 | 400 | 100 | 3-phase, 3-wire, no neutral required |
| Satcon Technology | PVS-30 | 600 | 305 | 305–600 | 104 | 500 | 30 | 208 \| 240 \| 480 | 84 \| 72 \| 36 | 100 \| 85 \| 44 | DNR | 3-phase, 3-wire, no neutral required |
| Satcon Technology | PVS-50 | 600 | 305 | 305–600 | 172 | 500 | 50 | 208 \| 240 \| 480 | 139 \| 121 \| 60 | 167 \| 145 \| 72 | 65 \| 65 \| 25 | 3-phase, 3-wire, no neutral required |
| Satcon Technology | PVS-75 | 600 | 315 | 315–600 | 248 | 500 | 75 | 208 \| 240 \| 480 | 208 \| 181 \| 91 | 250 \| 217 \| 109 | 65 \| 65 \| 25 | 3-phase, 3-wire, no neutral required |
| Satcon Technology | PVS-100 | 600 | 315 | 315–600 | 331 | 500 | 100 | 208 \| 240 \| 480 | 278 \| 241 \| 121 | 334 \| 288 \| 145 | 65 \| 65 \| 25 | 3-phase, 3-wire, no neutral required |
| Satcon Technology | PVS-135 | 600 | 310[6] | 310-600[6] | 454[6] | 500 | 135 | 208 \| 240 \| 480 | 375 \| 325 \| 163 | 450 \| 390 \| 196 | 65 \| 65 \| 25 | 3-phase, 3-wire, no neutral required |
| Satcon Technology | PVS-250 | 600 | 320 | 320–600 | 814 | 500 | 250 | 208 \| 240 \| 480 | 694 \| 601 \| 301 | 833 \| 723 \| 362 | 100 \| 100 \| 35 | 3-phase, 3-wire, no neutral required |
| Satcon Technology | PVS-375 | 600 | 320 | 320–600 | 1,227 | 500 | 375 | 480 | 451 | 542 | 50 | 3-phase, 3-wire, no neutral required |
| Satcon Technology | PVS-500 | 600 | 320 | 320–600 | 1,628 | 500 | 500 | 480 | 602 | 753 | 50 | 3-phase, 3-wire, no neutral required |
| Satcon Technology | PVS-1000 | 900 | 420 | 420–850 | 2,442 | 500 | 1,000 | 265 | 2,178 | 2,614 | DNR | 3-phase, 3-wire, no neutral required |
| Satcon Technology | SDMS-0100 | 600 | 100 | 250–575 | 108 | 500 | 100 | 208 \| 240 \| 480 | 278 \| 241 \| 120 | 334 \| 289 \| 190 | 65 \| 65 \| 25 | 3-phase, 3-wire, no neutral required |
| Schneider Electric | Xantrex GT30 | 430 | 300 | 180–425 | 80 | < 300 | 28.8 | 208 | 80 | 100 | 65 | same as phase conductors |
| Schneider Electric | Xantrex GT100 | 600 | 440 | 300–600 | 347 | variable[7] | 100 | 208 \| 480 | 287 \| 121 | 400 \| 200 | 25 | 3-phase, 4-wire, neutral sized per EGC |
| Schneider Electric | Xantrex GT250 | 600 | 440 | 300–600 | 867 | variable[7] | 250 | 480 | 301 | 400 | 25 | 3-phase, 4-wire, neutral sized per EGC |
| Schneider Electric | Xantrex GT500 MVX | 600 | 440 | 310–480 | 1,700 | variable[7] | 500 | 208 | 1,388 | 1,800 | 65 | 3-phase, 3-wire, no neutral required |

## Footnote Key

N/A–not applicable
DNR–did not report
[1] Provided for reference purposes; additional clearance may be required per *Code*
[2] Provided for reference purposes; size all conductors per *NEC*
[3] Optional fused subcombiners provide additional terminal and cable options
[4] Option to -35
[5] Stainless steel option
[6] At 240 Vac: start voltage = 320, MPPT = 320–600, max. dc current = 440 A
[7] 0.1 kW–10 kW, 1 kW default
[8] Two person lift
[9] Low-voltage tap option widens range to 295–500 V
[10] Low-voltage tap option widens range to 285–500 V
[11] For connection to MV transformer
[12] With external MV transformer
[13] Estimated
[14] With side facing disconnects (standard)
[15] With forward facing disconnect (option)
[16] Conduit entry bottom
[17] Conduit entry side
[18] Left side 47 with conduits, 6 without conduits

| Surge Protection | | Performance | | | | | Mechanical | | | Dimensions, Clearance & Conduit Entry | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Surge protection (standard) | Surge-protection device | Peak efficiency (%) | CEC-weighted efficiency (%) | CEC night tare loss (W) | Ambient temp. range (ºF) | Elevation (ft.) | Cooling approach | Noise level with fans (dB) | Enclosure material & rating | Inverter dimensions H x W x D (in.) | Min. clearance dimensions H x W x D (in.)[1] | Min. clearance from door or access panel (in.)[1] | Approved conduit-entry zones |
| ac | MOV | 94.4 \| 94.7 | 93 \| 93.5 | 17 | -13–113 | 6,000 | forced air, convection | < 60 dB @ 1 m | aluminum, powder coated, NEMA 3R | 47.8 x 30.4 x 25.8 | 47.8 x 102.4 x 39.8 | 36 | back, left, right |
| ac, dc | MOV | 96.6 | 95.5 | 25 | -22–122 | 6,000 | forced air, convection | < 55 dB @ 1 m | powder-coated steel, NEMA 4 | 75.6 x 48.8 x 34.5 | 75.6 x 48.8 x 70.5 | 36 | bottom, left, right |
| ac, dc | MOV | 97.1 | 96 | 25 | -22–122 | 6,000 | forced air, convection | < 55 dB @ 1 m | powder-coated steel, NEMA 4 | 75.6 x 48.8 x 34.5 | 75.6 x 48.8 x 70.5 | 36 | bottom, left, right |
| ac, dc | MOV | 96.1 \| 96.6 | 95.5 | 42 | -22–122 | 6,000 | forced air, convection | < 60 dB @ 1 m | powder-coated steel, NEMA 4 | 92.4 x 62.6 x 35 | 92.4 x 62.6 x 71 | 36 | bottom, left, right |
| ac, dc | MOV | 96.3 \| 97.1 | 95.5 \| 96 | 42 | -22–122 | 6,000 | forced air, convection | < 60 dB @ 1 m | powder-coated steel, NEMA 4 | 92.4 x 62.6 x 35 | 92.4 x 62.6 x 71 | 36 | bottom, left, right |
| ac, dc | MOV | 97.7 | 97 | 75 | -22–122 | 6,000 | forced air, convection | < 70 dB @ 1 m | powder-coated steel, NEMA 4 | 93 x 104 x 41.4 | 93 x 104 x 77.4 | 36 | bottom, left, right |
| ac, dc | MOV | 97.8 | 96.5 | 75 | -22–122 | 6,000 | forced air, convection | < 70 dB @ 1 m | powder-coated steel, NEMA 4 | 93 x 104 x 41.4 | 93 x 104 x 77.4 | 36 | bottom, left, right |
| ac, dc | dc: CKE Z575PA80C ac: DELTA LA603G | 95.7 \| 96 \| 95.6 | 95 | 76 \| 65 \| 72 | -4–122 | 3,000 | forced air | < 65 dB (A) | G90 steel, powder coated, NEMA 3R | 74 x 30 x 27 | 74 x 30 x 63 | 36 | bottom, left, right |
| ac, dc | dc: CKE Z575PA80C ac: DELTA LA603G | 95.9 \| 96.2 \| 96.4 | 95.5 | 76 \| 94 \| 77 | -4–122 | 3,000 | forced air | < 65 dB (A) | G90 steel, powder coated, NEMA 3R | 74 x 45 x 27 | 74 x 30 x 63 | 36 | bottom, left, right |
| ac, dc | dc: CKE Z575PA80C ac: DELTA LA603G | 96.6 \| 96.6 \| 96.7 | 96 | 65 \| 72 \| 70 | -4–122 | 3,000 | forced air | < 65 dB (A) | G90 steel, powder coated, NEMA 3R | 80 x 57 x 31 | 80 x 57 x 67 | 36 | bottom, left, right |
| ac, dc | dc: CKE Z575PA80C ac: DELTA LA303G | 96.6 \| 96.5 \| 96.7 | 96 | 62 \| 62 \| 66 | -4–122 | 3,000 | forced air | < 65 dB (A) | G90 steel, powder coated, NEMA 3R | 80 x 57 x 31 | 80 x 57 x 67 | 36 | bottom, left, right |
| ac, dc | dc: CKE Z575PA80C ac: DELTA LA303G | 96.5 \| 96.6 \| 96.7 | 96 | 63 \| 64 \| 64 | -4–122 | 3,000 | forced air | < 65 dB (A) | G90 steel, powder coated, NEMA 3R | 80 x 65 x 31 | 80 x 65 x 67 | 36 | bottom, left, right |
| ac, dc | dc: surge arrestor ac: MOV | 96.5 \| 96.6 \| 96.6 | 96 | 105 \| 100 \| 120 | -4–122 | 3,000 | forced air | < 65 dB (A) | G90 steel, powder coated, NEMA 3R | 89 x 115 x 38 | 89 x 115 x 74 | 36 | bottom, left, right |
| ac, dc | dc: DELTA LA602DC ac: MCG 439-080-07 | 96.3 | 95.5 | 124 | -4–122 | 3,000 | forced air | < 65 dB (A) | G90 steel, powder coated, NEMA 3R | 89 x 106 x 40 | 89 x 106 x 88 | 48 | primarily bottom |
| ac, dc | dc: DELTA LA602DC ac: MCG 439-080-07 | 96.5 | 96 | 138 | -4–122 | 3,000 | forced air | < 65 dB (A) | G90 steel, powder coated, NEMA 3R | 93 x 139 x 43 | 93 x 139 x 91 | 48 | primarily bottom |
| ac, dc | dc: surge arrestor ac: MOV | 96.9 | 96 | 396 | -4–122 | 3,000 | forced air | < 65 dB (A) | RAL 7032, NEMA 3R | 93 x 139 x 71 | 93 x 139 x 167 | 48 | bottom |
| ac, dc | dc: surge arrestor ac: MOV | 97.1 \| 96.7 \| 96.6 | 96.5 | 60.4 \| 61.8 \| 63.9 | -4–131 | 3,000 | forced air | < 65 dB (A) | RAL 7035, NEMA 3R | 68 x 86 x 23 | 68 x 86 x 51 | 28 | primarily bottom |
| ac, dc | Epcos high-energy MOVs | 97 | 96 | < 20 | -4–122 | 6,600 | forced air | DNR | powder-coated aluminum, NEMA 3R | 42.2 x 22 x 13.9 | 42.2 x 48 x 49.9 | 36 | bottom only |
| ac, dc | dc: Delta LA602 ac: EFI TSA36-3 | 96.2 \| 96.7 | 95 \| 96 | 95 \| 92 | 5–122 | 6,600 | forced air | 75 dB @ 6 ft | zinc-coated & powder-coated steel, NEMA 3R | 73.3 x 67 x 46.1 | 85.3 x 67 x 82.1 | 36 | bottom, left, right |
| ac, dc | dc: Delta LA602 ac: EFI TSA36-3 | 96.8 | 96 | 34 | 5–122 | 6,600 | forced air | 75 dB @ 6 ft | zinc-coated & powder-coated steel, NEMA 3R | 86.3 x 90 x 46.1 | 98.3 x 90 x 82.1 | 36 | bottom, left, right |
| ac, dc | dc: Delta LA602 ac: EFI TSA36-3 | 98 | 97 | 161 | -4–113 | 6,600 | forced air | 75 dB @ 6 ft | zinc-coated & powder-coated steel, NEMA 3R | 88.4 x 90 x 49.6 | 100.4 x 90 x 85.6 | 36 | bottom, left, right |

# 2010 Central Inverter Specifications Guide

| | | Transportation | | Termination Specifications[2] | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Manufacturer | Model | Lifting provisions | Weight (lbs.) | Number dc terminals[3] | Min. dc cable size (AWG or kcmil)[3] | Max. dc cable size (AWG or kcmil)[3] | dc terminal type[3] | Number ac terminals (per phase) | Min. ac cable size (AWG or kcmil) | Max. ac cable size (AWG or kcmil) | Number GEC terminals |
| PV Powered | PVP30kW-LV | forklift | 760 | 1, 3 | 6 | 350 | lug | 1 | 2 | 2/0 | 4 |
| PV Powered | PVP35kW | forklift (front or back) | 1,200 | 4 | N/A | N/A | holes on busbar | 4 x M10 holes | N/A | N/A | 4 x M10 holes |
| PV Powered | PVP50kW | forklift (front or back) | 1,500 | 4 | N/A | N/A | holes on busbar | 4 x M10 holes | N/A | N/A | 4 x M10 holes |
| PV Powered | PVP75kW | forklift (front or back) | 2,750 | 32 | N/A | N/A | holes on busbar | 16 x M10 holes | N/A | N/A | 16 x M10 holes |
| PV Powered | PVP100kW | forklift (all sides) | 3,000 | 32 | N/A | N/A | holes on busbar | 16 x M10 holes | N/A | N/A | 16 x M10 holes |
| PV Powered | PVP260kW | forklift (front or back) | 4,800 | 32 | N/A | N/A | holes on busbar | 16 x M10 holes | N/A | N/A | 17 x M10 holes |
| PV Powered | PVP260kW-LV | forklift (front or back) | 4,800 | 32 | N/A | N/A | holes on busbar | 16 x M10 holes | N/A | N/A | 18 x M10 holes |
| Satcon Technology | PVS-30 | forklift | 1,204 | 5 | N/A | N/A | holes on busbar | 1 | 1 I 2 I 6 | 1/0 | 2 |
| Satcon Technology | PVS-50 | forklift | 1,732 | 5 | N/A | N/A | holes on busbar | 1 | 4/0 I 3/0 I 3 | 300 I 300 I 2/0 | 2 |
| Satcon Technology | PVS-75 | forklift | 2,150 | 6 | N/A | N/A | holes on busbar | 1 | 300 I 300 I 1/0 | 500 I 500 I 350 | 2 |
| Satcon Technology | PVS-100 | forklift | 2,350 | 6 | N/A | N/A | holes on busbar | 2 I 2 I 1 | 4/0 I 3/0 I 3/0 | 250 I 250 I 350 | 2 |
| Satcon Technology | PVS-135 | forklift | 2,684 | 9 | N/A | N/A | holes on busbar | 2 | 350 I 250 I 250 | 500 I 500 I 250 | 2 |
| Satcon Technology | PVS-250 | forklift | 2,930 | 15 | N/A | N/A | holes on busbar | 4 I 4 I 2 | 350 I 350 I 250 | 500 | 1 |
| Satcon Technology | PVS-375 | forklift (w/ spreader bar) | 3,300 | 24 | N/A | N/A | holes on busbar | 4 | 500 | 500 | 1 |
| Satcon Technology | PVS-500 | forklift (w/ spreader bar) | 5,900 | 30 | N/A | N/A | holes on busbar | 4 | 700 | 700 | 1 |
| Satcon Technology | PVS-1000 | eyebolts | 12,000 | 40 | N/A | N/A | holes on busbar | 10 | 700 | 700 | N/A |
| Satcon Technology | SDMS-0100 | forklift | 2,605 | 6 | N/A | N/A | holes on busbar | 2 I 2 I 1 | 250 I 3/0 I 3/0 | 250 I 250 I 300 | 2 |
| Schneider Electric | Xantrex GT30 | none required[8] | 165 | 1 | 1/0 | 1/0 | box | 1 | 2 | 1/0 | 4 |
| Schneider Electric | Xantrex GT100 | forklift, eyebolts | 3,000 | 6 | N/A | N/A | stud | 1 x M10 hole | N/A | N/A | 1 x M10 hole |
| Schneider Electric | Xantrex GT250 | forklift, eyebolts | 4,450 | 7 | N/A | N/A | stud | 1 x M10 hole | N/A | N/A | 1 x M10 hole |
| Schneider Electric | Xantrex GT500 MVX | forklift, eyebolts | 3,500 | 16 | N/A | N/A | stud | 3 x M10 holes | N/A | N/A | 2 x M10 hole |

## Footnote Key

N/A–not applicable
DNR–did not report
[1] Provided for reference purposes; additional clearance may be required per *Code*
[2] Provided for reference purposes; size all conductors per *NEC*
[3] Optional fused subcombiners provide additional terminal and cable options
[4] Option to -35
[5] Stainless steel option
[6] At 240 Vac: start voltage = 320, MPPT = 320–600, max. dc current = 440 A
[7] 0.1 kW–10 kW, 1 kW default
[8] Two person lift
[9] Low-voltage tap option widens range to 295–500 V
[10] Low-voltage tap option widens range to 285–500 V
[11] For connection to MV transformer
[12] With external MV transformer
[13] Estimated
[14] With side facing disconnects (standard)
[15] With forward facing disconnect (option)
[16] Conduit entry bottom
[17] Conduit entry side
[18] Left side 47 with conduits, 6 without conduits

| | | Disconnects & Subcombiners | | | Listing | | Data | Warranty | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Min. GEC cable size (AWG or kcmil) | Max. GEC cable size (AWG or kcmil) | dc disconnect (load-break rated?) | ac disconnect (load-break rated?) | Integral fused subcombiner[3] | Listing agency | Safety listings and certifications | Type of databus | Standard (yr.) | Extended (yr.) | PM or service contract option |
| DNR | DNR | standard (yes) | standard (yes) | 1 x 125 A | ETL | UL 1741, IEEE 1547, FCC Class A & B | Ethernet and Modbus | 10 | 20 | yes |
| DNR | DNR | standard (yes) | standard (yes) | option: 1–3 fuses, 225 A total | ETL | UL 1741, IEEE 1547, FCC Class A & B | Ethernet and Modbus | 10 | 20 | yes |
| DNR | DNR | standard (yes) | standard (yes) | option: 1–4 fuses, 350 A total | ETL | UL 1741, IEEE 1547, FCC Class A & B | Ethernet and Modbus | 10 | 20 | yes |
| DNR | DNR | standard (yes) | standard (yes) | option: 9 x 50 A, 6 x 75 A, 3 x 150 A, 2 x 225 A, 1 x 450 A | ETL | UL 1741, IEEE 1547, FCC Class A & B | Ethernet and Modbus | 10 | 20 | yes |
| DNR | DNR | standard (yes) | standard (yes) | option: 11 x 75 A, 6 x 100 A, 3 x 200 A, 2 x 300 A, 1 x 600 A | ETL | UL 1741, IEEE 1547, FCC Class A & B | Ethernet and Modbus | 10 | 20 | yes |
| DNR | DNR | standard (yes) | standard (yes) | options from: 20 x 75 A to 4 x 400 A | ETL | UL 1741, IEEE 1547, FCC Class A | Ethernet and Modbus | 10 | 20 | yes |
| DNR | DNR | standard (yes) | standard (yes) | options from: 20 x 75 A to 4 x 400 A | ETL | UL 1741, IEEE 1547, FCC Class A | Ethernet and Modbus | 10 | 20 | yes |
| 6 \| 6 \| 10 | 4/0 | standard (no) | standard (no) | option: 4 x 50 A, 5 x 40 A | CSA | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | available | yes |
| 6 \| 6 \| 8 | 4/0 | standard (no) | standard (no) | option: 4 x 80 A, 5 x 60 A | CSA | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | available | yes |
| 4 \| 4 \| 6 | 4/0 | standard (no) | standard (no) | option: 5 x 100 A, 6 x 80 A | CSA | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | available | yes |
| 3 \| 3 \| 6 | 4/0 | standard (no) | standard (no) | option: 5 x 110 A, 6 x 100 A | CSA | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | available | yes |
| 2 \| 2 \| 4 | 4/0 | standard (no) | standard (no) | option: 5 x 160 A, 9 x 100 A | CSA | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | available | yes |
| 3/0 \| 3/0 \| 2 | 250 | standard (no) | standard (no) | option: 15 x 100 A, 10 x 160 A | CSA | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | available | yes |
| 1/0 | 350 | standard (no) | standard (no) | option: 15 x 160 A, 24 x 100 A | CSA | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | available | yes |
| 2/0 | 350 | standard (no) | standard (no) | option: 20 x 160 A, 30 x 100 A | CSA | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | available | yes |
| N/A | N/A | standard (no) | standard (no) | option: 28 x 160 A, 40 x 100 A | CSA | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | 10, 15, 20 | yes |
| 3 \| 3 \| 6 | 4/0 | standard (no) | standard (no) | option: 4 x 100 A, 5 x 80 A, 6 x 80 A | CSA | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | 10, 15, 20 | yes |
| 2 | 1/0 | standard (yes) | standard (yes) | none | CSA | UL 1741 US & Canada, FCC Class A | RS-232, RS-485, Modbus | 5 | 10, 15 | yes |
| N/A | N/A | standard (no) | standard (yes) | option: 6 x 100 A, 4 x 150 A, 3 x 200 A | CSA | UL 1741 US & Canada, FCC Class A | RS-485, Modbus, Ethernet | 5 | 10, 15 | yes |
| N/A | N/A | standard (no) | standard (yes) | option: 15 x 100 A, 10 x 150 A, 7 x 200 A | CSA | UL 1741 US & Canada, FCC Class A | RS-485, Modbus, Ethernet | 5 | 10, 15 | yes |
| N/A | N/A | standard (no) | standard (yes) | option: 30 x 100 A, 16 x 200 A | CSA | UL 1741 US & Canada | RS-485, Modbus, Ethernet | 5 | 10, 15 | yes |

# 2010 Central Inverter Specifications Guide

| | | Input Data (dc) | | | | | Output Data (ac) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manufacturer | Model | Max. Voc (Vdc) | PV start voltage (Vdc) | MPPT range (Vdc) | Max. dc input current (Adc) | Min. dc power throughput (W) | CEC-rated power (kW) | Nominal output voltage (Vac) | Max. output current (Aac) | Max. OCPD rating (Aac) | OCPD interrupt capacity (kAic) | Neutral sizing requirements |
| Siemens Industry | SINVERT PVS351 UL | 600 | 330 | 330–480 | 1,103 | 2,600 | 350 | 480 | 424 | 500 | 65 | 3-phase, 3-wire, no neutral required |
| Siemens Industry | SINVERT PVS701 UL | 600 | 330 | 330–480 | 2,206 | 2,600 | 700 | 480 | 848 | 2 x 500 | 130 | 3-phase, 3-wire, no neutral required |
| Siemens Industry | SINVERT PVS1051 UL | 600 | 330 | 330–480 | 3,309 | 2,600 | 1,050 | 480 | 1,272 | 3 x 500 | 195 | 3-phase, 3-wire, no neutral required |
| Siemens Industry | SINVERT PVS1401 UL | 600 | 330 | 330–480 | 4,412 | 2,600 | 1,400 | 480 | 1,696 | 4 x 500 | 260 | 3-phase, 3-wire, no neutral required |
| SMA Solar Technology | ST 36 | 600 | 300 | 250–480 | 150 | DNR | 36 | 208 \| 240 \| 277 | 100 \| 87 \| 44 | 125 \| 110 \| 60 | DNR | 3-phase, 4-wire, neutral sized per EGC |
| SMA Solar Technology | ST 42 | 600 | 300 | 250–480 | 180 | DNR | 42 | 208 \| 240 \| 277 | 117 \| 101 \| 51 | 150 \| 125 \| 70 | DNR | 3-phase, 4-wire, neutral sized per EGC |
| SMA Solar Technology | ST 48 | 600 | 365 | 300-480 | 180 | DNR | 45.6 \| 48 | 240 \| 277 | 110 \| 58 | 150 \| 80 | DNR | 3-phase, 4-wire, neutral sized per EGC |
| SMA Solar Technology | SC 250U | 600 | 400 | 330–600 | 800 | 5,000 | 250 | 480 | 300 | 450 | ac contactor (no breaker) | 3-phase, 4-wire, neutral sized per EGC |
| SMA Solar Technology | SC 500U | 600 | 400 | 330–600 | 1,600 | 5,000 | 500 | 480 | 600 | 900 | ac contactor (no breaker) | 3-phase, 4-wire, neutral sized per EGC |
| SMA Solar Technology | SC 500HE-US | 600 | 400 | 330–600 | 1,600 | 5,000 | 500 | 200[11] | 1,470 | DNR | 42 (breaker) | 3-phase, 4-wire, neutral sized per EGC |
| Solectria Renewables | PVI 13kW | 475 | 270 | 205–385 | 68 | 300 | 13.2 | 208 \| 480 | 37 \| 16 | 50 \| 40 | 200 | 3-phase, 3-wire, no neutral required |
| Solectria Renewables | PVI 15kW | 475 | 270 | 205–385 | 77 | 300 | 15 | 208 \| 480 | 42 \| 18 | 60 \| 40 | 200 | 3-phase, 3-wire, no neutral required |
| Solectria Renewables | PVI 60kW | 600 | 390 | 312–500[9] | 201 | 520 | 60 | 208 \| 480 | 166 \| 73 | 250 \| 125 | 200 | 3-phase, 3-wire, no neutral required |
| Solectria Renewables | PVI 82kW | 600 | 390 | 312–500[9] | 275 | 590 | 82 | 208 \| 480 | 229 \| 100 | 300 \| 150 | 200 | 3-phase, 3-wire, no neutral required |
| Solectria Renewables | PVI 95kW | 600 | 390 | 312–500[9] | 319 | 590 | 95 | 208 \| 480 | 261 \| 115 | 350 \| 150 | 200 | 3-phase, 3-wire, no neutral required |
| Solectria Renewables | SGI 225 | 600 | 370 | 300–500[10] | 780 | 780 | 225 | 208 \| 480 | 624 \| 271 | 800 \| 350 | 65 \| 18 | 3-phase, 3-wire, no neutral required |
| Solectria Renewables | SGI 250 | 600 | 370 | 300–500[10] | 864 | 870 | 250 | 208 \| 480 | 693 \| 301 | 1,000 \| 400 | 65 \| 18 | 3-phase, 3-wire, no neutral required |
| Solectria Renewables | SGI 266 | 600 | 370 | 300–500[10] | 918 | 870 | 266 | 208 \| 480 | 738 \| 320 | 1,000 \| 400 | 65 \| 18 | 3-phase, 3-wire, no neutral required |
| Solectria Renewables | SGI 300 | 600 | 370 | 300–500[10] | 1,036 | 870 | 300 | 208 \| 480 | 832 \| 360 | 1,200 \| 450 | 65 \| 18 | 3-phase, 3-wire, no neutral required |
| Solectria Renewables | SGI 500 | 600 | 370 | 300–500[10] | 1,727 | 1,120 | 500 | 208 \| 480 | 1,388 \| 600 | 2,000 \| 800 | 65 \| 18 | 3-phase, 3-wire, no neutral required |

## Footnote Key

N/A–not applicable
DNR–did not report
[1] Provided for reference purposes; additional clearance may be required per *Code*
[2] Provided for reference purposes; size all conductors per *NEC*
[3] Optional fused subcombiners provide additional terminal and cable options
[4] Option to -35
[5] Stainless steel option
[6] At 240 Vac: start voltage = 320, MPPT = 320–600, max. dc current = 440 A
[7] 0.1 kW–10 kW, 1 kW default
[8] Two person lift
[9] Low-voltage tap option widens range to 295–500 V
[10] Low-voltage tap option widens range to 285–500 V
[11] For connection to MV transformer
[12] With external MV transformer
[13] Estimated
[14] With side facing disconnects (standard)
[15] With forward facing disconnect (option)
[16] Conduit entry bottom
[17] Conduit entry side
[18] Left side 47 with conduits, 6 without conduits

| Surge Protection | | Performance | | | | | Mechanical | | | Dimensions, Clearance & Conduit Entry | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Surge protection (standard) | Surge-protection device | Peak efficiency (%) | CEC-weighted efficiency (%) | CEC night tare loss (W) | Ambient temp. range (°F) | Elevation (ft.) | Cooling approach | Noise level with fans (dB) | Enclosure material & rating | Inverter dimensions H x W x D (in.) | Min. clearance dimensions H x W x D (in.)[1] | Min. clearance from door or access panel (in.)[1] | Approved conduit-entry zones |
| ac, dc | DEHN | 97.2 | 96 | 205 | 32–122 | 6,562 | forced air | < 75 dB (A) | IP 21, NEMA 1 | 110 x 87 x 29 | 122 x 87 x 29 | 39 | bottom |
| ac, dc | DEHN | 97.2 | 96 | 410 | 32–122 | 6,562 | forced air | < 78 dB (A) | IP 21, NEMA 1 | 2x 110 x 87 x 29 | 2x 122 x 87 x 29 | 39 | bottom |
| ac, dc | DEHN | 97.2 | 96 | 615 | 32–122 | 6,562 | forced air | < 81 dB (A) | IP 21, NEMA 1 | 3x 110 x 87 x 29 | 3x 122 x 87 x 29 | 39 | bottom |
| ac, dc | DEHN | 97.2 | 96 | 820 | 32–122 | 6,562 | forced air | < 84 dB (A) | IP 21, NEMA 1 | 4x 110 x 87 x 29 | 4x 122 x 87 x 29 | 39 | bottom |
| none | none | 97 | 95.5 \| 95.5 \| 96 | 2.76 \| 0.6 \| 8.46 | -13–113 | 9,000 | forced air | 45 dB (A) @ 1 m | inverters: powder-coated aluminum, NEMA 3R | 70.5 x 43.3 x 39 | 70.5 x 115.3 x 111 | 36 | back, bottom |
| none | none | 97.1 | 95.5 \| 96 \| 96 | 0.46 \| 0.6 \| 1.41 | -13–113 | 9,000 | forced air | 46 dB (A) @ 1 m | inverters: powder-coated aluminum, NEMA 3R | 70.5 x 43.3 x 39 | 70.5 x 115.3 x 111 | 36 | back, bottom |
| none | none | 96.5 | 96 | 1.01 \| 0.9 | -13–113 | 9,000 | forced air | 48 dB (A) @ 1 m | inverters: powder-coated aluminum, NEMA 3R | 70.5 x 43.3 x 39 | 70.5 x 115.3 x 111 | 36 | back, bottom |
| none | none | 97.5 | 97 | 69 | -13–122 | 13,000 | forced air | 60 dB (A) @ 10 m | zinc-plated & coated steel, NEMA 3R | 80 x 110 x 33 | 96 x 122 x 86,[16] 96 x 163 x 86[17] | 47 front[18] | bottom, left |
| none | none | 97.5 | 97 | 79.3 | -13–122 | 13,000 | forced air | 53 dB (A) @ 10 m | zinc-plated & coated steel, NEMA 3R | 80 x 140 x 37 | 96 x 152 x 90,[16] 96 x 193 x 90[17] | 47 front[18] | bottom, left |
| none | none | 98.5 | 97[12] | DNR | -13–122 | 13,000 | forced air | 59 dB (A) @ 10 m | zinc-plated & coated steel, NEMA 3R | 90 x 101 x 38 | 108 x 113 x 97,[16] 108 x 154 x 97[17] | 47 front[18] | bottom, left |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 95.8 | 94.0 \| 94.5 | 3 \| 10 | -13–122 | 8,000 | forced air | 66 dB @ 1 m | treated & polyester powder-coated steel, SS option | 26 x 34.5 x 13,[14] 26 x 46 x 13[15] | 30 x 47 x 49,[14] 30 x 106 x 49[15] | 36 | top, bottom, back, front |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 95.8 | 94.0 \| 94.5 | 3 \| 10 | -13–122 | 8,000 | forced air | 67 dB @ 1 m | treated & polyester powder-coated steel, SS option | 26 x 34.5 x 13,[14] 26 x 46 x 13[15] | 30 x 47 x 49,[14] 30 x 106 x 49[15] | 36 | top, bottom, back, front |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 95.5 \| 96.5 | 94.0 \| 95.5 | 5 \| 14 | -13–122 | 8,000 | forced air | 76 dB @ 1 m | treated & polyester powder-coated steel, SS option | 76 x 54 x 25,[14] 76 x 81 x 25[15] | 78 x 82 x 61,[14] 78 x 126 x 61[15] | 36 | top, bottom, back, front |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 96.0 \| 96.5 | 94.5 \| 95.5 | 5 \| 14 | -13–122 | 8,000 | forced air | 77 dB @ 1 m | treated & polyester powder-coated steel, SS option | 76 x 54 x 25,[14] 76 x 86 x 25[15] | 78 x 82 x 61,[14] 78 x 128 x 62[15] | 36 | top, bottom, back, front |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 96.0 \| 96.5 | 94.5 \| 95.5 | 5 \| 14 | -13–122 | 8,000 | forced air | 79 dB @ 1 m | treated & polyester powder-coated steel, SS option | 76 x 54 x 25,[14] 76 x 86 x 25[15] | 78 x 82 x 61,[14] 78 x 128 x 62[15] | 36 | top, bottom, back, front |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 96.5 \| 97.0 | 96 \| 96.5[13] | 18 \| 26 | -40–122 | 8,000 | forced air | 74 dB @ 1 m | treated & polyester powder-coated steel, SS option | 82 x 109 x 41 | 94 x 117 x 73 | 36 | bottom, back, left |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 96.6 \| 97.3 | 96 \| 97[13] | 18 \| 26 | -40–122 | 8,000 | forced air | 75 dB @ 1 m | treated & polyester powder-coated steel, SS option | 82 x 109 x 41 | 94 x 117 x 73 | 36 | bottom, back, left |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 96.6 \| 97.5 | 96 \| 97[13] | 18 \| 26 | -40–122 | 8,000 | forced air | 75 dB @ 1 m | treated & polyester powder-coated steel, SS option | 82 x 109 x 41 | 94 x 117 x 73 | 36 | bottom, back, left |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 96.8 \| 97.4 | 96 \| 97[13] | 18 \| 26 | -40–122 | 8,000 | forced air | 75 dB @ 1 m | treated & polyester powder-coated steel, SS option | 82 x 109 x 41 | 94 x 117 x 73 | 36 | bottom, back, left |
| ac, dc | MOVs & DIN rail-mounted surge arrestors | 96.6 \| 97.5 | 96 \| 97[13] | 18 \| 26 | -40–122 | 8,000 | forced air | 77 dB @ 1 m | treated & polyester powder-coated steel, SS option | 82 x 109 x 41 | 94 x 117 x 73 | 36 | bottom, back, left |

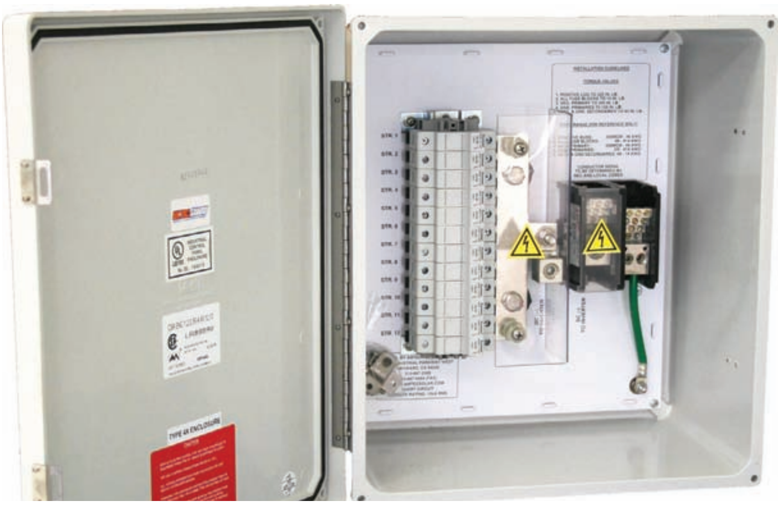
# 2010 Central Inverter Specifications Guide

| | | Transportation | | Termination Specifications[2] | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Manufacturer | Model | Lifting provisions | Weight (lbs.) | Number dc terminals[3] | Min. dc cable size (AWG or kcmil)[3] | Max. dc cable size (AWG or kcmil)[3] | dc terminal type[3] | Number ac terminals (per phase) | Min. ac cable size (AWG or kcmil) | Max. ac cable size (AWG or kcmil) | Number GEC terminals |
| Siemens Industry | SINVERT PVS351 UL | forklift | 6,614 | 3 | 600 | 700 | lug | 1 | 750 | 1,000 | 1 |
| Siemens Industry | SINVERT PVS701 UL | forklift | 2 x 6,614 | 6 | 600 | 700 | lug | 2 | 750 | 1,000 | 2 |
| Siemens Industry | SINVERT PVS1051 UL | forklift | 3 x 6,614 | 9 | 600 | 700 | lug | 3 | 750 | 1,000 | 3 |
| Siemens Industry | SINVERT PVS1401 UL | forklift | 4 x 6,614 | 12 | 600 | 700 | lug | 4 | 750 | 1,000 | 4 |
| SMA Solar Technology | ST 36 | forklift, eyebolts | 1,176 | 24 | 16 | 6 | lug | 1 | 14 | 350 | 1 |
| SMA Solar Technology | ST 42 | forklift, eyebolts | 1,176 | 24 | 16 | 6 | lug | 1 | 14 | 350 | 1 |
| SMA Solar Technology | ST 48 | forklift, eyebolts | 1,218 | 24 | 16 | 6 | lug | 1 | 14 | 350 | 1 |
| SMA Solar Technology | SC 250U | forklift | 4,200 | 4–12 | 2 | 300 | lug | 1, 2 | 600, 250 | 600 or 250 | 1 |
| SMA Solar Technology | SC 500U | forklift | 7,165 | 6–18 | 4/0 | 800 | lug | 2 | 400 | 400 | 1 |
| SMA Solar Technology | SC 500HE-US | forklift | 3,970 | 6–18 | 4/0 | 800 | lug | 5 | 600 | 600 | 1 |
| Solectria Renewables | PVI 13kW | forklift, minilift | 380 | 2 | 4 | 2/0 | lug | 1 | 6 \| 8 | 2 | 1 |
| Solectria Renewables | PVI 15kW | forklift, minilift | 400 | 2 | 4 | 2/0 | lug | 1 | 6 \| 8 | 2 | 1 |
| Solectria Renewables | PVI 60kW | forklift, eyebolts | 1,626 | 2–4 | 1/0 | 750 | lug | 1 \| 2 | 2 \| 1/0 | 750 \| 250 | 2 |
| Solectria Renewables | PVI 82kW | forklift, eyebolts | 1,782 | 2–4 | 1/0 | 750 | lug | 1 \| 2 | 2 \| 1/0 | 750 \| 250 | 2 |
| Solectria Renewables | PVI 95kW | forklift, eyebolts | 1,846 | 2–4 | 1/0 | 750 | lug | 1 \| 2 | 1 \| 1/0 | 750 \| 250 | 2 |
| Solectria Renewables | SGI 225 | forklift, eyebolts | 5,170 | 6–24 | 6 | 1/0 | lug | 3 \| 2 | 2/0 \| 3/0 | 400 \| 500 | 1 |
| Solectria Renewables | SGI 250 | forklift, eyebolts | 5,170 | 6–24 | 6 | 1/0 | lug | 4 \| 2 | DNR \| 3/0 | DNR \| 500 | 1 |
| Solectria Renewables | SGI 266 | forklift, eyebolts | 5,170 | 6–24 | 6 | 1/0 | lug | 4 \| 2 | DNR \| 3/0 | DNR \| 500 | 1 |
| Solectria Renewables | SGI 300 | forklift, eyebolts | 5,650 | 6–24 | 6 | 1/0 | lug | 4 \| 2 | DNR \| 3/0 | DNR \| 500 | 1 |
| Solectria Renewables | SGI 500 | forklift, eyebolts | 6,980 | 8–32 | 2 | 350 | lug | 4 \| 3 | DNR \| 2/0 | DNR \| 400 | 1 |

## Footnote Key

N/A–not applicable
DNR–did not report
[1] Provided for reference purposes; additional clearance may be required per *Code*
[2] Provided for reference purposes; size all conductors per *NEC*
[3] Optional fused subcombiners provide additional terminal and cable options
[4] Option to -35
[5] Stainless steel option
[6] At 240 Vac: start voltage = 320, MPPT = 320–600, max. dc current = 440 A
[7] 0.1 kW–10 kW, 1 kW default
[8] Two person lift
[9] Low-voltage tap option widens range to 295–500 V
[10] Low-voltage tap option widens range to 285–500 V
[11] For connection to MV transformer
[12] With external MV transformer
[13] Estimated
[14] With side facing disconnects (standard)
[15] With forward facing disconnect (option)
[16] Conduit entry bottom
[17] Conduit entry side
[18] Left side 47 with conduits, 6 without conduits

| | | Disconnects & Subcombiners | | | Listing | | Data | Warranty | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Min. GEC cable size (AWG or kcmil) | Max. GEC cable size (AWG or kcmil) | dc disconnect (load-break rated?) | ac disconnect (load-break rated?) | Integral fused subcombiner[3] | Listing agency | Safety listings and certifications | Type of databus | Standard (yr.) | Extended (yr.) | PM or service contract option |
| 2 | 2 | standard (no) | standard (yes) | standard: 3 x 400 A | UL, TUV | UL 1741, CSA 107.1-01, IEEE 1547, UL1998 | RS-232, RS-422, RS-485, Ethernet | 5 | 20 | yes |
| 2 | 2 | standard (no) | standard (yes) | standard: 6 x 400 A | UL, TUV | UL 1741, CSA 107.1-01, IEEE 1547, UL1998 | RS-232, RS-422, RS-485, Ethernet | 5 | 20 | yes |
| 2 | 2 | standard (no) | standard (yes) | standard: 9 x 400 A | UL, TUV | UL 1741, CSA 107.1-01, IEEE 1547, UL1998 | RS-232, RS-422, RS-485, Ethernet | 5 | 20 | yes |
| 2 | 2 | standard (no) | standard (yes) | standard: 12 x 400 A | UL, TUV | UL 1741, CSA 107.1-01, IEEE 1547, UL1998 | RS-232, RS-422, RS-485, Ethernet | 5 | 20 | yes |
| 2 | 2/0 | standard 6x (yes) | standard 6x (yes) | standard: 24 x 15 A | UL | UL 1741 US & Canada, FCC Class B | inverter: RS-485 or Bluetooth; datalogger: Ethernet | 10 | 15, 20 | no |
| 2 | 2/0 | standard 6x (yes) | standard 6x (yes) | standard: 24 x 15 A | UL | UL 1741 US & Canada, FCC Class B | inverter: RS-485 or Bluetooth; datalogger: Ethernet | 10 | 15, 20 | no |
| 2 | 2/0 | standard 6x (yes) | standard 6x (yes) | standard: 24 x 15 A | UL | UL 1741 US & Canada, FCC Class B | inverter: RS-485 or Bluetooth; datalogger: Ethernet | 10 | 15, 20 | no |
| 3/0 | 600 | no (no) | no (no) | standard: 4 x 350 A, option: 6 x 250 A | UL | UL 1741 US & Canada, FCC Class B | inverter: RS-485; datalogger: Modbus, Ethernet | 5 | 6–20 | yes |
| 3/0 | 600 | no (no) | no (no) | standard: 6 x 450 A, 7 x 400 A, 8 x 350 A, 9 x 300 A | UL | UL 1741 US & Canada, FCC Class B | inverter: RS-485; datalogger: Modbus, Ethernet | 5 | 6–20 | yes |
| 3/0 | 600 | no (no) | no (no) | standard: 6 x 450 A, 7 x 400 A, 8 x 350 A, 9 x 300 A | UL | UL 1741 US & Canada, FCC Class B | inverter: RS-485; datalogger: Modbus, Ethernet | 5 | 6–20 | yes |
| 8 | 4 | standard & external (yes) | standard & external (yes) | option: 5–7 x 8–15 A | ETL | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | 10, 15 | yes |
| 8 | 4 | standard & external (yes) | standard & external (yes) | option: 5–7 x 8–15 A | ETL | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | 10, 15 | yes |
| 6 | 250 | standard & external (yes) | standard & external (yes) | option: 2–8 x 40–275 A | ETL | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | 10, 15, 20 | yes |
| 6 | 250 | standard & external (yes) | standard & external (yes) | option: 2–8 x 40–275 A | ETL | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | 10, 15, 20 | yes |
| 6 | 250 | standard & external (yes) | standard & external (yes) | option: 2–8 x 40–275 A | ETL | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | 10, 15, 20 | yes |
| 1/0 | 750 | standard & external (yes) | standard & internal (yes) | required option: 6–24 x 70–350 A | ETL | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | 10, 15, 20 | yes |
| 1/0 | 750 | standard & external (yes) | standard & internal (yes) | required option: 6–24 x 70–350 A | ETL | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | 10, 15, 20 | yes |
| 1/0 | 750 | standard & external (yes) | standard & internal (yes) | required option: 6–24 x 70–350 A | ETL | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | 10, 15, 20 | yes |
| 1/0 | 750 | standard & external (yes) | standard & internal (yes) | required option: 6–24 x 70–350 A | ETL | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | 10, 15, 20 | yes |
| 1/0 | 750 | standard & external (yes) | standard & internal (yes) | required option: 8–32 x 70–400 A | ETL | UL 1741, CSA 107.1-01, IEEE 1547 | Modbus RTU | 5 | 10, 15, 20 | yes |



Courtesy AMtec Solar

**1,000 Vdc rated BOS** Though there may be a cost penalty in purchasing 1,000 Vdc rated combiners, disconnects, fuses and cables, products like this AMtec Prominence 12 String combiner box are increasingly available in North America for behind-the-fence applications.

1,000 Vdc rated BOS equipment—including cables, combiner boxes, switches, fuses or breakers—the higher-voltage design typically provides enough savings to justify these extra costs.

**Ungrounded systems.** Conventional practice in the US is to ground dc systems. This is based on 110 years of history and code development for electrical systems in general. The evolution of European electrical practice over the same time span resulted in a standard of operating ungrounded, or floating, dc systems. This does not mean the exposed metal equipment is installed without equipment grounds, but rather that the dc circuit itself is not bonded to ground at the inverter, as is the case with grounded systems. As PV and *NEC* guru John Wiles acknowledges, both approaches—if designed properly—can result in high-quality, safe electrical installations. While the *NEC* does allow for ungrounded systems, as described in Article 690.35, so far there is little in the way of available NRTL-listed equipment to support such designs.

In practice, the differences between grounded and ungrounded PV systems relate to switching, overcurrent protection and fault detection. With grounded systems, the grounded conductor cannot be switched or fused and should be disconnected from ground only in the event of a ground fault. With floating systems, both poles must be switched, and best practice is to fuse both the negative and positive circuits in combiner boxes and switches. This increases the fuse and switch count compared to a similarly rated grounded system. Cables also need to have enhanced insulation ratings because of the lack of ground reference. PV Cable (generally cross-listed as USE-2 or RHW-2) for floating systems in the US should meet UL 4703, which dictates the appropriate insulation thickness and requires 720 hours of UV exposure testing to achieve the Sunlight Resistant designation.

**Fault protection.** A significant advantage to the floating system is the more benign impact of ground faults and a greater ability to protect against dangerous ground-fault currents. With a grounded system, a single short to ground in the ungrounded circuit anywhere in the array typically takes the form of an arcing current. The fault current is generally sufficient to trip the ground-fault protection in the inverter, but high-impedance faults in low-sunlight conditions can go undetected. Furthermore, shorts between grounded string conductors and ground can go undetected indefinitely. If there is a subsequent fault on an ungrounded conductor, the inverter's ground-fault protection does not interrupt the circulating current between the two faults. One high-profile PV fire has already occurred as a result of this particular phenomenon, and it could happen again even in well-designed *Code*-compliant systems.

With a floating system, however, ground faults are detected by measuring the impedance between each pole and ground, and can be detected day or night—independent of the amount of sunlight. A single ground fault is easily detected and creates no significant arc or fault current. The system can be shut down upon detection and the faulted conductor repaired. This approach greatly reduces the risks in first-fault scenarios. Arrays that need functional grounding to ensure proper performance, such as SunPower modules and some thin-film technologies, can largely achieve the protection benefits of floating systems by using a high-ohmic connection to ground. These maintain the ground reference needed while limiting first-fault currents to levels far more benign than in hard-grounded systems.

**Indoor-rated versus outdoor-rated equipment.** Another difference between the central inverters evolving on the two sides of the Atlantic is their enclosures. US inverters have invariably been designed for outdoor installation, eliminating the need for additional protection against the environment. Central inverters in Europe, however, have been designed with indoor-rated enclosures, meaning an additional container or housing is required for open-field PV installations using these products.

This trend, which extends well beyond PV technology, is based on the presumption that electrical equipment containing power semiconductors, digital signal processors, capacitors, fans and other heat-sensitive components holds up more reliably over the long-term in a controlled indoor environment. Outdoor-rated equipment, however, must reliably withstand years of exposure to UV, water, snow, wind and dust. Another advantage of containerized systems is


Courtesy Schneider Electric

**Ventilation details** Nineteen 1 MW PV Boxes from Schneider Electric are deployed at enXco's 23 MWdc Arnprior Solar Project in Ontario, Canada. This photo shows the louvered steel detail surrounding the MV transformer and the outlet for the exhaust fan that serves the inverter compartment.

the ability to house peripheral equipment—such as SCADA systems, low-voltage panels, switchgear and so on—without individual outdoor-rated enclosures. In addition, operators performing O&M tasks prefer to work inside, particularly in locations where rain and snow is routine.

Locating equipment outdoors does have its advantages, however. Equipment pads are generally less expensive than containerized systems, although many integrators may still prefer to put shelters or shade structures over the pad for convenience during O&M and to provide some UV and water protection. Additional fans or heaters are not required to regulate temperatures, as the inverters are simply exposed to ambient conditions. Finally, permitting is simplified, since walk-in containers have additional requirements and costs for personnel protection.

Several international inverter suppliers, including Satcon, SMA and Xantrex, offer both indoor- and outdoor-rated units to meet integrator preferences. If not properly designed, both indoor and outdoor approaches can result in reduced inverter lifetime due to heat. With outdoor systems, additional heat from solar gain, reduced airflow caused by dirty filters, and defective or aged enclosures impact equipment lifetime. With indoor units, improper ventilation at the container level can result in an excessive delta between indoor and outdoor temperatures, potentially leading to overtemperature conditions for the inverter.

## UTILITY CONTROL REQUIREMENTS

As PV power plants get larger, utilities expect them to abide by the same operating and ancillary service requirements as those of large-scale wind and conventional fuel-based technologies.

Central inverters today, listed to UL 1741 and complying with IEEE 1547, are specifically required to operate at unity power factor—meaning voltage and current are perfectly in phase with a power factor of 1.0—and to shut down and go off line in the event of a utility disturbance. This is to ensure that their presence does not hinder the effective operation of the utility's own voltage regulation and protective equipment. This model has served the PV industry tremendously well for the past decade by standardizing the protection measures and simplifying the utility interconnection review and acceptance process for residential and commercial systems.

Larger plants and higher penetrations of PV generation, however, can cause more harm than good if they cannot provide voltage regulation support, or if they disconnect during a utility disturbance when the utility needs all the available generation to minimize the impact. Power plant control requirements vary depending on the system size, governing utility, transmission system operator and local system needs. Meeting these requirements is generally not significantly challenging for inverter manufacturers since they involve mostly software changes and minor hardware changes. Generalized requirements have been developed for PV plants in Europe, notably Germany, France and Spain. In the US, the FERC 661-A standard for wind plants has been applied to PV plants, and generalized requirements are expected to be included in the upcoming development of IEEE 1547.8. Inverter capabilities under these requirements include volt-amperes-reactive (VAR) control, low-voltage ride through (LVRT) and dynamic control.

**VAR control.** The plant must be able to supply or absorb reactive power as needed by the utility, primarily for system voltage control. Most standards to date require power factor control at the POI from 0.95 leading to 0.95 lagging. Inverters are inherently capable of providing reactive power support and can supply VARs even when no real power is being produced by the array. At face value it seems like a win-win situation for inverters to use their inherent VAR capabilities in support of the grid. However, a cost trade-off evaluation is warranted on a case-by-case basis. First, the total inverter capacity must be rated for the combined real and reactive power demand from the utility, or the inverters must fold back on the real power production to maintain the required power factor or VAR. Second, the reactive power demands of the collection system and MV transformers mean that inverters must have a wider range of power factor capability than is required at the utility POI. Finally, the expense of the additional inverter capacity and related control system may exceed the cost of more traditional VAR control measures, such as switched capacitors or static VAR compensators, which are located at the POI.

**Low-voltage ride through.** The plant must be able to continue operation and stay on line in the event of short-duration disturbances or interruptions. LVRT requirements specify operating time or duration curves that dictate how long the inverter must stay on at different magnitudes of low voltage. The FERC 661-A standard, for example, requires ride-through capability for nine cycles down to zero volts at the POI. Unlike traditional anti-islanding, which exacerbates grid-voltage dip, LVRT helps to improve system stability.

**Dynamic control.** The plant must be in communication with the utility system at all times and under the command and control of its operators. Dynamic control allows operators to limit real power on demand by controlling its ramp rate or curtailing its production. It also allows operators to control other operational set points, such as over- or under-voltage trip settings. In short, it allows a PV power plant to operate like a traditional power plant.

**Utility controllable** Many of the current generation central inverter offerings, like this 500 kW Smart Grid Inverter from Solectria, are able to meet utility requirements for VAR control, low-voltage ride through, and dynamic command and control.

Courtesy Solectria Renewables

## ADDITIONAL DESIGN CONSIDERATIONS

In their *SolarPro* article "Next Generation Central Inverters" (Dec/Jan 2009), Tobin Booth and Danny Lee detail comprehensive design considerations for engineers and integrators working with central inverters. Readers CONTINUED ON PAGE 62


The SMARTGRID 500KW inverter incorporates all of the ideas and intelligence customers and utility engineers alike have long been asking for: VAR support to minimize transmission losses, low voltage ride-through capability, standard Ethernet, remote command and control for future smart grid capabilities. With Solectria Renewables' premium efficiency, serviceability and lowest array shading setback in the industry, the SMARTGRID 500 will undoubtedly become a favorite of integrators worldwide.

Learn more about our US manufactured PV inverters at www.solren.com.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Grid-Tied inverters, kW-MW    inverters@solren.com    www.solren.com    Boston - 978.683.9700 can refer to this technical content for insights on a variety of topics, including designing and constructing inverter pads, moving and transporting inverters, managing large conduits and conductors and specifying dc service disconnects and fused subcombiners. Here I cover a few additional design considerations, including bipolar inverters, two-stage inverters and inverter loading.

Since the Booth and Lee article was written, the relevance of bipolar and two-stage inverters has changed. Market penetration for bipolar AE Solaron inverters, for example, has increased, and Satcon only recently released its two-stage Solstice inverter platform. Meanwhile, inverter loading is dynamic, responding to market conditions and other factors. Recent trends in module pricing have resulted in increasingly higher PV-to-inverter sizing ratios. That being the case, one question that invariably rises is: How much dc loading of an inverter is too much?"

**Bipolar inverters.** Though not a new concept or topology, bipolar inverters are resurgent with the success of the AE Solaron inverter platform. The AE Solaron incorporates a unique bipolar design that allows for transformerless operation with a standard 480 Vac low voltage output. Two separate 600 Vdc arrays feed the inverter: One is referenced positive and the other is referenced negative with respect to ground. The inverter, therefore, operates with a 1,200 Vdc maximum bus, even though equipment in the field does not exceed 600 Vdc relative to ground.

Voltage ratings for cables, combiner boxes and switches do not have to exceed 600 Vdc, as long as the circuits from the positive and negative arrays are run in separate conduits and enclosures up to the interface with the inverter. The neutral cables of both arrays are referenced to ground and should be treated like any other grounded, current-carrying conductor. When the inverters are off, these neutral circuits are hard-connected to ground. During operation, the neutral circuits are referenced via the inverter switching to the ac neutral, which is grounded at the ac service entrance or panel.

There is some debate about how well this approach meets the letter and intent of *NEC* Article 690.35, but AE maintains that grounding via the ac neutral is a well-accepted practice. According to Jeff Roesch, an electrical engineer for AE, "The dc input to the inverter is a 4-wire bipolar configuration with two wires for the positive array and two wires for the negative array. When the unit is in the off state, the neutral wire from each array is tied to ground through 3 A fuses, which complies with Article 690.5(A) of the *NEC.* When the inverter is in the on state, the arrays are referenced to the grounded wye of the transformer through the inverter. This is in accordance with Article 690.41(A), which allows other system grounding methods 'that accomplish equivalent system protection in accordance with 250.4(A).' Our equivalent system protection has been reviewed and accepted by CSA, the Nationally Recognized Testing Laboratory we work with."

**AE Solaron bipolar inverter** Using bipolar arrays allows AE inverters, like this Solaron 500 kW at Colorado State University, to operate with a 1,200 Vdc maximum bus, even though the individual arrays never exceed +600 Vdc or -600 Vdc relative to ground.


Courtesy Advanced Energy

**Two-stage inverters.** With the Satcon Solstice—the first two-stage central inverter solution on the market—the array MPPT is distributed at the string level along with dc-to-dc conversion in specialized 25 kW subcombiner boxes, which also provide string-level monitoring. These Solstice subcombiners are configured for use with fixed-voltage Solstice inverters rated at 100 or 500 kW for UL models. Solstice subcombiners provide independent MPP tracking at the string level and convert the string voltage to a higher, fixed nominal voltage input into the inverter—575 Vdc for UL applications or 725 Vdc for behind-the-fence projects. The higher regulated voltage means lower cable ampacity requirements CONTINUED ON PAGE 64

and greater inverter efficiency. Independent MPP trackers ensure increased energy harvest, particularly in systems where uneven shading or other causes of module mismatch may otherwise reduce system performance.

The two-stage conversion process results in additional conversion losses relative to a single-stage inverter at peak efficiency, however. Increased overall performance is dependent on the ability to capture more energy from individual MPP trackers and on the optimized fixed-voltage inverter efficiency across all operating conditions.

**Inverter loading.** Inverter manufacturers sometimes include a maximum dc power rating on technical data sheets, such as 115 kWp for a 100 kW inverter. Historically this rating is less about protecting the inverter than it is a guideline to ensure that energy from the array is never limited, or clipped, by the inverter's maximum capacity. Typically, arrays in the US have been designed with ratios of 100% to 120% of inverter rating. PV system economics prior to the dramatic module price decreases in 2009 generally justified inverter clipping only if the resultant energy loss was well under 1% of the annual energy production. However, with module prices lower, the lost energy cost is less pronounced relative to purchasing and maintaining a larger fleet of inverters. Many integrators are finding that optimal array sizes may be 130% to 140% of inverter capacity. (See "Optimal PV-to-Inverter Sizing Ratio," April/May 2010, *SolarPro* magazine.)

Is it really okay to operate inverters that are this heavily loaded? Inverters can protect themselves from overpower or overcurrent conditions by moving off the MPP voltage of the array. But heat has an inverse relationship to inverter lifetime, and heavily loaded inverters (especially those connected to single- or dual-axis trackers) spend far more time operating at their capacity and thus at elevated temperatures. That being the case, it is not unreasonable to suspect that inverter component replacement times may be shortened with heavier loading. Stability problems might also occur if a combination of high inverter loading and high irradiance variability—caused by cloud enhancement, for example—causes the inverter to move quickly on the steep edge of the IV curve.

When interviewed, suppliers express no concern about the stability issue, noting that the MPPT response times are sufficiently fast to handle such transients. However, their responses vary somewhat regarding the maximum recommended inverter loading. For example, Marc Johnson, senior applications engineer for PV Powered, notes that the company's inverters are designed to have a 20-year lifetime, which sets a higher bar than simply offering a 20-year warranty based on a risk/failure analysis. This means that the inverters are designed to never operate above their nameplate rating. "While the maximum voltage must be strictly adhered to, there is no inverter maximum power limit," Johnson explains. "The inverter will limit its own power output to the nameplate rating." PV Powered does recommend, however, that customers contact them if they are considering loading the inverter above 130% of its ac nameplate rating, based on the array's STC rating. The company can help clients evaluate the pros and cons of their specific designs.

Satcon's senior director of product management, Allan Gregg, is not concerned about array oversizing. He confirms that the company's inverters can also protect themselves against overcapacity and encourages designers to install arrays sized according to best overall plant economics. "With the long-duration testing at elevated temperatures that Satcon's inverters endure," Gregg says, "reduced lifetimes are not an issue."

Meanwhile, Verena Arps, technical sales support manager for SMA America, says that a maximum sizing ratio of 120% is the standard recommendation for the company's UL-listed inverters. "We have seen integrators seeking to size their arrays even larger," says Arps. "Although this is possible, those projects must be assessed on an individual basis. As with any electronic system, running at maximum output places more stress on its components, making quality construction and diligent maintenance paramount."

While each of these experts generally downplays concerns about decreased component life due to heavy inverter loading, the maximum recommended PV-to-inverter sizing ratio is nevertheless product- and project-specific. This emphasizes the importance of consulting with the manufacturer's applications engineers when evaluating design decisions. Doing so will increase your familiarity and competence with central inverter products, as well as your confidence in the systems that you design or install.

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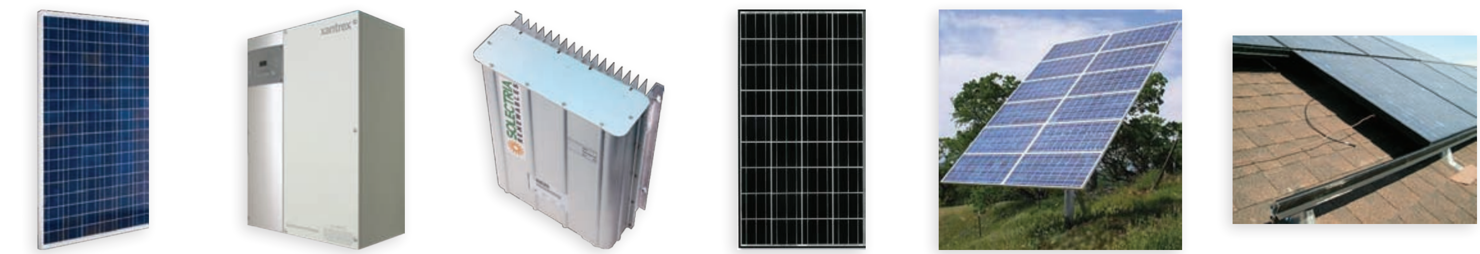

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# Array Voltage

Source-circuit configuration is arguably the most important aspect of PV system design. The electrical and mechanical characteristics of a PV array follow from this fundamental design decision, which has a bearing on both labor and material costs. In addition, source-circuit configuration impacts system performance, in some cases negatively. Low dc array voltage, for example, is a common cause of substandard performance that occurs when open-circuit or operating voltages for an array persistently fail to meet minimum inverter dc input voltage thresholds over time. In this situation, the system design does not take into account the cumulative effects of a variety of real-world circumstances, including high ac grid voltage, array degradation, module-to-module voltage tolerance and high ambient temperatures. Fortunately, low dc array voltage is avoidable.

In this article, I detail array design best practices for determining the maximum number of modules in a source circuit. My approach is slightly less conservative than the industry standard and is supported by changes to the *National Electrical Code* that are introduced in the 2011 cycle. I also present recommendations for determining the minimum number of modules per source circuit. While these may be more conservative than current design standards, my opinions are based on years of experience. They are not influenced by the desire to sell more or less of any specific product but rather by the general desire to propagate well-designed PV systems that perform optimally for decades.

## CONSIDER THE SOURCE

Interestingly enough, over the past decade inverter manufacturers have been the primary source of education regarding array design and source-circuit sizing. With all due respect, these companies usually have expertise in power electronics and not necessarily in PV array design. However, since the advent of the first string-sizing program—which was developed by John Berdner while he was the president of SMA America—it has become the industry standard for inverter manufacturers to provide PV array configuration advice.

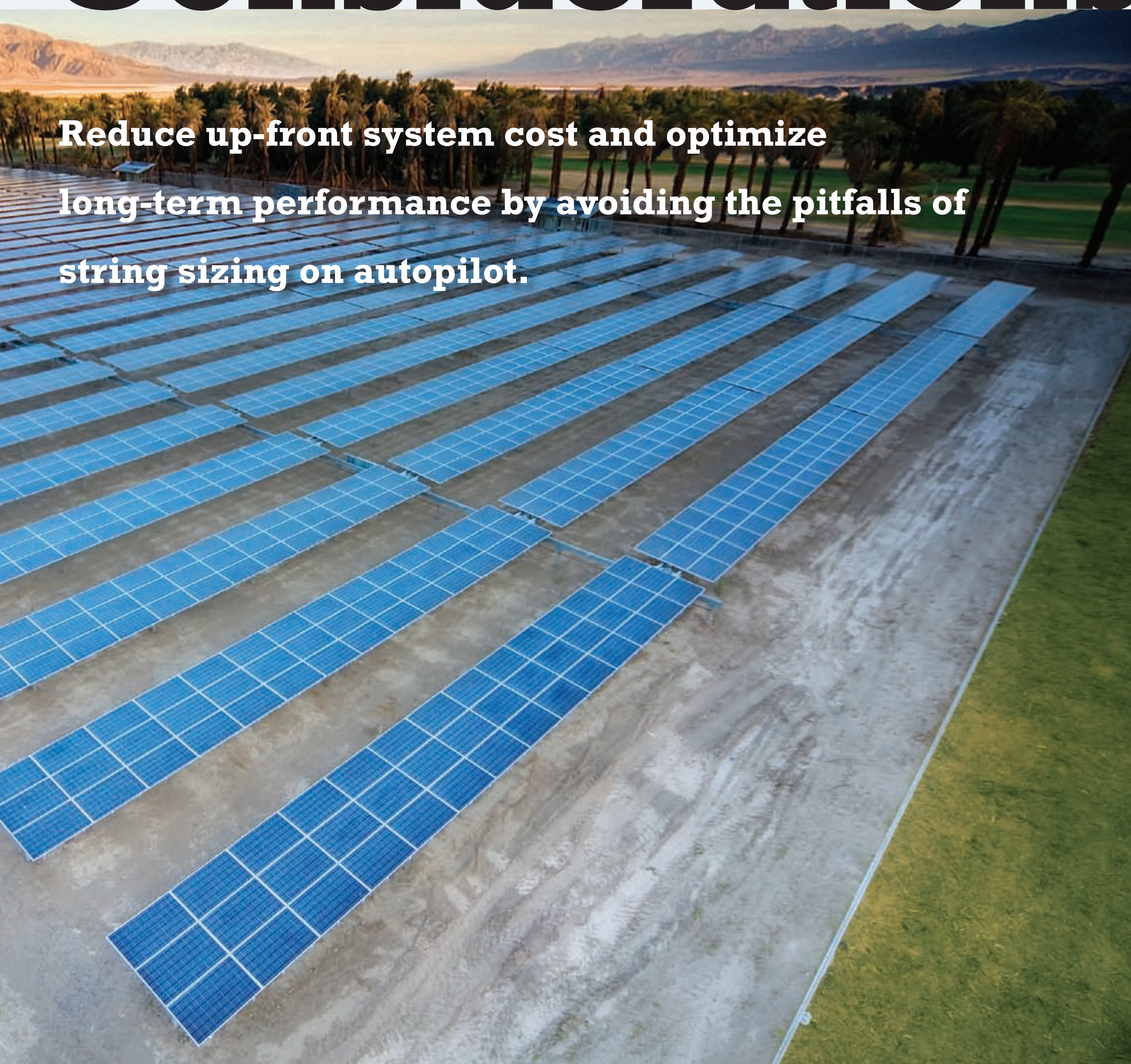
The main drawback to having inverter manufacturers dictate array design is that they have a conflict of interest. Manufacturers want their products to be used as often as possible, and this is facilitated in part by allowing the maximum number of module configurations. In addition, although most manufacturers have stern warnings about exceeding the maximum inverter input voltage, they generally have little to say about circumstances where there is too little voltage for the inverter to fully operate the PV array.

This skewed perspective informs both the string-sizing tools and the training materials that inverter manufacturers develop. The upshot is that inverters in the field seldom have a problem with high array voltage but routinely have problems with low array voltage. While low array voltage will not damage the inverter, it will compromise system performance.

By Bill Brooks, PE

# Considerations

**Reduce up-front system cost and optimize long-term performance by avoiding the pitfalls of string sizing on autopilot.**



Courtesy SPG Solar and Xanterra Parks & Resorts

If the inverter cannot operate the array at its MPP, for example, then power production and energy harvest suffer. Problems can also result from open-circuit voltage being too low. On hot days, an array's Voc can pass below the restart voltage of the inverter. The consequence is that if the inverter shuts down in the middle of the day due to a utility disturbance, it will not restart until the late afternoon when the Voc increases. This can reduce the system's operating availability by several percentage points annually if utility disturbances are common in the summer, such as when utilities switch in distribution capacitors around noon on hot days to accommodate high air conditioning loads. To design a PV array that is well-matched to an inverter's operating window, system designers need to pay attention to the low end of the inverter operating voltage range, as well as to the maximum voltage allowed.

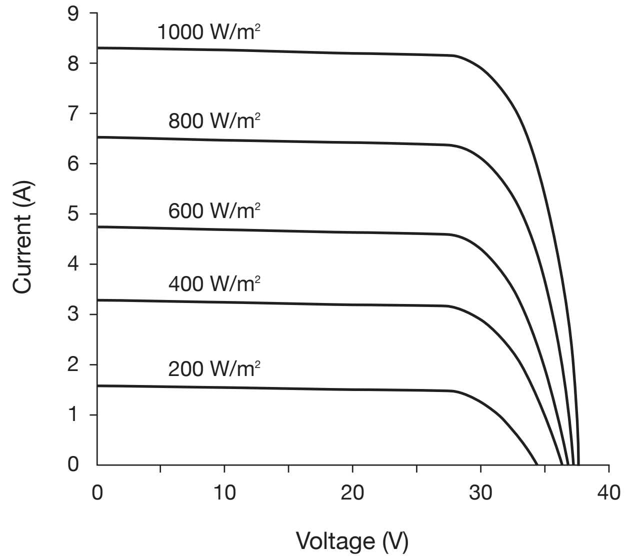



**Figure 1** This representative module I-V curve is based on published curves for Yingli polycrystalline modules. It assumes a 25°C cell temperature and illustrates how open-circuit voltage responds to decreasing irradiance.

## HIGH DC VOLTAGE

The maximum dc voltage for an inverter is clearly stated on the product specification sheet, installation manual or in tables, such as the one on pages 46–57. While relevant UL standards and *NEC* requirements certainly apply, the maximum voltage is generally set by the input capacitors and the ratings of the transistors in the inverter, so it is a constant rather than a variable limit.

Because it is possible to create overvoltage in an inverter by putting too many modules in series, some manufacturers keep the maximum dc input voltage in nonvolatile memory for warranty purposes. This allows the manufacturer's service technicians to verify the maximum dc voltage input to any inverter that is returned from the field under warranty. If the inverter was exposed to overvoltage conditions, then the manufacturer may choose not to provide a free replacement inverter. Historically, the most common cause of overvoltage is putting two source circuits in series rather than in parallel. This is a relatively easy mistake to make, especially in a small system with only two source circuits. Failure to properly account for low ambient temperatures is another potential cause of inverter overvoltage.

Some inverter manufacturers have claimed in their trainings that a 600 Vdc inverter will spontaneously combust if the array reaches 601 Vdc. While the inverter warranty may be voided if the array goes above the published maximum voltage, it is inconceivable that the capacitor or transistor tolerances are tight enough for the devices to operate well at 600 Vdc and explode at 601 Vdc. If that were true, inverters would also explode at 580 Vdc and they (usually) do not—at least not because of component tolerance.

**Low temperature calculation.** Most inverter manufacturers recommend using the site's record low temperature to determine the maximum number of modules per source circuit. While the record low temperature is easily attainable (see "Low Design Temperature," p. 72), it is also overly conservative for maximum voltage calculations. The record low temperature is usually too conservative for design calculations because temperature is only one of two major factors that impact array open-circuit voltage. The other major factor is irradiance. As an example, look at the set of I-V curves in Figure 1, which assumes constant cell temperature and variable irradiance, and notice where the I-V curves intersect the horizontal axis. As irradiance decreases, so does open-circuit voltage.

The *NEC,* however, uses temperature only to determine maximum system voltage. The criterion for determining the maximum PV system voltage, according to Article 690.7(A), is to correct the source circuit open-circuit voltage for the "lowest expected ambient temperature." Prior to the 2011 cycle, the *NEC* did not define the term *lowest expected ambient temperature*. However, the 2011 *NEC* will define it in an Informational Note (formerly known as a Fine Print Note) as follows: "One source for statistically valid, lowest expected ambient temperature design data for various locations is the Extreme Annual Mean Minimum Design Dry Bulb Temperature found in the American Society of Heating, Refrigeration, and Air Conditioning Engineers' *ASHRAE Handbook—Fundamentals.* These temperature data can be used to calculate maximum voltage using the manufacturer's temperature coefficients relative to the rating temperature of 25°C."

An Informational Note is not a *Code* requirement and cannot be interpreted as such. System CONTINUED ON PAGE 72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designers can use any authoritative source of data for the lowest expected ambient temperature. However, this Note is intended to help the designer and the AHJ focus on the most appropriate data for balanced array design. Since many system designers may not have ready access to the *ASHRAE Handbook,* the Extreme Annual Mean Minimum Design Dry Bulb Temperature data—hereafter referred to as the ASHRAE low design temperature data—is included in Appendix E of the *Expedited Permit Process for PV Systems* document that I wrote for the Solar America Board for Codes and Standards (Solar ABCs). This document is readily available on the SolarABCs website (see Resources) and includes data for more than 650 cities in the US.

When using string-sizing programs, the simple rule I recommend is to eliminate the lowest voltage option—the source circuit with the least number of modules in series.

Some may ask why ASHRAE data is better to use than the record low temperature. One reason is that using the record low temperature sometimes excludes acceptable source-circuit configurations that may in fact be preferred over shorter source circuits. (This is illustrated in "Case Study: Example dc Voltage Calculations," p. 75.) In addition, the extra margin of safety that the record low temperature design provides is often statistically insignificant when compared to the ASHRAE design.

System designers must consider three important issues when determining an appropriate design temperature. First, statistically, the record low temperature may never occur again. Second, lower irradiance conditions in winter make it even less likely that peak irradiance (1,000 W/m$^2$) will accompany the record low temperature, which is a necessary coincidence to achieve the calculated maximum voltage based on temperature. Third, to achieve in the field the maximum voltage that is possible on paper, the PV array must be in a condition that is as good as new. The modules cannot be soiled, mismatched or degraded; the maximum voltage for each of the installed modules must equal its published rating. The statistical likelihood of these conditions occurring at the same time is low.

The ASHRAE data provide statistically derived expected low temperatures. Although ASHRAE processes National Weather Service data for use by engineers sizing heating and cooling equipment, the data are also relevant to many other fields, including the electrical industry. The ASHRAE low design temperature data is derived by averaging the annual low temperature for every year on record. The result is a low temperature that has a 50% chance of occurring once a year at a specific location. Statistically, 50% of the years that a PV system is in service, the low for the year will be colder than this value—and for the other 50%, the low will never reach this value.

This does not mean that there is a 50:50 chance that the maximum voltage to the inverter will be exceeded in a given year. Remember that peak irradiance must CONTINUED ON PAGE 74

## Low Design Temperature

To find the record low temperature for any location in the US, go to Weather.com's Monthly Climatology web page at the following URL and specify the desired zip code: weather.com/weather/climatology/monthly/*zipcode.*

For design purposes, however, a location's record low temperature is very conservative, generally lower than the minimum expected ambient temperature at peak irradiance. The Extreme Annual Mean Minimum Design Dry Bulb Temperature data published by ASHRAE generally provide better low temperature design data in terms of statistical validity. These data are included in Appendix E of the *Expedited Permit Process for PV Systems,* which is available at the website for the Solar America Board for Codes and Standards.

One note of caution, however: All generalizations have exceptions. For example, a steeply tilted PV array in a high-altitude location subjected to snow reflectance may experience extreme open-circuit voltage conditions that even record low temperature design calculations will underestimate.

Courtesy Steve Proehl

**Proceed with caution** While the Extreme Annual Mean Minimum Design Dry Bulb Temperature data published by ASHRAE are generally statistically valid for maximum array Voc calculations, more conservative data may be required for PV arrays in higher-altitude locations.

accompany this temperature, and the modules must perform as if they were new and perfectly matched. Ultimately, engineering design involves a series of decisions based on the likelihood of an occurrence and the consequences should the worst case happen. Good system engineering balances valid concerns to develop a design that keeps all the equipment operating properly within acceptable limits. Using the record low temperature does not eliminate the statistical possibility of exceeding an inverter's maximum input voltage; it simply lowers the possibility relative to a higher temperature. I recommend using the ASHRAE low design temperature data unless there is a specific need for more conservative design data.

## LOW DC VOLTAGE

Inverter specification sheets seem simple enough to use, but some knowledge of how inverters work is required to interpret them. For example, in contrast to an inverter's published high dc voltage limit, the low dc voltage limit for most inverters is a variable that changes in response to the grid voltage. In addition, the voltage that an array is capable of, given specific environmental conditions like irradiance and cell temperature, diminishes over time. Designers must also account for the effects of module voltage tolerance when performing acceptable low dc voltage calculations. Many of the most egregious PV source-circuit design mistakes are due to a failure to account for these combined factors; these designs result in array voltages that are too low for the inverter.

**High ac grid voltage.** While a manufacturer might state that the low dc voltage for its inverter is 330 Vdc, this is usually the lowest acceptable dc input voltage at the nominal grid voltage. For residential systems, the nominal single-phase voltage is 240 Vac; for larger systems, the nominal 3-phase voltage might be 208, 240 or 480 Vac. As the ac voltage varies above nominal, the minimum dc input voltage rises as well.

If the ac voltage rises 5%, which is possible on hot summer afternoons, the minimum dc voltage also rises 5%. Therefore, an inverter with a minimum voltage rating of 330 Vdc has a minimum voltage of 347 Vdc under those 5% higher ac voltage conditions. This condition often occurs at precisely the time when the array dc voltage is at its lowest level due to the high ambient temperatures. While 5% higher ac voltage is unusual, 2–3% higher voltage is common on hot days, since utilities raise voltage to enable them to run more power through their distribution circuits to satisfy air conditioning loads.

**Array degradation.** System designers must be aware that the minimum voltage from a PV module, and thus an array, changes over time. All PV arrays degrade in power, both in voltage and current. At a minimum, designers should factor in an annual power loss of 0.5%.

Since no conclusive data exists regarding how much of this loss is expressed in voltage versus current, a reasonable

# Low Array Voltage

The set of I-V curves in Figure 2 assumes source circuits of 14 Evergreen ES-195 modules, with 20 circuits connected in parallel to a Satcon PVS-50 inverter with a 305 Vdc minimum MPPT voltage. The ASHRAE low design temperature is 0°C, and the ASHRAE 2% design temperature is 45°C. The latter results in a minimum array operating voltage of 289.8 Vdc. (To see the underlying design calculations, refer to "Array to Inverter Matching," December/January 2009, *SolarPro* magazine.)

As evidenced by the intersection of the dotted line and the I-V curve for the ASHRAE 2% design temperature, on the hottest days of summer when the solar resource is greatest, the inverter is unable to operate the array at its maximum power point. Any energy the inverter cannot harvest is money left on the table. This is clearly not an acceptable array design.

Adapting the design to 15 modules per source circuit gets the minimum array operating voltage up to 310.5 Vdc, which is higher than the minimum inverter MPPT voltage. However, this does not provide adequate margin to account for the cumulative effects of high ac grid voltage, array degradation or voltage mismatch. The best array design is actually 16 modules per source circuit, which results in a minimum array operating voltage of 331.2 Vdc, before any other derates are applied, and a maximum open-circuit voltage of 571.2 Vdc.

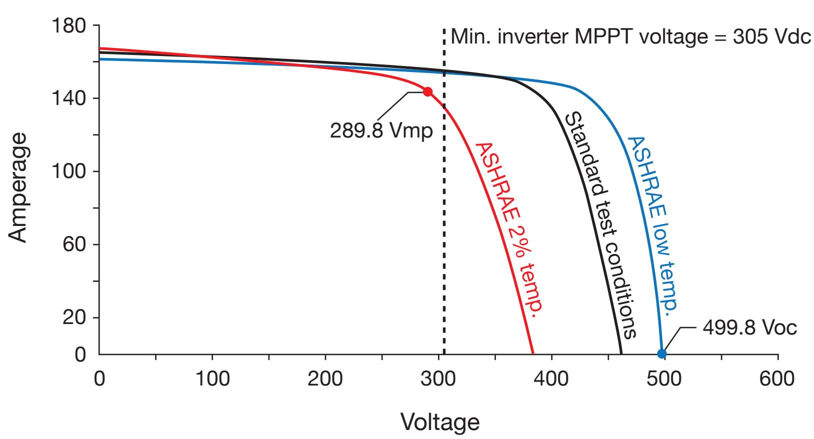



**Figure 2** With only 14 modules in series, the maximum power point for the I-V curve in red occurs below the inverter's minimum MPPT voltage.

design decision is to equally allocate the loss between current and voltage. This means that a typical array should be designed with the understanding that it will lose 0.25% or more of its voltage each year. Over 25 years, a minimum loss to calculate would be about 6% ($0.9975^{25} = 0.939$).

**Voltage tolerance.** While PV modules may have relatively tight power tolerances (averaging about +3%/-3%), the voltage and current tolerances are typically much larger—perhaps as large as +10%/-10%. This uncertainty is difficult to plan for in design. If a module is relatively low in voltage, its power specification is met by having an offsetting high current, because power is the product of volts times amps. Given the lack of information on module voltage tolerance available, it is best to err on the side of caution and assume an extra 5% dc voltage loss in the array.

**Combined impacts.** To arrive at an optimal minimum dc voltage for the array, add the effects of all the issues together. Currently, string-sizing programs calculate the minimum voltage based on the temperature-adjusted maximum power voltage of the module. If the high ac voltage accounts for 3%, array degradation for 6%, and module voltage tolerance for 5%, then the array should be designed to operate with a voltage that is at least 14% higher than the temperature-adjusted maximum power voltage for a given location.

The way to avoid problems associated with low dc voltage is to increase the array voltage. When using string-sizing programs, the simple rule I recommend is to eliminate the lowest voltage option—the source circuit with the least number of modules in series. If possible, throw away the two shortest source-circuit options. For example, if the sizing program allows 12, 13, 14 or 15 modules in series, limit the choices to 14 or 15 modules.

While this approach may work well in general, it is important for system designers to perform detailed low dc voltage calculations for specific array configurations. Designers should use the highest expected continuous ambient temperature for calculation purposes. According to the Copper Development Association, the highest ASHRAE temperature data that is likely to create a 3-hour continuous condition, per the definition of *continuous* found in *NEC* Article 100, is the 2% Annual Design Dry Bulb Temperature, which is also found in Appendix E of the *Expedited Permit Process for PV Systems*. For designers who feel that the ASHRAE 2% temperature is not high enough, the same table also includes ASHRAE Extreme Annual Mean *Maximum* Design Dry Bulb Temperature data, which can be used for even more conservative voltage or ampacity calculations.

## CASE STUDY: EXAMPLE DC VOLTAGE CALCULATIONS

This case study illustrates how to implement the high and low dc voltage recommendations described in this article. It assumes a 50 kW inverter because designers working on smaller arrays, especially those under 10 kW, can be heavily influenced by a desire to fully exploit the available inverter capacity. This often leads to array voltage compromises that are unnecessary in larger systems. The inverter in this case is large enough that its capacity does not drive array voltage design. The relevant design details for this case study are as follows.

**Location:** Raleigh, NC
**Low design temperature:** -13°C, per ASHRAE Extreme Annual Mean Minimum Design Dry Bulb Temperature
**Record low temperature:** -21°C, per Weather.com
**High design temperature:** 34°C, per ASHRAE 2% Annual Design Dry Bulb Temperature
**PV module:** Yingli YL230P-29b, 230 W STC, 29.5 Vmp, 7.8 Imp, 37.0 Voc, 8.4 Isc, -0.137 V/°C temperature coefficient of Voc (-0.37%/°C x 37.0 Voc), -0.133 V/°C temperature coefficient of Vmp (based on the published temperature coefficient for Pmp, -0.45%/°C x 29.5 Vmp)
**Inverter:** Satcon PVS-50, 50 kW, 600 Vdc maximum input, 305–600 Vdc MPPT range

**Maximum modules in series.** To determine the maximum number of modules in series, first calculate the per-module maximum voltage as follows:

$$V_{MAX} = V_{OC} + ((T_{LOW} - T_{REF}) \times \alpha V_{OC})$$

where $T_{LOW}$ is the ASHRAE Extreme Annual Mean Minimum Design Dry Bulb Temperature; $T_{REF}$ is the cell temperature at STC; and $\alpha V_{OC}$ is the temperature coefficient of Voc.

$$\begin{aligned} V_{MAX} &= 37.0\text{ V} + ((-13°\text{C} - 25°\text{C}) \times -0.137\text{ V/°C}) \\ &= 37.0\text{ V} + (-38°\text{C} \times -0.137\text{ V/°C}) \\ &= 37.0\text{ V} + 5.2\text{ V} \\ &= 42.2\text{ V} \end{aligned}$$

Divide the maximum inverter input voltage by the temperature-corrected open-circuit voltage and round down to the nearest whole number to determine the maximum number of modules in series:

$$\begin{aligned} N_{MAX} &= 600\text{ Vdc} / 42.2\text{ V} = 14.2 \\ &= 14\text{ modules in series} \end{aligned}$$

**Minimum modules in series.** To determine the minimum number of modules in series, first calculate the per module minimum voltage as follows:

$$V_{MIN} = (V_{MP} + ((T_{HI} + T_{RISE} - T_{REF}) \times \beta V_{MP}))$$

where $T_{HI}$ is the ASHRAE 2% Annual Design Dry Bulb Temperature, $T_{RISE}$ is the rise in cell temperature expected considering array mounting (typically 20°C to 30°C), and $\beta V_{MP}$ is the temperature coefficient of Vmp.

$$\begin{aligned} V_{MIN} &= 29.5\text{ V} + ((34°\text{C} + 20°\text{C} - 25°\text{C}) \times -0.133\text{ V/°C}) \\ &= 29.5\text{ V} + (29°\text{C} \times -0.133\text{ V/°C}) \\ &= 29.5\text{ V} - 3.9\text{ V} \\ &= 25.6\text{ V} \end{aligned}$$

Select and apply a multiplier to account for the combined effects of high ac grid voltage, array degradation and module voltage tolerance. 0.85 is used in this case:

$$\begin{aligned} V_{MIN} &= 25.6\text{ V} \times 0.85 \\ &= 21.8\text{ V} \end{aligned}$$

Divide the minimum MPPT voltage by the minimum voltage per module and round up to the nearest whole number to determine the minimum number of modules in series:

$$\begin{aligned} N_{MIN} &= 305\text{ V} / 21.8\text{ V} = 13.99 \\ &= 14\text{ module in series} \end{aligned}$$

**Comparison of results.** It is now possible to recalculate the acceptable source-circuit configurations using standard assumptions for a string-sizing program. There are two main differences in the calculations.

First, use the record low temperature for the location in place of the ASHRAE Extreme Annual Mean Minimum Design Dry Bulb Temperature for the $V_{MAX}$ and $N_{MAX}$ calculations:

$$\begin{aligned} V_{MAX} &= 37.0\text{ V} + ((-21°\text{C} - 25°\text{C}) \times -0.137\text{ V/°C}) \\ &= 37.0\text{ V} + (-46°\text{C} \times -0.137\text{ V/°C}) \\ &= 37.0\text{ V} + 6.3\text{ V} \\ &= 43.3\text{ V} \end{aligned}$$

$$\begin{aligned} N_{MAX} &= 600\text{ Vdc} / 43.3\text{ V} = 13.9 \\ &= 13\text{ modules in series} \end{aligned}$$

Second, do not apply a 0.85 multiplier as part of the $V_{MIN}$ calculations. This means that the minimum number of modules per source circuit is calculated using a Vmp of 25.6 Vdc:

$$\begin{aligned} N_{MIN} &= 305\text{ V} / 25.6\text{ V} = 11.9 \\ &= 12\text{ module in series} \end{aligned}$$

The best array design for this case study calls for 14 modules per source circuit. However, the simplest string-sizing program specifies 12 to 13 modules per source circuit. More sophisticated string-sizing programs apply a margin of safety to the minimum expected dc voltage to account for high ac grid voltage, array degradation and module-to-module voltage mismatch. Using PVSelect.com, for CONTINUED ON PAGE 78

example, to calculate the acceptable string sizes for this case study disqualifies source circuits of 12 modules. However, if the designer is not using ASHRAE low design temperature data, even PVSelect.com cannot identify the best design option. Assuring the best design requires both accurate calculations and proper data.

## SIZING THINGS UP

I am not suggesting that inverter manufacturers do not provide a valuable service with their string-sizing tools. Without these resources, the number of array design mistakes would undoubtedly be many times what it is today. Nevertheless, system designers routinely make mistakes, in spite of the fact that they have ready access to many easy-to-use string-sizing tools. The results of the low voltage mistakes described here are not dangerous; they do not pose a hazard to persons or property; they do not violate *Code.* They simply miss the mark of reducing up-front system cost and optimizing long-term performance. Designers need to keep in mind that all "approved" string sizes are not created equal.

From an installed cost point of view, it is always better to put the maximum number of modules in series. This delivers the greatest amount of power per pair of source-circuit conductors. Longer strings also increase the array voltage, which has voltage drop benefits when cables are sized. Getting the array voltage up also provides insurance when it is needed most against insidious low dc voltage problems that result in poor system performance precisely when the solar resource is greatest. On 5 kW or 50 kW net-metered projects, the difference in performance between having 14 modules in series or 12 or 13 modules in series might not register with the customer. However, on 500 kW or 5 MW projects that are PPA financed, this will make a world of difference in both the installed costs and the revenue generated over the life of the systems.

### CONTACT

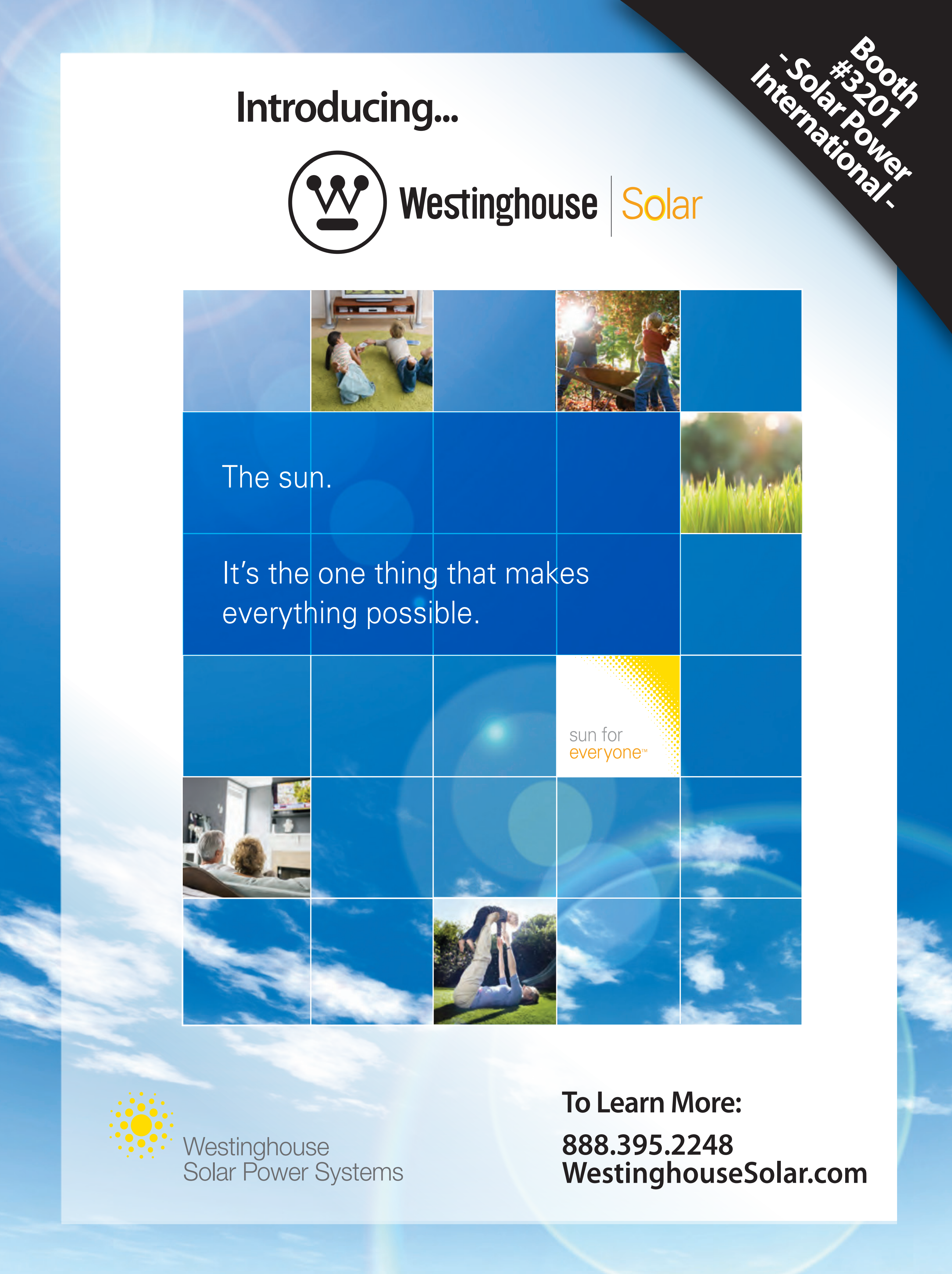
Bill Brooks / Brooks Engineering / Vacaville, CA / bill@brooksolar.com / brooksolar.com

**Resources**

American Society of Heating, Refrigeration, and Air-Conditioning Engineers / ashrae.org

Blue Oak PV Selection Tool / pvselect.com

Solar America Board for Codes and Standards (Solar ABCs) / solarabcs.org/permitting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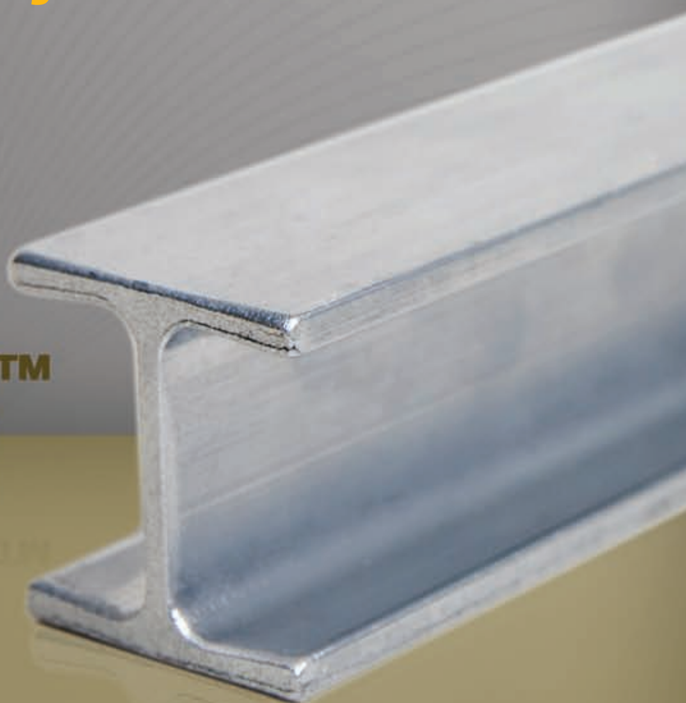

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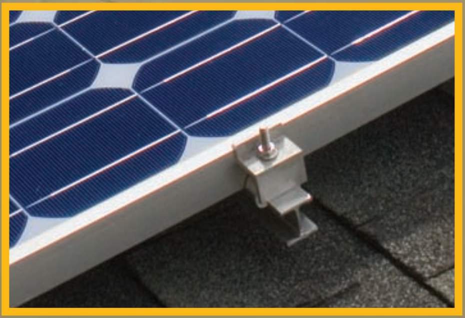

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# Operations Management for Solar Integrators

By Darlene McCalmont

In this article, I focus on the operations management functions within a residential or small commercial PV systems integration company. While I do not specifically cover other types of renewable energy installation companies, manufacturing, engineering or other service-oriented organizations, my suggestions apply to those businesses as well. The key elements of operations are the same in any business; they just may be applied differently.

This article details operations management strategies that have worked well for me. The content is generally organized from inside to outside the office, post-sales through project closeout. Basic principles for optimizing personnel, resources and processes are all considered.

## FUNDAMENTALS

As defined by Fisher College of Business, at the Ohio State University, *operations management* is "the systematic direction and control of the processes that transform inputs into finished goods and services." In common parlance, the term *operations* is often used to mean operations management, but technically it refers to jobs or tasks that make up processes. As noted by Carter McNamara, co-owner of Authenticity Consulting and developer of the Free Management Library, "Usually, small businesses don't talk about 'operations management,' but they carry out the activities that management schools typically associate with the phrase."

For a solar integrator, the operations function is, basically, whatever must occur once a sale is completed in order to honor the commitment to the customer. It directs processes like scheduling, permitting, purchasing, inventory management, installation, commissioning and inspection. It controls resources like facilities, vehicles, tools, computer hardware or software. These and other inputs are essential to

### Operations Organizational Chart

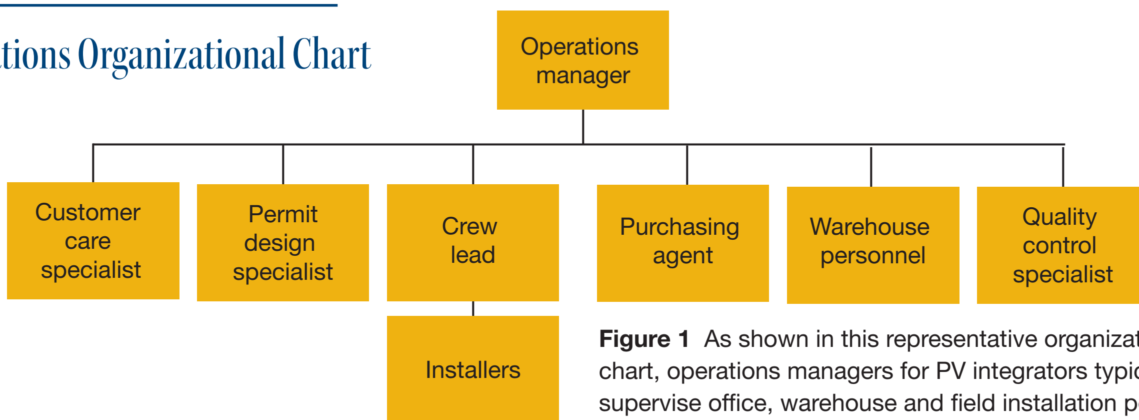
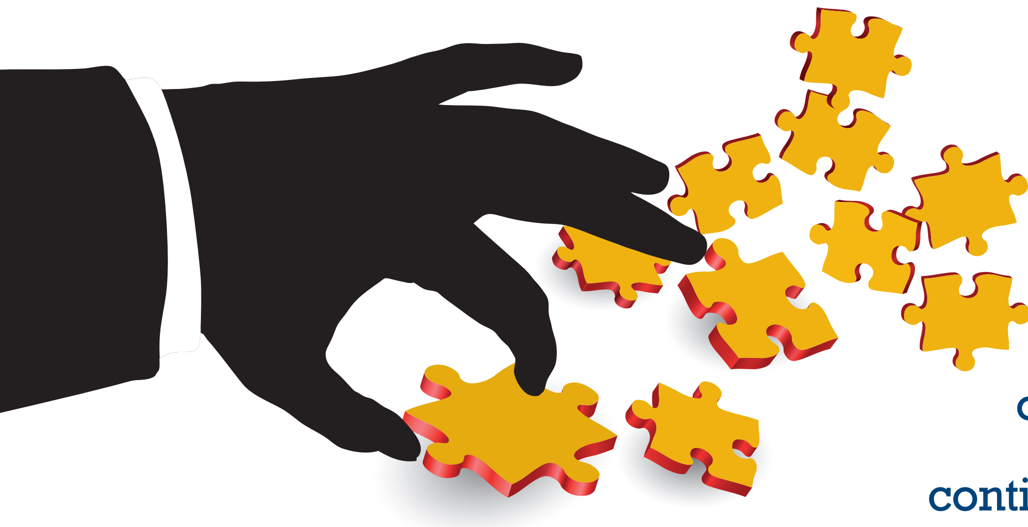



**Figure 1** As shown in this representative organizational chart, operations managers for PV integrators typically supervise office, warehouse and field installation personnel. They are also responsible for the resources all personnel require and a host of internal processes.

Courtesy McCalmont Engineering



More than merely overseeing activities that result in an end product, operations managers continually analyze every step of the process, looking for ways to improve efficiency and effectiveness.

the process of delivering a product—in this case, the installation of a PV system.

## THE OPERATIONS TEAM

The size of the company determines the size of its operations team, which performs both bureaucratic and customer care functions. In a young company, employees tend to wear multiple hats. The business owner may initially serve as president, CEO, CFO, COO and janitor; the company's first crew leader may also have to permit, commission and maintain systems. No matter which other hats are worn, everyone in operations must wear the customer care hat.

As the company grows, it is important to define, streamline and specialize roles and responsibilities. An example organizational chart for a PV integrator's operations team is shown in Figure 1. Brief descriptions of each role follow.

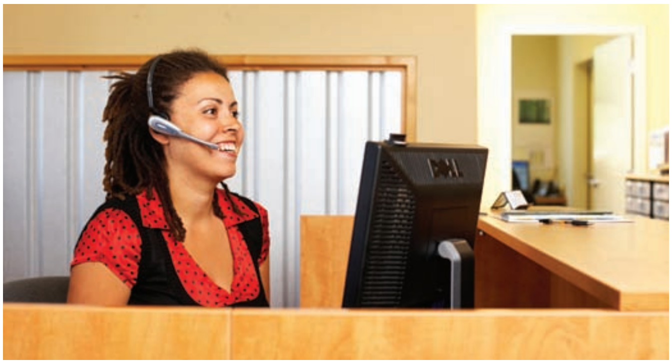
**Operations manager.** As leader of the operations team, the operations manager determines its organizational structure and workflow processes. If these are functioning well, customers, employees and management all benefit. Perhaps the most important measure of operational effectiveness is customer satisfaction, as a solar business cannot thrive without happy customers and their referrals. This means that quality control is a priority for operations managers, who must see to it that internal standards are set appropriately. They are ultimately responsible for staff training, professional development and evaluation. Operations managers are also concerned with cost reduction, which is a good measure of operational efficiency. Quality, efficiency and cost reduction are ultimately major contributors to customer satisfaction.

Because efficiency and effectiveness are so critical, an operations manager is not merely concerned with the tasks involved with delivering an end product. Some component of measurement and analysis is also required, such as project profitability analyses or cost-benefit analyses for new products. As the margins for a solar integrator are fairly low, cost reduction measures should be ongoing. Whether you are in the business of installation, manufacturing, engineering or providing some other service, internal process improvement is always possible.

**Customer care specialist.** Ideally customers should have to remember the name of only one person in the operations department. That name belongs to the customer care specialist, who is the only one customers should receive calls from concerning the installation process—and who holds one of the most important positions. The key job functions can include:

- Being the liaison between the company and the customer
- Explaining the process from sale through interconnection

- Calling the customer to schedule the installation
- Following up with customers, so they remain in the loop and "feel the love"
- Maintaining a full schedule at all times to keep crew(s) in the field
- Working with the permit design specialist to be sure the permit is ready when needed
- Communicating with the sales manager to address areas of improvement that can streamline the process and improve efficiency
- Forecasting specific material needs to the purchasing agent 4 months into the future



Courtesy REC Solar

**Customer service** As the liaison between the solar integrator and the customer, the customer care specialist holds one of the most important positions at a company.

Only a true "people person" can perform this job well. Many days are largely consumed with phone calls. The customer care specialist needs to excel at explaining tough situations to customers. Customers' experiences with this person can turn their perspective of the company from good to bad. For a business that should be receiving at least 50% of its leads from referrals, it is unacceptable to have unhappy customers.

**Permit design specialist.** The task of producing a permit package for the customer's installation belongs to the permit design specialist. Since a crew cannot perform any portion of an installation until the permit has been issued by the AHJ, permitting is an important next step upon contract signature. The permit design specialist must have the technical knowledge and CAD experience required to produce permits, as well as the field experience and technical knowledge to confidently answer questions from building officials. The key job functions include:

- Working with the customer care specialist to prioritize permits
- Keeping track of the various building jurisdictions' requirements and timelines
- Preparing the crew installation package

Permit design specialists do not need fine-tuned people skills, because they rarely speak with customers. They do, however, need to be able to communicate effectively with building officials and crewmembers. Depending on the size of the company, the permit design specialist is likely to visit the building department and file for the permit.

A permit for a residential PV system is made up of two main sets of documents: the roof layout, site plan and elevation drawings, and the electrical drawing and calculations. The permit design specialist should be able to produce both sets of documents, which requires an understanding of both the mechanical and electrical aspects of an installation. The permit design specialist for some companies is an engineer, but a nontechnical person can be trained to develop and submit residential permits if provided with the correct tools. The use of computer software for electrical calculations and drawings can save significant expense in this area. SolarNexus, for example, is developing a software solution specifically for solar integrators. There are also companies that produce or submit permit packages or both for a fee, such as Burnham Energy, a subsidiary of Burnham Nationwide (see Resources).

**Purchasing agent.** Depending on the company size, the purchasing function may fall within operations or finance—but because of its cash flow implications, purchasing should eventually reside within the finance department. A dedicated person on-site should be charged with maintaining inventory for high-cost items such as modules and inverters. Racking must be managed closely, because it may require a long lead time.

**Warehouse personnel.** Hiring a part-time employee who works for about 2 hours every evening after the crew trucks return is more cost-effective than having your crews stock their own trucks. This person can stock the storage compartments, charge the batteries for the drills, load the modules and inverter(s), and, in short, prepare the truck for the crew the next day. As the business grows, this can become a full-time position, staffed by a warehouse person who not only stocks the trucks but also takes deliveries and works with vendors and purchasing.

**Crew lead and installers.** The crew size on residential and small commercial installations can float between two and four installers, with three being ideal for most jobs. One of these should be a lead installer who understands all aspects of an installation. The other two installers can have varying skill levels. Ideally, one of them should have the ability to work the roof and dc side with little to no supervision. The third installer can be as inexperienced as a trainee. While it sounds ideal to have a crew where all three installers can handle any portion of the installation with no supervision, it is difficult, in practice, to grow a company while exclusively using fully experienced installers. CONTINUED ON PAGE 86

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**Quality control specialist.** The inspection with the permitting jurisdiction happens soon after the installation is complete. This inspection is the perfect time to have an unbiased person do quality control checks and perform the formal commissioning of the installation, which verifies and completes the commissioning steps performed by the crew. Installation practices must be maintained at the quality level that management determines for long-term safety and reliability, and having a dedicated quality control specialist is one way to accomplish this.

Courtesy Green Logic

**Installation crew** A crew of three works well for many residential installations. The crew lead must understand all aspects of the installation, and ideally at least one of the installers is experienced enough to work unsupervised.

Those doing the commissioning and internal inspection need to have knowledge of the company's installation standards and must also be capable of making quick and easy corrections. Ideally, they should not be from the installation team, because that defeats the desired lack of bias. (For a detailed description of the commissioning process, see "PV System Commissioning," October/November 2009, *SolarPro* magazine.)

The person meeting the inspector can either be a well-trained employee specializing in inspections and commissioning or someone from an outside firm, such as Burnham Energy, that provides these services to others. Building a relationship with inspectors is very important. Using a limited number of company personnel for inspections assures that the building official sees the same person multiple times and begins to associate the quality of the installation with that person on-site.

The quality control specialist can also take the as-built solar access readings. It is more cost-effective to train a small number of people to take Solmetric SunEye or Solar Pathfinder readings than it is to have all the lead installers performing this task. Providing internal feedback on any installation issues observed in the field is another good use of this person's time. For individual issues, the quality control specialist should follow up one-on-one with the lead installers, but for common errors or training concerns, they should periodically present issues in classroom training sessions for the benefit of all crewmembers.

**Other.** Depending on the company's specific business model or organizational structure, its size or maturity, other job descriptions may fall under the umbrella of operations. For example, a larger, more established company might develop the need for full-time service department personnel. This emphasizes the need to continuously evaluate operational efficiency and effectiveness.

## IMPROVING THE BOTTOM LINE

While it is great to work with people whom you enjoy and who perform quality work, if the company is unable to turn a profit, the business is not sustainable. It is well known that margins for PV integrators are low. Finding better methods of doing things is a constant mission. Before any fieldwork is attempted, much preparation should occur so the installation crews can be productive and work at peak efficiency. This includes information, inventory, personnel and process management.

### INFORMATION MANAGEMENT

Part of an efficient operation is keeping all your customers' information organized. It is also critical to clearly communicate relevant information to the crew.

**Organizing customer information.** Using a well-designed computer system prevents having to look through stacks of papers or computer files. While the up-front cost and setup time may sound daunting, the resulting time savings and increased efficiency are huge. All employees who need access to the data must be trained so that documents are filed accurately each time.

Each master file is organized on the server according to the customer's last name, then first name. One efficient filing method is to identify the different departments that deal with customers, create a subfolder for each, then separate and file customer data and digital documents pertaining to each department accordingly. The following is a sample filing method, with a few of the digital documents that would be filed under each department.

- Sales
  - Site survey, including any notes from the salesperson
  - Shading assessment from Solar Pathfinder or Solmetric SunEye
  - Sales documents, such as signed contracts
- Incentive
  - Reservation forms completed and filed

CONTINUED ON PAGE 88


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- Claim forms completed and filed as part of the incentive claim

■ Operations
- Permit documents
- Crew package for installation
- As-built documents, including string configuration and final layout if any changes
- Commissioning form, including quality control checks
- Serial numbers for modules and inverter(s)

■ Interconnection
- Completed utility-specific interconnection forms
- Any related documents

■ Finance
- Purchasing documents
- Customer invoices

Organizing customer data may begin with lead management in the sales department. Once the sale is complete, however, this responsibility largely resides with operations.

Since repeat tasks are best done on a computer, use software that enables employees to work as efficiently as possible. Third-party solar software solutions, like Clean Power Finance or SolarNexus, include varying degrees of file management functionality (see Resources).

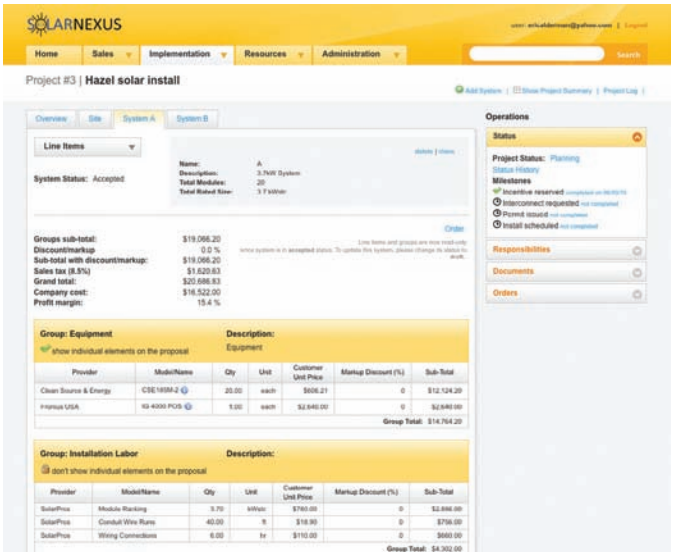
**Crew package.** While preparing the permit package, the permit design specialist also generates a crew package. Time and care should be taken to do this effectively, and it is important to include a review with the crew lead. The first morning of the installation, either the customer care specialist or the permit design specialist should go through the crew package with the crew lead and point out specifics to be highlighted. However, a well-prepared package should be self-explanatory.

Twin-pocket portfolios work well for these packages. They can be identified with the customer's last name on an adhesive label in an upper corner and reused until worn out. Contents of the crew package should include copies of the permit and plan set documents, sales notes, the bill of (major) materials and a commissioning worksheet. Duplicate copies of the permit and plan set can be placed in the right-hand pocket so that the staff and crew can make as-built notes directly on them, thereby keeping the original documents clean. Any pertinent notes from the salesperson can be placed in the left-hand pocket, along with a list of materials needed for the installation. This list does not have to include fittings and small parts, but rather just the major components that do not have a designated place on the crew truck. For example, list the type, quantity and size of modules and inverter(s), racking parts, disconnects, breakers, conduit and any unusual item that would not normally be stocked on the truck. A blank commissioning worksheet for the crew to complete at the end of the installation should also be in this pocket.

The folders are filed alphabetically according to customers' last name until needed. Once the job is complete, crewmembers return the entire package along with their notes. All documents must be given to the customer care specialist. Serial numbers and warranty cards for modules and inverters must also be turned in, either by crewmembers or warehouse personnel. The folder is then relabeled and reused for another customer.

## INVENTORY MANAGEMENT

It is critical to maintain a balance between too much inventory, which affects cash flow, and too little inventory, which could affect revenue. It is also helpful to minimize the number of parts and vendors that need to be tracked. If the budget




Courtesy SolarNexus

**Software solutions** To date, solar integrators have used software primarily in their sales and engineering departments. One company looking to change this is SolarNexus, which has released a next-generation software platform that it hopes will also streamline typical operations processes and procedures, such as incentive reservation, interconnection requests, permitting, ordering and scheduling.

can support it, however, bulk purchasing is better than small individual job packages. Not only is the price cheaper per watt for a bulk order, but also the time spent receiving delivery and stocking shelves is lessened due to packaging differences. There are also fewer purchase orders and invoices to process.

Small parts are needed to complete the installation. While some integrators have their crewmembers stop at the electrical parts store and pick up what they need for each installation, a crew of three stopping to pick up parts that can be stored in the warehouse is not CONTINUED ON PAGE 90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cost-effective. Crews need to be at the customer site generating revenue, not shopping. Many small-parts companies, such as Fastenal, and some electrical suppliers offer vendor-managed inventory (VMI) for little or no extra cost. The vendor establishes on-site shelving with bins for various parts with a predetermined minimum and maximum for each bin, which they keep stocked. With VMI, the parts are always in the warehouse. Since the vendor handles the paperwork, there is less need for purchase orders and invoices are drastically reduced. As your business grows, the minimum and maximum levels in the various bins can be adjusted easily. With VMI for small parts and electrical parts, your purchasing person mainly concentrates on modules, inverters and racking.

**Warehouse.** The physical layout and management of the warehouse affects operations efficiency and the ability to load crew vehicles easily. Neatness and organization are synonymous with efficiency. Too much time is spent searching if parts are scattered throughout the warehouse. Organize the small parts closest to the crew vehicles so they can be loaded quickly. A heavy-duty wheeled cart can be used to roll small parts to the truck for stocking. Modules and inverters are bulky and most easily moved by pallet jack or forklift, so they do not have to be stored in the immediate vicinity of the truck.

**Work vehicles.** Choosing and efficiently organizing work vehicles can affect the bottom line as well. A super-cab layout with a 9-foot cargo body and a heavy-duty sliding bed for ease of reaching parts at the front is ideal. With this arrangement, two to four installers can be seated in the cab and have sufficient room for parts in the compartments and truck bed. Other companies prefer box trucks or Sprinter vans outfitted with organizers. It is important to take some time and to utilize the crewmembers to help decide what layout works best for them in the field.

Just like a warehouse, a crew truck tells a story about the company and the crewmembers. Good crew leads take pride in their trucks and understand how important it is for efficiency. If a truck is properly loaded and organized, a crew can have all parts necessary—including modules and inverters—for the entire day of work. If there is more than one crew truck, then all trucks should be loaded the same way so that any crewmember can move from one truck to another and always know where the parts are stored.

With many different ways to organize the parts, the important thing is that they be placed logically. For example, since the majority of residential installations require either ¾- or 1-inch conduit, ¾-inch parts can be on one side of the truck and 1-inch parts on the other side. Separating parts by dividers makes it easier to find what is needed. All racking small parts should be together. A conduit box on the top of the truck can hold a large supply of ¾- and 1-inch conduit with the ability to add larger sizes and some Unistrut when needed. Using every available spot on the truck to store parts, including the cab door pockets, increases efficiency.

For example, you can use a small plastic box with compartments to hold different-size drill bits that are needed for all typical drilling functions on the installation. It can also hold spare cutting wheels for a conduit cutter. Since it is not needed every day, it can be placed in the door pocket of the truck cab. Canvas bags of various sizes work well for wire management clips, ground lugs and so on because these bags are sturdy, have a long life and do not slide easily on roofs. You can use a large plastic box to carry miscellaneous screws, nuts, washers and so on used by the ac side installers—they just take the whole box to the location, which saves numerous trips back to the truck. Finally, be sure to label the individual compartments in the truck so it is easy to identify what is supposed to be there in case the crew depletes a compartment on a given day.

**Tools.** The crew truck can quickly be overwhelmed with crewmembers' personal tool bags and lunch boxes. It is possible to minimize this if the company CONTINUED ON PAGE 92

**Inventory management** Choosing the best component storage solution, such as cantilever racks for mounting rails and conduit, can improve efficiency in the warehouse.

Courtesy McCalmont Engineering

provides some of the larger, more expensive tools. This might include a circular saw, a reciprocating saw, a conduit bender, fish tape, extension cords, a voltmeter, an angle grinder, a sledgehammer or hammer drill or both. Generally only one of each is needed per job site, but consider providing enough battery-operated drills with spare batteries per truck to match the number of installers that day.

Each crewmember should provide the rest of the small hand tools that an installer needs, such as screwdrivers, hammers and wrenches. Whatever the tool policy, installers should not bring tools to the job sites that the company provides.

Good management leads to loyal employees. Companies that fail to instill loyalty in their employees run the risk of becoming training grounds for other integrators.

## PERSONNEL MANAGEMENT

A company is only as good as its management. Good management leads to loyal employees. Companies that fail to instill loyalty in their employees run the risk of becoming training grounds for other integrators.

**Communication.** The most important thing a manager can do is listen. Finding time to identify and address the issues and concerns facing employees is essential. Managers should take the time to stop by the offices of their personnel several times a week, for example, just to ask what they can do to help. The better managers know what their people actually do, the more employees will respect their managers and view them as mentors. Not everyone in operations management starts from the bottom, but understanding the job functions of the staff and crew is important if a manager wishes to earn their respect. Do not underestimate the value of keeping a positive morale among employees—they are any company's best asset.

Being available for installers takes special effort, especially given the work hours. Nevertheless, managers should make it a habit to be in the warehouse before the trucks leave or when they return in order to check the crew's pulse. It is important to give crewmembers positive feedback or help them work out a solution to a problem. Visiting installers at the customer site gives a manager the chance to see their work first hand. Good installers are proud of their work and are pleased when a manager takes time to stop by.

Managers should hold formal meetings with the entire operations staff and crews on roughly a monthly basis. At these meetings, management should share relevant data regarding company performance and follow this with open discussions. Whatever the management style might be, it is important that it is consistent and fair. Standards should be kept high because demanding the best from employees leads to a strong corporate culture. It is also important to maintain employee involvement in making key decisions. Better ideas emerge by utilizing all levels of the company. Employee involvement leads to employee satisfaction—and happy employees produce better installations, happy customers and a healthy bottom line.

**Crew training.** Assuring that well-mannered, trained installers are sent out to the customer site is important for customer satisfaction and a company's long-term reputation. Crews must uphold the company values of integrity. They are entrusted to install a system that will not cause warranty issues due to leaking roofs, poor performance or poor

Topher Donahue

**Standard operating procedures** In addition to product installation manuals, a book of standard operating procedures can include details on safety rigging, flashing attachments and other roof penetrations, wire management, grounding and bonding, leveling and squaring arrays, and so forth. This information should be kept on every truck and updated after training sessions, as installation standards evolve or new equipment is introduced.

aesthetics. They should not engender customer complaints by leaving trash at the site or causing damage. Good installers must have technical and mechanical aptitude, as well as good communication skills to converse with customers and colleagues.

Crew training should include both classroom and on-the-job experience. Some technical aspects are best learned in a classroom, particularly the ac electrical side of the installation. Other aspects, such as layout, racking and module installation, are best covered on the job after some classroom training. Most installers tend to be hands-on learners. Lead installers should be charged with planning the training of their new installers in the field. Classroom sessions should be kept short and cover a specific issue. It works well to combine these training sessions with mandatory safety meetings at the start of the shift and to cover a topic for about 30 minutes before the installers leave in their trucks. Experts in the company, such as an engineer, master electrician, quality control specialist, operations specialist or manager, should teach classroom sessions.

## PROCESS MANAGEMENT

The potential for process improvement exists at all stages of the business. It is important to define and document processes, in part to protect against disruption during personnel changes. It is also easier to evaluate and refine a process once it is documented.

**Standard operating procedures.** Installers need to know that when they work for a different crew lead, processes do not change. Ideally all procedures are written down in a standard operating procedure (SOP) book. This can be time-consuming to produce, but manufacturer's instruction sheets are helpful as a starting point. These can be placed into a notebook to serve as reference material. Initial items for the notebook include module, inverter and racking company installation guides, technical articles from *SolarPro* and other publications, and company memos. This notebook should include specification sheets for all modules and inverters your crews might install. An SOP book and an *NEC Handbook* should always be on each truck.

**Crew workflow.** With the exception of travel time to and from the job site, crews should be working in the field. Work in the field should be organized as evenly as possible so the crewmembers can finish together. In a simple rooftop residential system, there is dc work on the roof and ac work on the ground. A good two-person roof and dc crew can complete most of the roof work, depending on their experience level. They can manage the array layout and determine the attachment points, then install the rails, conduit and dc wire and prepare for the modules. Meanwhile, the ac side installer is working at the inverter location and can help when it is time to transport the modules to the roof. Once all of the ground preparation is complete, the ac installer may need help mounting the inverter, depending on its size and weight. Most ac side installers can do the rest of the ac side alone, unless there is a long ac wire run.

**Crew schedule.** Work hours are another area to consider for efficiency. Travel time does not generate revenue. Therefore, switching from a 5-day, 8-hour-per-day workweek to a 4-day, 10-hour-per-day workweek may increase the percentage of time that the crew is generating revenue. A four 10-hour-day schedule tends to work well, except for locations where afternoon temperatures are too hot or there are just not enough daylight hours. An installer with a full paycheck is also a happier installer. This schedule allows the flexibility to work the crew around rain days and still maintain 40 hours for the week—and crewmembers love the 3-day weekends.

> As an organization grows, operational efficiency and effectiveness become increasingly important. Fortunately, a company with solid operations is well positioned for growth and expansion.

Installers should be hired at a rate that controls and sustains 2 months of working backlog. Include the current installation team as part of any installer hiring process. Crewmembers work together for 8 to 10 hours a day, and if personalities do not work well together, it does not matter how good someone is with a drill. It is a good idea to try out new crewmembers as independent contractors for a few days to see how they fit, both mechanically and personality-wise.

Overtime is another consideration when scheduling crews. If they can finish a job in 30 to 60 minutes of overtime instead of cleaning up, driving back to the shop and then going back to the site the next day for a short period, it is cost-effective to have them work the overtime.

**Project closeout.** After the installation, the customer care specialist should check with the customer for feedback. This can be in the form of a mailed questionnaire, a telephone call or an email. The email method saves paper and postage, gives you a record of responses and—with the right software—can be automatically generated. Customer feedback should be compiled and reviewed so that problem areas can be addressed. Excerpts from these letters are great to post on the company's website as customer testimonials and to share with employees. It is also a great time to ask for referrals.

Customers should receive an operating manual that explains how their system operates and provides warranty information, as-built drawings, the specifications of their system including serial numbers, and their signed-off permit. If unfortunate circumstances arise that force an integrator to shut down, at least customers are not left without the ability to have someone else service their system easily.

All documentation regarding the customer should be placed in a secure file. Preferably, all of this information is loaded onto the company's computer system, but at a minimum it should be stored in a dedicated paper file. It is highly likely the site will be revisited for some reason in the 25 years following the installation.

**Service calls.** Invariably customer service calls occur, whether it is to change out an inverter, to remove modules for a reroofing or for a module warranty issue. These calls should be tracked carefully in a shared company spreadsheet noting the reason for the call as well as the findings and corrective actions. If a replacement inverter or modules are required as a result of the service call, typically someone in operations or finance handles the return merchandise authorization. If the service call requires an equipment replacement, customer records should be updated to reflect the new serial numbers. The quality control specialist or crew can handle the actual service call, depending on its nature. Service calls are definitely a disruption to the business, and efforts should be made to minimize them. A periodic scan of the service log can identify repeat failures that should be addressed.

## GROWTH AND EXPANSION

Operations management does not happen in a vacuum, but rather within the context of a broader organization and a dynamic market. As your organization grows, operational efficiency and effectiveness become increasingly important. Fortunately, a company with solid operations is well positioned for growth and expansion. The topics discussed in this article can serve as the template for future success.

### CONTACT

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Clean Power Finance / 866.525.2123 / cleanpowerfinance.com

Fastenal / 507.454.5374 / fastenal.com

SolarNexus / 510.842.7875 / solarnexus.com

# Interview

An Experienced Perspective

## John Berdner, SolarEdge Technologies

### Changing the US PV Industry…Again

John Berdner has more than 25 years of experience in the design, manufacture and use of PV equipment and systems. As the founder and president of SMA America, John was integral in launching the first UL-listed grid-direct string inverters with 600 Vdc source circuits, which revolutionized the way utility-interactive PV systems are deployed in North America. In April 2010, after serving as the VP of technology for groSolar, he joined SolarEdge, an Israeli power electronics start-up that offers module-level dc-to-dc optimizers, transformerless fixed-voltage inverters and web-based module-level performance monitoring. As the company's North American general manager, John is once again poised to bring disruptive, next generation PV technology to the North American market.

*—Ryan Mayfield,* SolarPro *magazine technical editor, recently spoke with John.*

**John Berdner, general manager, North America, SolarEdge Technologies** In many ways, the modern era of grid-tied PV in the US began with the introduction of SMA Sunny Boy inverters, a revolution that John helped to bring about. He is once again introducing an emerging technology to the North American market with SolarEdge power optimization products.

**RM**: When did you begin working in the PV industry?

**JB:** After graduating from UC Davis with a degree in mechanical engineering in 1983, I worked for a small company in West Sacramento called Solarize. After the company wound down along with the tax credits, I went to work for Solarex in its Sacramento office. When I didn't want to move to Washington, DC, for Solarex, I took a position with Photocomm outside of Grass Valley, California. This is where I met Ron Kennedi, Christopher Freitas and Sam Vanderhoof. That position led to Endecon Engineering and Chuck Whitaker. After that, I moved to Ananda Power Technologies, which became Pulse Energy Systems. Eventually, this led me to SMA, where I helped open the US offices. And then at SMA, I helped bring the German product to the US market.

**RM:** What sorts of projects were you involved with in those early years?

**JB:** Right out of school, I started on the Dixon City Hall Project, an approximately 20 kW grid-tied system. It was a third-party–financed system, what we'd call a PPA today. At Solarex, I was doing technical services, engineering and system design. At Endecon, I did some research on PV and batteries. We were looking at PV for utility-owned off-grid systems and as a demand-side management tool. Around 1992, Endecon helped the Trace SW qualify as the first type-tested PV inverter for utility interconnection for Pacific Gas and Electric. Prior to that, you had to have a utility protection engineer come out and run tests on every single system.

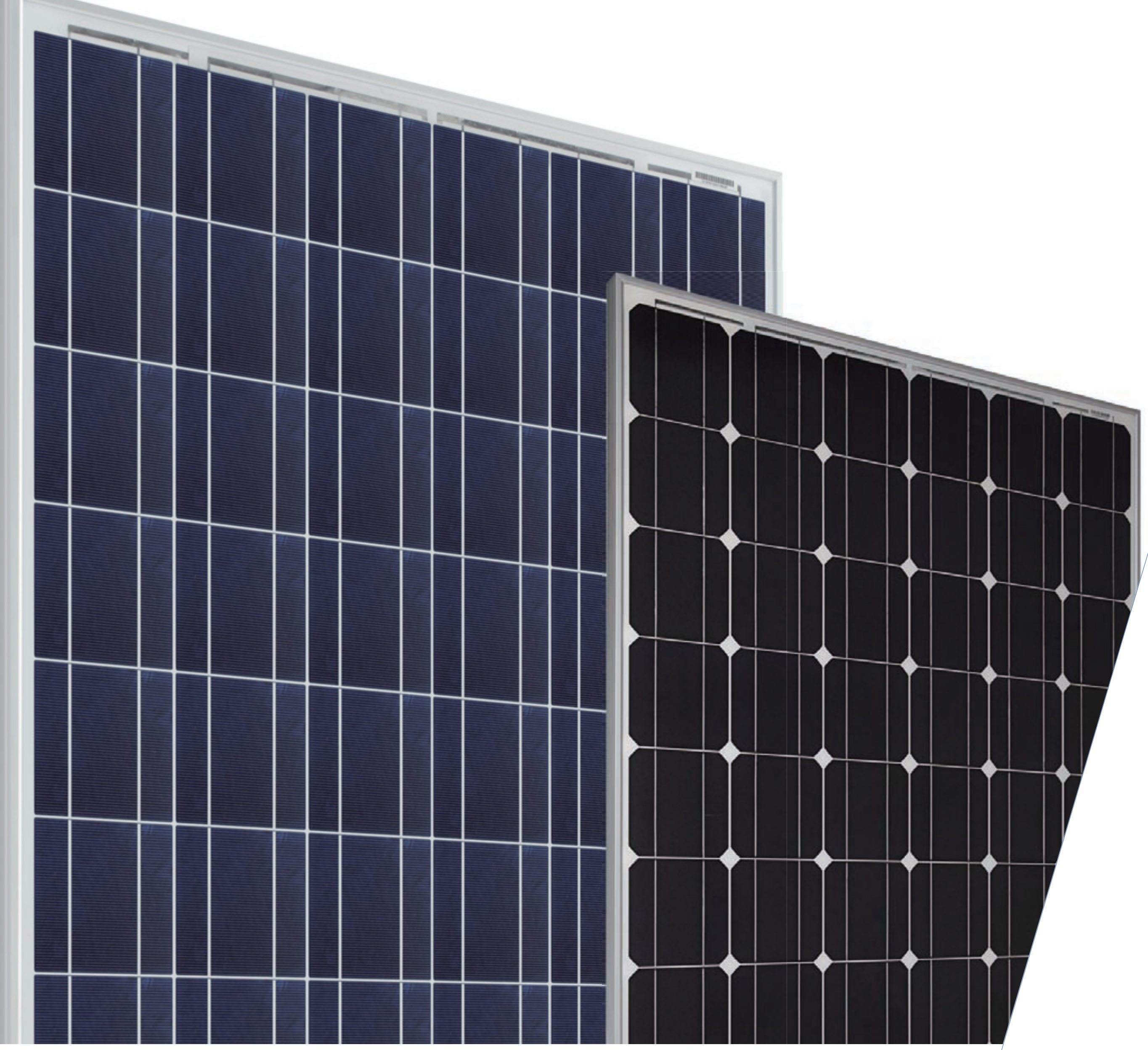
**RM**: What was the state of the US grid-tied PV industry and its inverter technology in the US when you incorporated SMA America?

**JB:** Essentially, the players in the US were Omnion, which had a high-voltage dc product; Advanced Energy, with its GC-1000, which was a 48 V pure grid-tied type; and Trace, with its Trace SW, a 48 V battery-based inverter, and later, the Sun Tie inverter, another 48 V grid-direct inverter. There really wasn't much of a grid-tied market at that time.

California had a $5-per-watt rebate program, but despite that the market really wasn't gaining any traction. The Trace SW was the most reliable inverter of the group, but you had to use batteries with it, which added a lot of significant expense, and the efficiency was pretty low. The other players, AE, Omnion and Trace's Sun Tie, were all suffering from reliability problems.

**RM**: What were your biggest challenges in bringing the SMA line to market?

**JB:** The main challenge, internally, was adapting the inverter to US regulatory and UL requirements. Essentially, that meant adding a GFDI circuit. The 2500U is transformer coupled and uses a low-frequency transformer that's typical for older, isolated inverter topologies. In Europe, it runs ungrounded, but in the US, we require grounded arrays. As a result, we had CONTINUED ON PAGE 100





to develop ground-fault–protection circuitry and put that into the 2500U. Getting people to understand that high-voltage dc was allowed by *Code* was probably one of the bigger challenges in getting it into the market.

Installer education was another challenge for SMA when we brought the first inverters to the US market. Most of the existing installers were off-grid folks. We had to do a lot of educating in regard to grid-tie installations, including anti-islanding, string sizing, safety, troubleshooting, ground faults and all the other issues surrounding it.

**RM**: How did array string sizing evolve with the introduction of the 600 Vdc inverters?

**JB:** When we started, I manually calculated every job on my HP calculator. It was clear that was not a good long-term solution. Essentially, we had to develop the string-sizing calculator from scratch. They had a string-sizing program in Germany, but it only had one weather data point, which was Freiberg, Germany. It didn't do what installers were asking of a string-sizing program. I worked with Bill Reaugh to develop the string-sizing calculator for the US market. It started as a rudimentary Excel spreadsheet, which Bill refined and then converted to a web application.

**RM**: You are once again working with an emerging technology. What is it about SolarEdge that convinced you it has a winning solution?

**JB:** First and foremost, it's the system-level approach. SolarEdge looked at the problems of PV design at a system level and asked, "How can we address all of these problems together?" What intrigued me about the personnel at SolarEdge was that they basically had answers for almost all the questions I asked. They seemed to offer one of the more well-thought-out solutions. They shared some of their reliability philosophy, test data and test protocols. Reliability is paramount when we talk about something that module manufacturers are going to embed on a PV module. We need 25-year reliability, and developing power electronics that are going to live on a module in a high-temperature environment is a significant engineering challenge. SolarEdge seemed to have the most mature solution out there.

> Reliability is paramount when we talk about something that's embedded on a PV module.

The founders of SolarEdge all came out of the Israeli military, designing hardware for military satellites. They have a background in high-reliability power electronics. Plus I like start-up companies. I like to look for new technology and help bring it to market. And I like to help grow companies.

**RM**: How do you see power optimization products benefitting the industry?

**JB:** You can really classify it into four areas of benefits: design freedom, performance, safety and system monitoring.

By allowing designers to essentially get rid of the string constraints and minimize shade issues, you have much greater design freedom.

When you do module-level MPPT, shading impacts that module only. When you go to distributed architecture with module-level MPPT, whether it be dc-to-dc or dc-to-ac, it is not unusual to see a 15% improvement in systems with partial shading.

Several of these types of products greatly improve installer and firefighter safety as well. One of the global concerns in the firefighting community is that they essentially have to leave the voltage on the roof. They can't turn it off, and they can't isolate it into safe voltages and currents. In a traditional system design, they still have high-voltage dc on the roof even if they turn off the grid-tied inverter. That's a significant hazard. Many of the distributed module-level power electronic solutions, including SolarEdge's, can help solve this problem. If the inverter is shut down for any reason, the individual SolarEdge Power Box at each module automatically goes to a safe voltage of 1 V per module. Microinverters are similar in the sense that they keep the dc voltages at a safe level when the inverters are turned off. All of these features cost money, and the resulting higher energy yield is what helps pay for all this.

Monitoring at a residential level is certainly interesting; but at the multi-megawatt level, it really is an essential maintenance tool and a way to ensure high-energy production over a long period of time.

**RM**: Do you feel like optimizers are niche products—say for residential systems or systems smaller than some capacity threshold—or do you see potential for a broader range of applications?

**JB:** In every system design, there are trade-offs. There are certain approaches that are more appropriate for one size or type of system over another. I believe for very small systems, less than a couple kilowatts, microinverters make a lot of sense. Above that, say at around the 3 kW range, distributed power optimizers start making a lot of sense.

As you start getting up in size, you move into using a distributed architecture with separate inverters, essentially single-phase or larger 3-phase. That makes sense up to the 100 to 500 kW range. People need to start reconsidering some of their misconceptions about smaller inverters, especially the newer transformerless inverters. These topologies make sense up to the several hundreds of CONTINUED ON PAGE 102

kilowatt range. There are still some significant benefits up into the megawatt scale. When you start dealing with large plants, it's purely a decision based on economic analysis. With embedded power electronics—already on the module, as opposed to having something that's mounted on the rail or on the frame—you gain some cost efficiencies. When we have modules from multiple suppliers with embedded power electronics, I think we'll see that the range of application extends into the tens of megawatts, but it's going take a little time.

**RM**: What do you anticipate will be the biggest barriers to adoption?

**JB:** Education and track record. People need to get comfortable with the reliability of these products, get some proven track record on increased performance and recognize the benefits of module-level monitoring. I don't think it's a technological barrier. For our Power Boxes, I don't think long-term reliability is truly an issue.

**RM**: You've been instrumental in helping develop UL standards over the course of your career. What codes and standards issues are on your radar right now?

**JB:** I would say that arc-fault detection is most significant. It's very likely to be a requirement in the 2011 *Code.* We are just finalizing the answers to questions such as: What is an arc? How fast do you have to detect it and under what conditions? We need to have well-defined test standards that allow us to say, yes, in fact this does meet a written requirement and we can show repeatable testing.

Power quality and grid stability are other areas that I think will increasingly draw attention. Inverters can provide a lot of benefits in this area. All inverters now are microprocessor-controlled and can do things like active power factor correction, where they can dynamically change the power factor. Right now the UL standard requires inverters to maintain a fixed power factor. From a grid-stability standpoint, there may be reasons why we don't want to do that anymore. There may be other benefits that we can bring to the table as well.

One interesting concept is being able to work more closely with utilities on some of these issues where they could send commands to inverters in the field and modify their operating conditions. In the case of anti-islanding, we've been overly cautious about getting all the inverters off line immediately in the event of any kind of grid instability. In Europe, where PV has a higher penetration, utilities are becoming aware that when you bring all inverters off line at once, you likely make the problem worse. If you have a lot of distributed generation online and all of it suddenly dumps off line, it makes the grid stability problems worse and could lead to cascade failures. Now there are discussions about allowing the inverters to ride through a short-term disturbance, so that they would moderate voltage sag instead of immediately jumping off line.


**How the West was won** From starting SMA America at his living room coffee table, John has come full circle back to the same coffee table to work with a start-up company, SolarEdge, that he does not expect to stay small for long.

**RM**: Several external 600 Vdc disconnects are currently being marketed specifically for PV applications. Is there a need for dc disconnects listed to UL 1741? If so, how would UL 1741 need to change, and how would these new requirements differ from those in UL 98?

**JB:** Essentially, UL 1741 applies only to a disconnect sold as part of an inverter or charge controller. UL 98 applies where you have a separate disconnect. UL 98 is a general-purpose disconnect requirement, and it has some tests that are designed around disconnecting motor loads and inductive loads that are extremely severe compared to PV. For example, you have to test at a very high overload, well above your rated current, in order to pass a test that's designed around inductive loads. PV is not inductive, and it is inherently current-limited: It will deliver only a certain amount of current, no matter what. If you look at the input to an inverter, not only is it not inductive, but it's also highly capacitive.

Dissipating the arc energy is the challenge. Most breakers or big switches have arc shoots designed to dissipate arc energy as the switch opens. In the case of PV, we have two conditions: One, we are current-limited; two, a switch is used with an inverter that is disconnecting a capacitive load. There are two normal operating conditions for a dc disconnect that is operating with a grid-tied inverter: Either the inverters are not operating, so no current is flowing; or the array is operating, and the switch needs to only interrupt the current at a voltage that is the difference between open-circuit and maximum power.

UL 98 requires testing at a normal condition, which has been interpreted to be full Voc and full Isc. In reality such a test is extremely harsh, and it is not representative of in-field operating conditions. We could potentially redefine some test criteria for PV-only applications and look at this idea of switching a voltage between Voc and Vmp as being the normal operating condition. That's not a standard yet, but there have been some investigations in this area, and I would expect a standard to be coming soon.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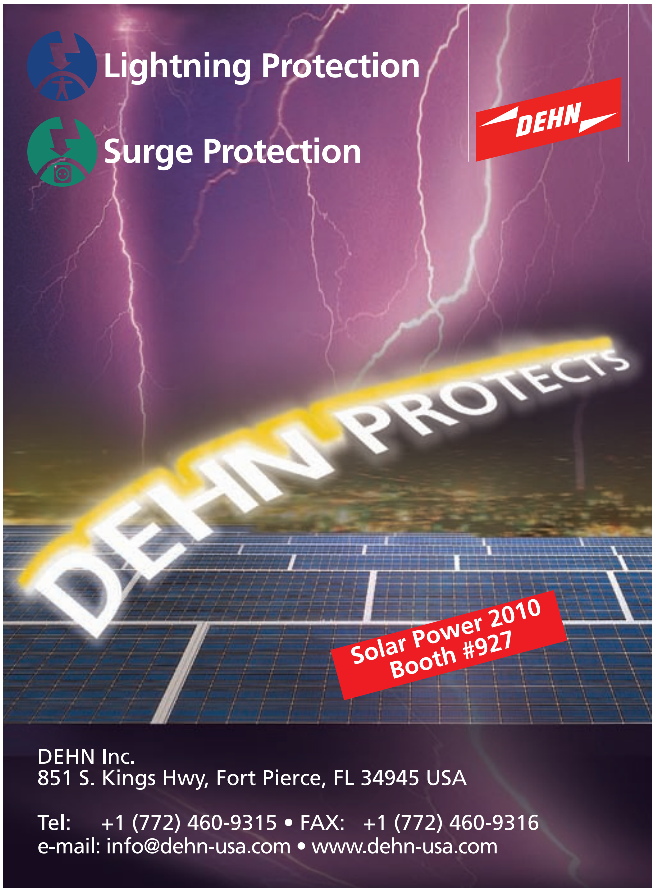
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**PV Fundamentals & Grid-Direct Design**
*Solar Energy International*
Sept 27 – Oct 1
Fayetteville
solarenergy.org

## Arizona

**Solar Training**
*Schletter, KACO new energy, & Abound Solar*
Sept 14 – Sept 16
Tucson
schletter.de/us

## California

**NABCEP/ETA Entry-Level Solar Training**
*MiraCosta College*
Sept 13 – Sept 17
Oct 18 – Oct 22
Dec 13 – Dec 17
Oceanside
mccae.org

**Technical Solar Installer Training**
*Solar University*
Sept 13 – Sept 17
Oct 11 – Oct 15
Nov 15 – Nov 19
Livermore
sunprotraining.com

**Intro to PV for Contractors**
*Solar Depot*
Sept 28
Petaluma
solardepot.com

**Intro to PV for Contractors**
*Solar Depot*
Sept 30
Sacramento
solardepot.com

**NABCEP/ETA Solar Entry Level Training**
*AmeriSkills*
Nov 15 – Nov 19
Oceanside
mccae.org

## Colorado

**NABCEP PV Installer**
*Thames Solar Electric*
Sept 13 – Sept 17
Denver
thamessolar.com

**Intro to PV for Contractors**
*Solar Depot*
Sept 17
Broomfield
solardepot.com

## Florida

**Advanced Contractor Training**
*US Solar Institute*
Sept 6 – Sept 10
Oct 4 – Oct 8
Nov 8 – Nov 12
Fort Lauderdale
ussolarinstitute.com

**PV Certification & License Fast Track**
*US Solar Institute*
Sept 6 – Sept 10
Oct 4 – Oct 8
Nov 8 – Nov 12
Dec 6 – Dec 10
Fort Lauderdale
ussolarinstitute.com

**PV Installer Training**
*Ontility & Miami Dade College*
Sept 16 – Sept 20
Miami
ontility.com

**NABCEP Certificate of Knowledge Prep**
*Solar Source Institute*
Aug 30 – Sept 3
Coconut Creek
solarsource.net

**NABCEP Certificate of Knowledge Prep**
*Solar Source Institute*
Sept 13 – Sept 17
Miami
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**NABCEP Certificate of Knowledge Prep**
*Solar Source Institute*
Sept 27 – Oct 1
Largo
solarsource.net

**NABCEP Certificate of Knowledge Prep**
*Solar Source Institute*
Nov 1 – Nov 5
Sarasota
solarsource.net

**Solar Thermal Systems**
*Solar Source Institute*
Nov 12
Sarasota
solarsource.net

**PV Design, Installation & Maintenance**
*US Solar Institute*
Dec 6 – Dec 10
Fort Lauderdale
ussolarinstitute.com

## Illinois

**PV Systems**
*Solar Training School*
Sept 13 – Sept 24
Chicago
solartrainingschool.com

## Massachusetts

**PV & Site Assessment for Installers**
*AltE U*
Sept 13 – Sept 14
Oct 18 – Oct 19
Nov 15 – Nov 16
Hudson
altestore.com

**Intermediate PV Design & Installation**
*AltE U*
Sept 15 – Sept 17
Oct 20 – Oct 22
Nov 17 – Nov 19
Hudson
altestore.com

**Advanced PV Design & Installation**
*AltE U*
Oct 25 – Oct 29
Hudson
altestore.com

## Maryland

**Technical Design & Installation Overview**
*IEC Chesapeake*
Nov 2
Elkridge
iec-chesapeake.com

**PV Advanced Business Markets & Technology**
*IEC Chesapeake*
Nov 3
Odenton
iec-chesapeake.com

**PV Design & Installation Part 1**
*IEC Chesapeake*
Dec 1
Odenton
iec-chesapeake.com

## New Jersey

**PV Intro for Contractors**
*Solar Depot*
Sept 15
Jersey City
solardepot.com

## New York

**PV Design & Installation Basics**
*Electrical Training Center of L.I.*
Sept 20 – Oct 30
Copiague
electricaltrainingcenterli.com

**PV Design & Installation Basics**
*SunDog Solar*
Oct 18 – Oct 21
Chatham
sundogsolar.net

## North Carolina

**System Installation Training**
*UL University*
Sept 13 – Sept 17
Oct 18 – Oct 22
Nov 8 – Nov 12
Research Triangle Park
uluniversity.us

CONTINUED ON PAGE 106

# TRAINING

## Pennsylvania

**PV Calculations**
*Electric Education Center*
Sept 7
Oct 5
Nov 2
Philadelphia
electriceducationcenter.com

**Entry Level PV Design & Installation**
*Electric Education Center*
Sept 20 – Sept 24
Oct 11 – Oct 15
Nov 8 – Nov 12
Philadelphia
electriceducationcenter.com

**NABCEP PV Installer Exam Prep**
*Ontility & Penn State College*
Sept 21 –Sept 22
Uniontown
ontility.com

**PV Sales Seminar**
*Electric Education Center*
Sept 29 – Sept 30
Oct 27 – Oct 28
Nov 17 – Nov 18
Philadelphia
electriceducationcenter.com

**Sunny Boy 1, 2 & Sunny Central**
*SMA Solar Academy*
Nov 2 – Nov 4
Philadelphia
sma-america.com

## Tennessee

**Sunny Boy 1, 2 & Sunny Central**
*SMA Solar Academy*
Dec 7 – Dec 9
Nashville
sma-america.com

## Texas

**PV Installer Training**
*ONtility & Cedar Valley College*
Sept 13 – Sept 17
Lancaster
ontility.com



**PV Installer Training**
*Ontility & Houston Community College*
Sept 13 – Sept 17
Houston
ontility.com

**Advanced Solar Design**
*ONtility*
Sept 18
Houston
ontility.com

**PV Sales & Marketing**
*ImagineSolar*
Sept 19
Austin
imaginesolar.com

**PV Design & Installation**
*ImagineSolar*
Sept 20 – Sept 24
Austin
imaginesolar.com

**PV Installer Training**
*ONtility & Collin College*
Oct 4 – Oct 8
Plano
ontility.com

**Electrician PV Training**
*ONtility*
Oct 19 – Oct 20
San Antonio
ontility.com

## Wisconsin

**PV Design & Installation Lab for Electricians**
*Midwest Renewable Energy Assocation*
Oct 5 – Oct 8
Oct 14 – Oct 17
Custer
the-mrea.org

**Intermediate PV**
*Midwest Renewable Energy Assocation*
Oct 9 – Oct 10
Oct 23 – Oct 24
Nov 6 – Nov 7
Custer
the-mrea.org

**Intermediate PV for Electricians**
*Midwest Renewable Energy Assocation*
Oct 12 – Oct 13
Custer
the-mrea.org

**PV Site Assessor Training**
*Midwest Renewable Energy Assocation*
Oct 18
Nov 19
Pewaukee
the-mrea.org

**Solar Water Heating Installation Lab**
*Midwest Renewable Energy Assocation*
Oct 18 – Oct 20
Oct 29 – Oct 31
Custer
the-mrea.org

**PV Design & Installation Lab**
*Midwest Renewable Energy Assocation*
Oct 25 – Oct 28
Nov 8 – Nov 11
Custer
the-mrea.org

**Solar Domestic Hot Water Systems**
*Midwest Renewable Energy Assocation*
Nov 12
Custer
the-mrea.org

**Solar Space Heating**
*Midwest Renewable Energy Assocation*
Nov 13
Custer
the-mrea.org

## Ontario, Canada

**PV Design & Installation Training**
*Ontario Solar Academy*
Sept 6 – Sept 10
Sept 20 – Sept 24
Sept 27 – Oct 1
Vaughan
solaracademy.ca

## Online

**Allied American University**
allied.edu

**Allied Schools**
training4green.com

**ONtility**
ontility.com

**Solar Energy International**
solarenergy.org

**Solar Living Institute**
solarliving.org

**Step Up Education**
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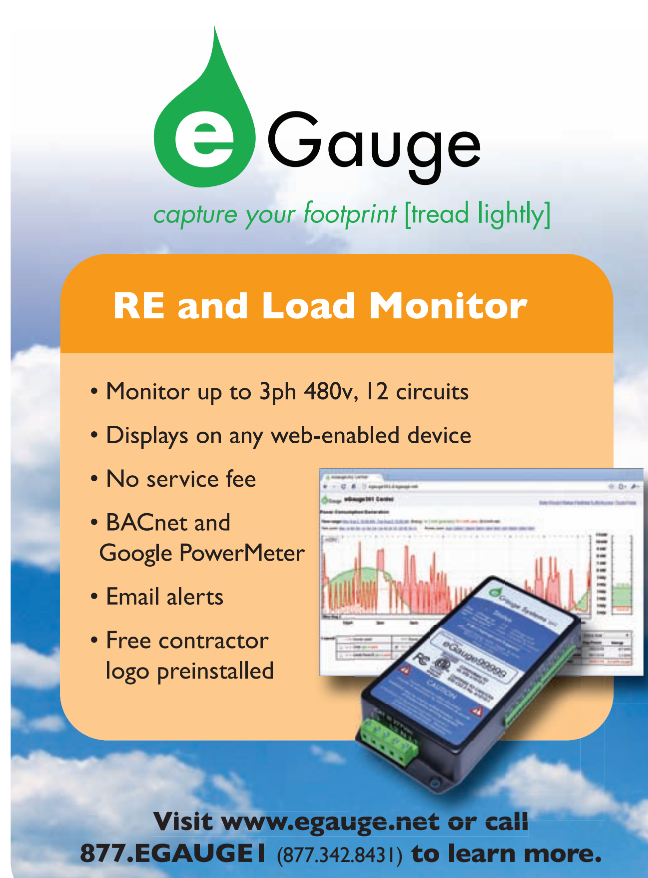
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# PROJECTS System Profiles

## COMMERCIAL GRID-DIRECT PHOTOVOLTAIC SYSTEM: National Freight Industries Solar HQ

### Overview

**DESIGNER:** Carey Ruetsch, director, Whitman, whitmanco.com

**LEAD INSTALLER:** Colin Chernowetz, senior project manager, Pro-Tech Energy Solutions, pro-techenergy.com

**DATE COMMISSIONED:** February 2010

**INSTALLATION TIME FRAME:** 120 days

**LOCATION:** Cherry Hill, NJ, 39.9°N

**AVERAGE SOLAR RESOURCE:** 3.9 kWh/m²/day

**RECORD LOW/AVERAGE HIGH TEMPERATURE:** -13°F/88°F

**ARRAY CAPACITY:** 1.32 MW

**AVERAGE ANNUAL AC PRODUCTION:** 1,400 MWh

### Equipment Specifications

**MODULES:** 6,150 Kyocera KD215GX-LPU, 215 W STC, +2.3%/-0%, 8.09 Imp, 26.6 Vmp, 8.78 Isc, 33.2 Voc

**INVERTERS:** 3-phase, 480 Vac service: one Satcon Powergate Plus PVS-250, 250 kW, 600 Vdc maximum input, 320–600 Vdc MPPT range; one Satcon Powergate Plus PVS-500, 500 kW, 600 Vdc maximum input, 320–600 Vdc MPPT range; one SMA Sunny Central 500U, 500 kW, 600 Vdc maximum input, 330–600 Vdc MPPT range

**Do you have a recent PV or thermal project we should consider for publication in *SolarPro*?**

**Email** details and photos to: projects@solarprofessional.com

Courtesy Pro-Tech Energy Solutions (4)

In February 2010, Pro-Tech Energy Solutions and Whitman were contracted by Solare Development Group on behalf of National Freight Industries Solar to implement the design, engineering and installation of a 1.32 MW PV project in Cherry Hill, New Jersey, on the company's 7-acre warehouse at its headquarters.

Direct-attached and penetrating installations were deemed inappropriate due to roof-loading issues. To surmount this engineering challenge, the companies collaborated to build a custom-designed exoskeleton on which to mount the DPW Power Rail. The exoskeleton matches the building's column spacing, which created 54 bay areas. Each 50-by-40-foot bay area consists of 8-by-8-by-¼-inch structural steel tubes that were posted down to the existing building columns. Joist girders 36 inches deep span the 40-foot length, and 28-inch–deep bar joists spaced at 5 feet on center span the 50-foot length. A total of 70 posts were flashed and weatherproofed and approved by the roofing contractor. The exoskeleton structure was built and ready for modules in only 3.5 weeks.

The exoskeleton includes a snow guard installed along the east and west edges to alleviate snow drift on the building. The roof can sustain snowdrifts along the column lines on the north and south edges. Pro-Tech contracted Englert of Perth Amboy, New Jersey, to construct the snow guard.

Further logistical challenges had to be overcome. Custom scaffolding, conveying systems and premanufactured wiring harnesses were designed to accommodate the expansive shoulder-level attachment of the modules. A 550-ton crane was required to place the steel superstructure members on top of the roof. Because paved access was available along only one side of the building,


a 300-foot jib was needed to reach the array location at the building's opposite end.  To add to the complications, local FAA clearance was required due to the crane height.

To avoid weather-related degradation, expansion and contraction of the dc wiring circuit, Pro-Tech specified that most of the wiring be run inside the warehouse ceiling. The conduit penetrated the building as it exited the combiner boxes. This technique kept nearly 80% of the electrical work out of the weather and off of the roof, but it required either working around existing sprinkler system lines and heads or relocating them.

The design called for a transformer upgrade to the facility. Public Service Electric and Gas replaced the existing 500 kVA capacity transformer with a new 1,500 kVA model. Setting the large inverters and significantly upsized transformer required extensive excavation and site work to place concrete equipment pads and a complex maze of electrical conduits.

Despite these significant challenges, the project was completed in only 120 days with minimal disruption to daily functions in the fully occupied building.

> "Although this project was challenged with design complications, we were able to stay on track because of the amazing cooperation between all the vendors, from the electrical engineers and iron workers to the mechanical engineers and racking company. Everyone demonstrated a high level of professionalism and attention to detail that made this all come together."
>
> *—John Drexinger, COO, Pro-Tech Energy Solutions*

**ARRAY, SATCON PVS-250** 15 modules per source circuit (3,225 W, 8.09 Imp, 399 Vmp, 8.78 Isc, 498 Voc), 90 circuits total (290,250 W, 728.1 Imp, 399 Vmp, 790 Isc, 498 Voc); two 23-circuit and two 22-circuit combiner boxes

**ARRAY, SATCON PVS-500** 15 modules per source circuit, 152 circuits total (490,200 W, 1,230 Imp, 399 Vmp, 1,335 Isc, 498 Voc); two 31-circuit and three 30-circuit combiner boxes

**ARRAY, SMA SC 500U** 15 modules per source circuit, 168 circuits total (541,800 W, 1,359 Imp, 399 Vmp, 1,475 Isc, 498 Voc); three 30-circuit and three 26-circuit combiner boxes

**ARRAY COMBINER:** Shoals Technologies Group with 15 A fuses

**ARRAY INSTALLATION, FLAT ROOF:** Mounted to DPW Power Rail PR240 above standing-seam steel roof, supported by custom-designed exoskeleton structure, 176° azimuth, 2° tilt

**SYSTEM MONITORING:** Pro-Tech's eXpertpower web-based Power Quality & Management solution by SATEC

# Advertiser *Index*




# COMMERCIAL SOLAR WATER HEATING SYSTEM: Alta Torre Senior Housing

## Overview

**DESIGNERS:** Justin Weil, president, SunWater Solar, sunwatersolar.com; structural engineering, Dave Helmich, D/PM Engineering, d-pminc.com; underground piping design, Jim Andrews, Thermal Pipe Systems, thermalpipesystems.com

**LEAD INSTALLER:** Jerry Saecho, foreman, SunWater Solar

**DATE COMMISSIONED:** May 2010

**INSTALLATION TIME FRAME:** 30 Days

**LOCATION:** Palo Alto, CA, 37.4°N

**SOLAR RESOURCE:** 5.4 kWh/m$^2$/day

**ANNUAL HEATING DEGREE-DAYS:** 2,849, base 65°F

**RECORD LOW TEMPERATURE:** 15°F

**COLLECTOR ARRAY AREA:** 960 sq. ft.

**AVERAGE ANNUAL PRODUCTION:** 85.5 MWh

## Equipment Specifications

**COLLECTORS:** 24 Heliodyne 410-002, 40 sq. ft. each

**HEAT EXCHANGER:** Young HEX 64 Y 2PB External

**PUMPS:** Two Grundfos UPS-50-80/2 VersaFlo, ¾-hp

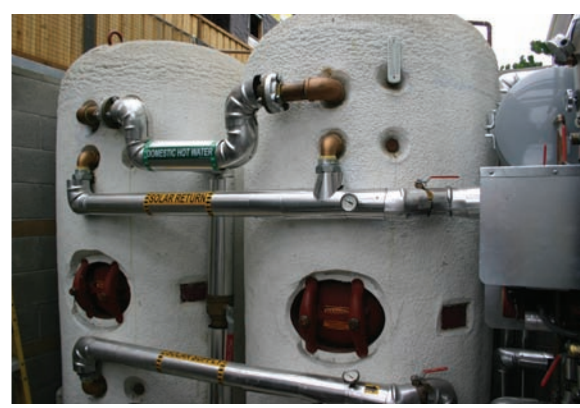
**STORAGE:** Two 534-gallon Hanson GS-42-534-V tanks, 1,068 gallons total

**CONTROLS:** Steca TR 0301 U

**FREEZE CONTOL:** Closed-loop glycol

**COLLECTOR INSTALLATION:** Custom pipe racking on low-slope roof, modified bitumen, 180° azimuth, 34° tilt

Courtesy SunWater Solar (2)

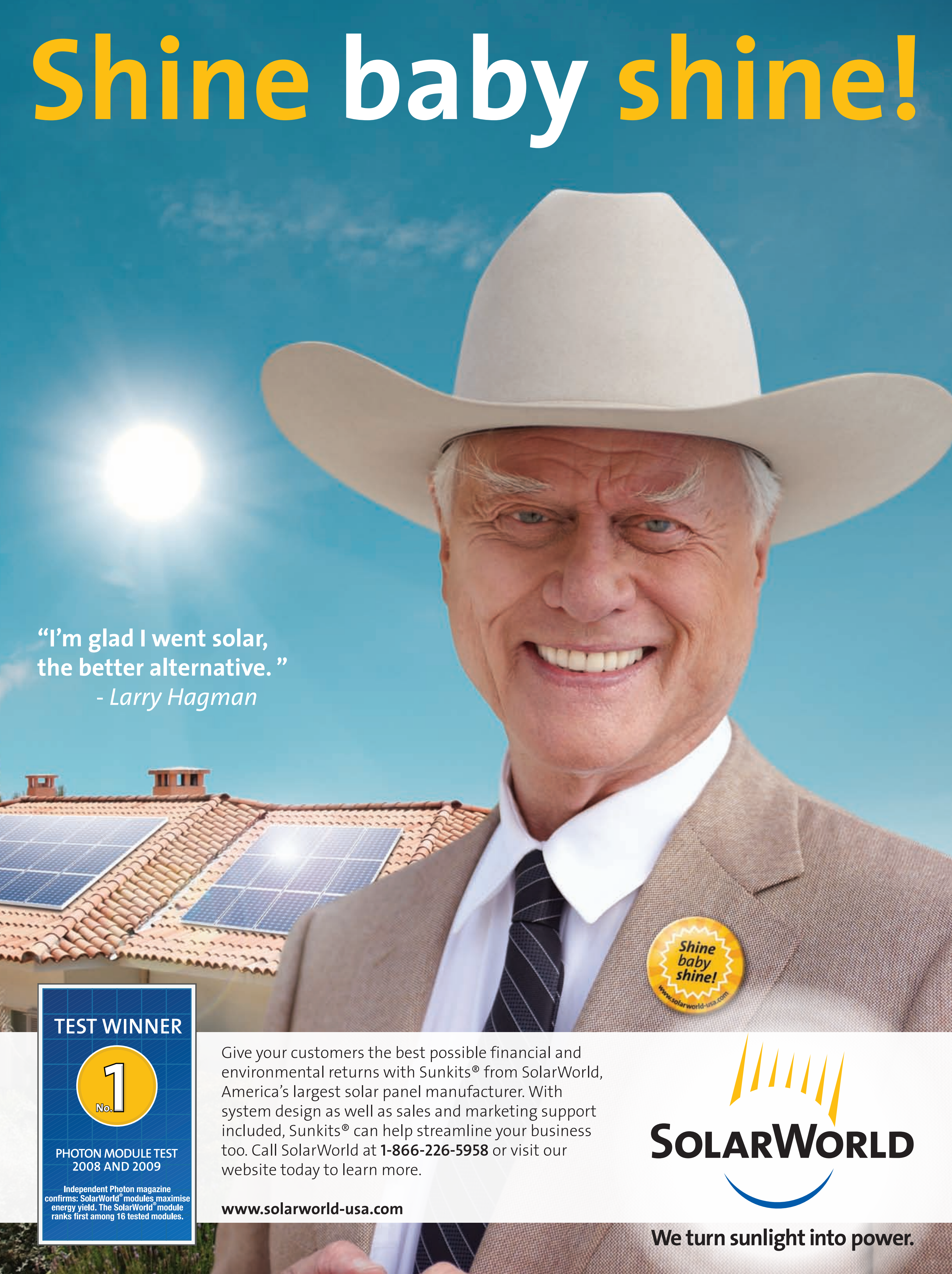


The solar thermal system at Alta Torre Senior Housing was added after the building had been designed. Unfortunately, this is an all-too-typical scenario for solar thermal installations, and it inevitably leads to "hide the big tank" meetings. In this case, the tanks could not be installed near the collectors due to space constraints. The decision was made to locate them 100 feet from the collectors in a concrete-block outbuilding that would also house a backup generator.

One of the downsides to locating the tanks away from the solar collectors is the expansion of the underground piping, which needs to be taken seriously. In thermal systems, temperatures can reach 250°F and then cool to less than 100°F with the start of the pump. We specified a preinsulated product called Copper-Core, a gasketed piping system that features integral bronze couplings with built-in expansion control. Copper-Core's couplings are not fixed joint, and the sections are not soldered. A concrete thrust block was installed at each corner in the trench to prevent excessive pipe movement.

"At the very end of the project, after we had placed our tanks and installed all of the related equipment, it was discovered that the generator was too close to the neighboring building to meet the local fire code. The architect determined that if a roof was not put on the mechanical building, the generator could stay where it was. To deal with this new plan, we gladly jacketed all of the above-ground piping and had custom metal coverings made for items such as pumps and controls."

*—Justin Weil, president, SunWater Solar*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