AC and DC Restoration for Utility Scale Photovoltaic Generating Assets

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***Abstract*— Solar SCADA systems need to take advantage of the great repetition intrinsic in solar plant design. This paper presents several key facets of a SCADA system designed specifically for utility scale solar generating assets. The presented SCADA system gathers and stores approximately 400 points per MW of installed photovoltaic generating capacity. This paper discusses both the hardware and software architecture of this SCADA system including design choices related to point types and the data system used to aggregate the information. Means and methods of data analysis are presented to enable rapid responses to forced AC and DC outages in concert with JSI's utility partners.**

***Index Terms*--Distributed Control, Power System Reliability, Power Grids, SCADA Systems, Solar Energy.**

I. Introduction

SOLAR SCADA systems share much with the SCADA systems of traditional power generation. However, because utility-scale solar systems are relatively new, there are a number of questions related to best practices for interoperating with existing utility control systems. Research data for this paper was furnished by juwi solar, Inc (JSI), which operates a staffed operations center in Boulder, Colorado. From this control center, operations personnel interface with other utility control rooms to help restore service during outages, respond to alarms from the plants, and perform system performance and analysis functions to produce performance metrics.

The paper begins with a discussion of physical monitored assets, to form an understanding of the total number of monitored points and the reasons why such points are necessary. Then, the paper will discuss the data system that reports these values to the monitoring center and plant stakeholders. The application of this data to both AC and DC restoration will be covered in the final sections of the paper. Finally, a conclusion will summarize the results and discuss future improvements currently under development to increase the usability and reliability of photovoltaic (PV) SCADA systems.

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II. Physical Plant Assets

The physical plant assets used as the basis for this paper are controlled from the JSI operations center. The nearly 50 MW of Photovoltaic (PV) capacity presented is implemented through over 700,000 individual solar modules, providing DC power through over 500 combiner boxes into 80 inverters spread out across hundreds of acres five different states. The following is not meant as a specific design example of a PV plant, but is merely presented to give the reader an appreciation for the physical size and data requirements to monitor such physically distributed assets.

Any PV generating facility can be thought of as a low-voltage distribution system acting in reverse. Located at the lowest level is the solar module, which is generally less than 100 watts in output. The modules are wired in series to achieve the desired output voltage of 600V or 1000V max. The maximum open circuit voltage is chosen based on the type of inverter and various code, land use, and contractual concerns. These strings of modules are then connected in parallel, typically in rows of 4 or 5, to aggregate a current output of 20 Amps. This collection of modules and wires is called an array.

Each array supplies power to a combiner box through a 20 Amp array feeder. The combiner box performs the function of a large wire nut, where multiple 20 Amp array feeders are aggregated into large direct-bury 500-750 kcmil cables which terminate at the inverter. The combiner box includes fusing, disconnecting means, and instrumentation to measure the finest-grained data that the SCADA system logs: the array current. A combiner box can accept up to 32 arrays, depending on the field layout and solar module technology.

Typically seven large cables from combiner boxes terminate in each inverter, the exact number determined by the array currents, physical layout, and other engineering variables. From the perspective of the SCADA system each 1.2 MW power station at a plant contains: two (2) inverters, seven (7) combiner boxes per inverter, up to 32 arrays per combiner box, resulting in 448 current measurement points and 14 combiner box bus voltage points.

At the DC terminations in the power station, the aggregate combiner box feeder current and bus voltage is measured and reported. The inverters report 50-100 points each, depending on make, model, and special design considerations. The AC output of each inverter may be monitored by separate AC metering equipment, depending on customer requirements. Power station buildings which contain the inverters and disconnecting equipment also report additional data, in the form of ambient temperature, humidity, irradiance, transformer temperature, security and door switches, differential pressure transducers, smoke/fire detectors, and weather transmitters. Future plants will include single or dual axis trackers, whose controllers will also reside in the power station buildings.

The power station AC output is at a voltage level compatible with the local distribution voltage, with each power station connected to a medium-voltage collection system. This system connects with the distribution grid at the utility POI (Point Of Interconnection). At the POI, the off-taking utility installs their revenue metering equipment. Protective relaying is supplied as required by the utility distribution engineers, including appropriate data interfaces to provide relay interfacing to their SCADA systems.

There is a significant advantage of interconnecting at distribution-level voltages, as up to approximately 20 MW can be interconnected without the need for substantial local substation equipment and transformers. Each power station is equipped with a transformer rated for the maximum output of that power station, up to 2.5 MW. As a generating plant is really a combination of interconnected small scale power station-sized plants, aggregated together at the point of interconnection, this fractal-like tessellating repeatability is leveraged in the data system architecture to make easy sense of the resulting large number of SCADA points enabling the use of standard, repeating configuration files.

Because of the large geographic distribution of the equipment, and the expense of dispatching service partners to perform service, a tremendous amount of data is logged. The SCADA system logs approximately 400 points per MW of installed capacity. This data is used to fully understand the scope of the problem before dispatching technicians to the site. This process will be covered in section IV.

III. SCADA System Software and Hardware

The following section discusses the hardware and software platform. The design of a solar SCADA system differs from other systems in the number of points and the general repeatability of all points spread over a large geographic area. The JSI SCADA system is also a true supervisory system, in that all of the equipment installed at any site operates automatically with no operator involvement. All safety and protective elements are built into the hardware installed at the site, and the system is largely used as a restorative and debugging tool. Even though it is primarily used in this manner, the system uses features in the DNP3 protocol to achieve sub-second response for real time data displays for certain channels. The operations center wants to know of breaker trips at the same time as the facility's off-taking utility, for example.

A. Plant SCADA Software Choices

At the top level of the plants is the Substation Server software platform from Subnet Solutions. This software plays the role of an old-fashioned telephone switchboard, mapping different protocols from various field equipment into an easily repeatable Distributed Network Protocol 3 (DNP3) data feed that is relayed back to the Operations Center.

On-site logging is provided for important plant performance parameters, including aggregate AC metering values and solar irradiance measurements, but there is no local data historian for all data points. The decision was made to not have a local historian at each plant out of cost, reliability, and planning reasons.

This software platform also allows extremely simple interfacing with dozens of standard protocols supported by the utility industry, allowing us to very easily support different protective equipment, meters, or inverter types at minimal cost. Presently, the system uses Modbus master and slave, DNP3 master and slave, OPC Server and Client, Local data logging, and the SEL event logging driver supplied with the software.

The use of Substation Server at each plant allows the point maps to be varied easily to meet interconnection data requirements. For example, at one plant, a DNP3 feed is supplied to the operations center, in addition to an OPC feed to the plants' owner, and a local CSV emergency data store, all from the same on-site box. The computer required to do this is an extremely low cost, temperature rated, and easy to repair unit, which keeps the plant-wide control hardware very reliable and inexpensive. A spare machine is maintained in a pre-packed box with all the site configuration files, allowing a failed site machine to be replaced within 24 hours.

Point-level debugging is performed by accessing the site master machine via a Windows Remote Desktop Protocol (RDP) connection, and then real time values can be observed locally to check the status of all field sensors. All historical data and analysis functions are performed on the SCADA master in Boulder, running on large redundant server-grade machines.

B. On-site hardware

The smallest physical resolution of data that can be monitored is the individual array feeder. This cable terminates in the combiner box at a monitoring device which relays that string current, as well as the voltage of the combiner box DC bus, back to a master radio device via mesh network. The plant SCADA master then polls that radio device via Modbus. The SCADA master then polls the plant SCADA master via DNP3, where appropriate dead-banding is applied to the data as determined by SCADA staff.

Inverter-level data originates at the power inverters, usually going through some flavor of protocol conversion device supplied by the inverter vendors to translate the proprietary inverter protocols into a protocol that is common to utilities, most likely Modbus. One particular inverter vendor insists on having this device operate as a Modbus master device, which means the plant SCADA master must be able to emulate multiple Modbus slaves in order to retrieve data from these devices.

The Author continually voices support for the various standard-groups working on 61850, Modbus, and DNP mappings for inverter manufacturers when in conversations with inverter vendors. Inverter vendors seem to be fairly shy about adopting utility protocols, but so long as reliable protocol conversion devices are available, the use of

Substation Server allows a great deal of flexibility in interfacing with these devices.

Auxiliary data, such as panel temperature, pyranometer readings, weather stations, and power station humidity and related non-electrical values are collected by various industrial analog and digital input devices, which are read via a sub-15 second Modbus poll by the plant SCADA Master. The only devices polled directly from the Boulder SCADA Master servers are the plant SCADA master machines. This enables the SCADA system to be administered by a very small staff, as, even though a large plant may have 6,000 points, there is a great deal of repetition intrinsic in solar plants that can be easily exploited.

IV. Plant Operations Overview

Having covered the basics of the SCADA system hardware and software, this section will cover general plant operations and visualizations, as well as a discussion of outage classification and response procedures.

The SCADA system supports both real time and searchable historic views. There are hundreds of alarm points defined for each plant which can be displayed on the alarm screens. After the system displays an alarm, the operator will view the plant's overview mimic screen, an example of which is shown in Fig **1**. This screen shows high-level real time data, including, at a glance, which inverter generated an alarm via a color change on the inverter identifier. Mimic indicators are also used for power supply status, breaker status, and other devices. The mimic is designed in such a way to allow the operator, at a glance, to see which machine displayed the error. By clicking on a power station, more detail can be obtained through the power station and into the feeders from the combiner boxes.

The same screens are also available via a secure web interface for approved users. The mimic in Fig **1** is for a generating asset of around 16 megawatts output that spans close to 200 acres. This plant includes a test facility which has a dual-axis tracker, seven different panel technologies on seven different inverters, and 11 main power stations interconnected via two distribution-level medium voltage pole lines.

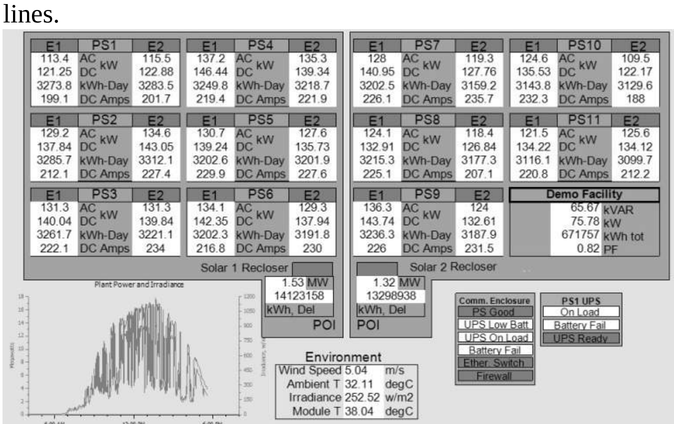


Fig 1. An example plant overview screen, showing individual inverters (E1 and E2) in each of 11 power stations, plus recloser and plant-wide status indicators. At lower left is a graph showing plant output in megawatts and solar irradiance in watts per square meter.

When an alarm occurs, which may result in the loss of generation capacity or a plant-outage, it is grouped according to several different categories worked out by operations center staff. Table **1** describes lost generation outages and common causes grouped according to the control room personnel's categories.

Forced Outage Definitions and Associated Response Times			
Outage Class	**% Offline**	**Possible Cause(s)**	**Callout Time**
Plant-Wide	50 - 100	Grid Disruption Direct Transfer Trip AC Phase/Ground Fault Local/Remote Operation of Recloser	Immediate
Major	5 - 10	Power Station Fire/Smoke Alarm Inverter Failure DC Ground Fault within Plant	Immediate
Minor	< 1	RCB Feeder Failure Disconnected/Unplugged Array Feeders	24 Hours
Array-Level	< .01	Failed Module Connectors Broken Modules	1 week - 1 month

Table 1. Forced outage definitions and corresponding callout time.

The outage class column indicates how major an alarm is, with the callout time indicating how fast the operations center will dispatch someone to the site to repair the equipment. Some alarms, including breaker trips and inverter errors, can be reset remotely depending on the installed equipment. The % offline column indicates how much of the facility is down as a result of the alarm. The reason for the break between the "50-100%" and the "5-10%" in the % offline column is that it is highly unlikely for more than one power station to be down at once during a restoration effort. Regular maintenance is scheduled as often as possible during non-generation hours, either early in the morning or late at night, so as to avoid downtime.

Generally, AC alarms require a more rapid response than DC alarms due to the modularity of the equipment. If an AC breaker opens, the entire plant goes offline until the situation is addressed. If an inverter goes down, it will only affect a fraction of the plant capacity. If a module is broken or an RCB is damaged, it still needs to be fixed, but since those errors only cause a small amount of lost generation, they can be aggregated to a single site visit to better utilize service callouts.

There are other alarms that do not necessarily result in lost generation and immediate service callouts, including communications alarms and cautionary alarms, such as high inverter temperature. There are also alarms related to weather sensors and other on-site instrumentation, which generally get aggregated into a scheduled maintenance visit rather than a service callout.

V. AC Side Restoration

Having discussed the operation of the SCADA system and the criteria for outage callouts, this section will trace through responses to actual loss of grid events. The inverters on each plant are all programmed with their own internal protective systems, such that when the plant main breaker or line recloser opens, the inverters lose synchronism and shut themselves off. None of the installed plants are capable of black start. Additionally, the inverters are programmed to re-energize in a controlled manner after the restoration of the grid connection to avoid fast watt ramp rates in the local distribution grid. Inverters can also be brought online under remote control by the operations center.

The control room has established breaker operation policies that are agreed upon with the off-taking utilities. In some cases, this includes inspecting an overhead line after a wind storm before manual operation of breaker handles. In others, it allows for fully remote restoration of service after the fault is cleared and the utility's operations center tells the operations center that it is okay to energize the equipment. The distribution operators can take the plants offline as part of their protection scheme, but only the operations center can reconnect the systems to the grid.

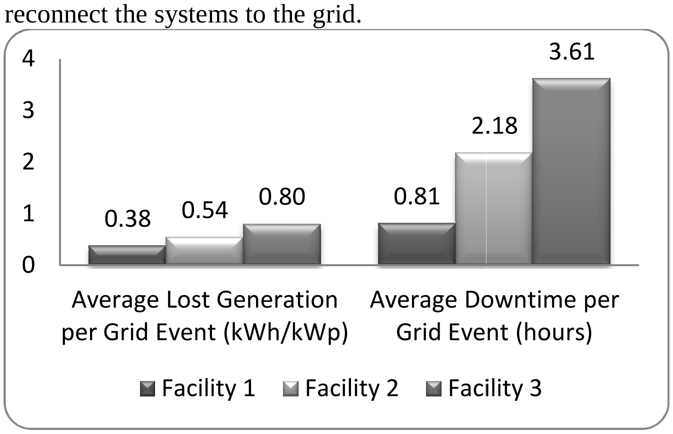


Fig 2. Grid induced outage during a one-year operational period of actual operated assets.

Fig **2** shows operational statistics of three monitored PV generating facilities ranging between 8 and 16 MW. The left set of bars indicates the average lost generation per grid event, in kilowatt-hours per kilowatt peak (kWh/kWp). At right is the average length of the outage, in hours. All of these events are classified as plant-wide immediate outages. Across all three plants, there were a total of fifteen forced outages during the period in question.

The leftmost bar, facility one, shows the lowest average downtime and the lowest lost generation per grid event. This is a facility with a remotely operable breaker which does not require line inspection prior to service restoration. The rightmost two bars, facility 2 and 3, are plants which require manual operation of the local plant breaker control handle for service restoration. The protective relays at all three sites support remote breaker trip and close.

The leftmost plant presented in Fig **2** has an average downtime per grid outage of less than one hour. This corresponds to the time it takes that utility to restore their breaker at the substation before notifying the operations center it is okay to close back in. The rightmost two plants, facility 2 and 3, have the same communications overhead, but require the additional time of a service callout and occasionally a line inspection before closing the plant breaker.

When designing the point of interconnection equipment for a facility, efforts should be made to meet the requirements of the off-taking utility. Utility-scale solar inverters are a newcomer to the protective relaying standards of most utilities. This means that both the internal inverter protection systems as well as the plant-wide protective relaying have very conservative settings. As the industry as a whole becomes more comfortable with the interaction of solar inverters at distribution level voltages and the potential for VAR support within such systems, protective settings will become looser and inverters will be no longer be expected to maintain unity power factor at all times. These features, in concert with more developments in plant control, will enable utility operators to realize the full potential of having distributed PV generating assets installed in their service territory.

VI. DC Side Restoration

The Direct Current (DC) side of a plant has its own set of considerations that is of utmost importance to the plant operators. The DC side of a PV plant includes all of the solar modules, DC Terminations, and combiner and cable systems, as well as the inverters themselves.

In Table **1**, the plant-wide outage was assigned primarily to the AC side. DC-side outages include major, minor, and array-level outage classes. A failing inverter can remove as much as 630 kW from the output of a plant, requiring a rapid response similar to an AC outage. However, solar plants also show generation capacity attrition, caused by the kinds of problems that are easy to fix but hard to see.

A large solar plant will have several hundred thousand modules, each with two connectors. Ignoring the additional problems of array feeder fusing and screw terminals inside termination cabinets, there are still many hundreds of thousands of electrical connections inside any large photovoltaic generating plant. Any system that involves hundreds of thousands of connectors which are exposed to the weather, random acts of vandalism, and curious animals will show an accumulation of randomly distributed small-scale outages with time. These randomly distributed small outages can accumulate to be a measurable amount of plant capacity loss that is considerably more labor-intensive to restore than simply replacing a fuse in an inverter.

JSI's operations center personnel have developed a series of computerized tools to aid in locating these "plugs and wires" types of generation losses. This way the precise location and type of each fault can be provided for a service callout, leading to optimal use of personnel and continued operation of the plant at peak performance. Each array is around 60 square meters in size, and the site under discussion in the section is almost 200 acres, or just over 800,000 square meters in size. For the remainder of this section, the discussion will center on procedures for finding and repairing "plugs and wires"-style faults in the solar field itself.

A. DC Side Outage Types

There are five types of DC outages that lead to power attrition: broken modules, bad connectors, shading, communications problems, and unpredictable damage. If a module or connector fails, it usually results in power losses greater than the individual module due to the series/parallel wiring of solar arrays. For example, a broken 100 watt solar module will actually result in zero current for the entire 10-module long series-connected string, removing 1kW from the plant capacity.

1) Broken Modules

Broken modules can be caused by any number of factors. Solar modules usually have a glass front, and are held down to a rigid support structure. Much design work has gone into designing support structures that both hold the modules against wind and hail forces, and allow sufficient flexibility for thermal expansion.

Even with expert engineering and proper rack installation, modules can crack and break on their own. It is infrequent, but happens often enough to justify a procedure for module replacement. Additionally, even if the mounting system works perfectly, vandalism also results in broken modules.

2) Bad connectors

Bad connectors happen because there are hundreds of thousands of connectors on a solar field, many of them crimped in the field by installation technicians. All cables are tested when the plants are brought online, but even the best-designed connectors occasionally fail. A broken connector can cause a generation loss ranging from the same as that of a broken module to an entire array, depending on where the connector has failed. This variability can be used to isolate which connector actually has failed, depending on the amount of generation lost.

3) Shading Issues

Site planning is important when constructing a solar plant, and plants are constructed to be as shade-free as possible. As the sun changes inclination throughout the year and trees grow and change with weather and time, array shading can become an issue, particularly on the periphery of a site.

4) Communications Problems

The array monitoring system involves a very large wireless mesh network consisting of several hundred pieces. The combiner boxes containing the string current sense equipment are subject to large daily temperature and humidity changes, which can cause circuit boards to fail. There are also power supply components in each box that are subject to the same surges and faults as the DC current carrying conductors, which can result in failures during fault conditions. Each combiner is equipped with surge protection equipment, but even with these precautions voltage surges and lightening events can cause problems with the mesh networking equipment.

Communications problems do not result in lost generation on their own, although they can result in the operations center not finding problems when they do exist, due to insufficient data to detect the other DC outage modes.

5) Unpredictable Damage

Unpredictable damage results from events that can't easily be fathomed. This includes animals climbing inside of conduit to eventually build nests across 1000V switch terminals, or a sudden downpour causing a mini-flood inside of a combiner box. Good site layout and engineering can do a lot to address these concerns, but Mother Nature is at times a lot more creative at problems than engineers are at solutions.

B. Procedure for finding DC side outages

The Operations Center has a continuous large stream of instantaneous array voltage and current measurements indicate near real-time current values. These values are visible on a screen that looks like Fig **3**, which shows every array supplying current to an inverter. Notice that Fig **3** has a very clear low-current measurement, R6 array #2. This image is from a clear-sky day, during maintenance with parts of that array disconnected.

Unfortunately, using instantaneous array currents to find bad arrays is not an easy task. A significant problem is that the solar irradiance generally looks like the graph in the lower left hand of the plant overview screen in Fig **1**, changing continuously. These irradiance changes hide the 10% difference in array current which may indicate a disconnected string or broken module. In addition, the update rate for array currents can vary from between one and two minutes, depending on the delay in the wireless mesh network, which makes for asynchronous updates. Taking this into account, merely comparing instantaneous array currents does not give a reliable means of finding DC generation attrition.

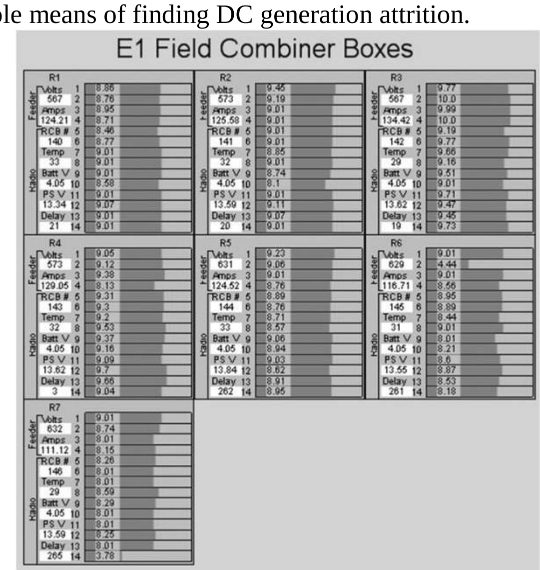


Fig 3. Display of real time array currents feeding a single 630 kW inverter. Notice visible difference on R6 Array #2.

Because of these limitations in the real-time data, under-performing arrays are located through the use of integrated Amp-Hours, using internal Amp-Hour integration and comparison algorithms. Although the bus voltage changes during the day, the entire collection of solar arrays connected to that bus are at the same potential. This means that Amp-Hour unit of measure can be used as a valid tool for finding underperforming arrays.

The Amp-Hour integration program is set up such that the operator can choose the period of time over which to integrate. This allows the operations center personnel to select a high quality integration interval, when the irradiance is good and there are no other issues that could affect the sample. An example of the output of this code is shown in Fig **4**.

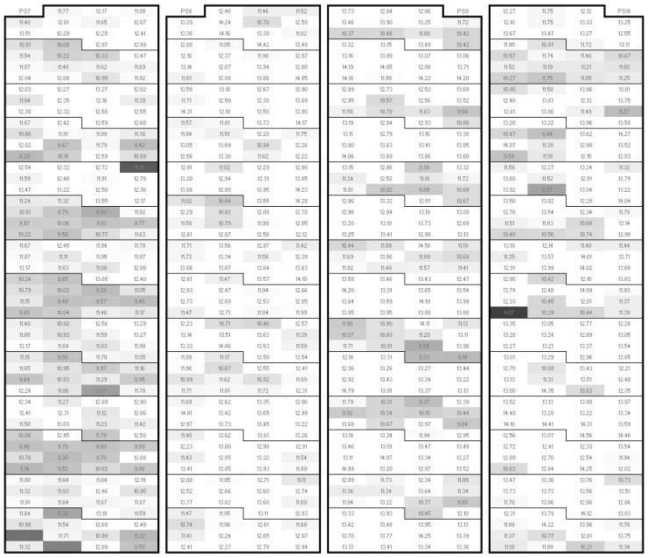
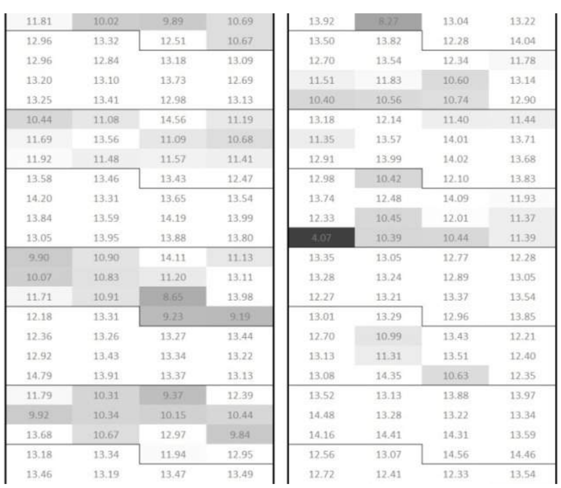


Fig 4. Example of integrated amp-hour data in graphical form from the Amp-Hour integration and comparison code.

Fig **4** only shows about 25% of the entire plant. The large rectangles are each the size of a power station, and the darker subdividing lines each indicate a single combiner box. The 14 numbers inside each combiner box corresponds to an integrated Amp-Hour value for each array within that combiner box for the period under study.

In practice, the Amp-Hour values are displayed in a color-coded manner to indicate above and below a computed average value. A glance at the figure, even in black and white, shows that there are clearly two arrays which are darker in color than the rest. It turns out that that those two darker colored arrays, each consisting of around 100 modules, in fact have a problem.

Zooming in on the right hand side of Fig **4**, which comprises parts of PS9 and PS10 at this facility, the number of amp hours for the arrays can be clearly seen in Fig **5**. Notice the dark box says "4.07", the number of amp-hours the lowest string produces.



11.81	10.02	9.89	10.69	13.92	8.27	13.04	13.22
12.96	13.32	12.51	10.67	13.50	13.82	12.28	14.04
12.96	12.84	13.18	13.09	12.70	13.54	12.34	11.78
13.20	13.10	13.73	12.69	11.51	11.83	10.60	13.14
13.25	13.41	12.98	13.13	10.40	10.56	10.74	12.90
10.44	11.08	14.56	11.19	13.18	12.14	11.40	11.44
11.69	13.56	11.09	10.68	11.35	13.57	14.01	13.71
11.92	11.48	11.57	11.41	12.91	13.99	14.02	13.68
13.58	13.46	13.43	12.47	12.98	10.42	12.10	13.83
14.20	13.31	13.65	13.54	13.74	12.48	14.09	11.93
13.84	13.59	14.19	13.99	12.33	10.45	12.01	11.37
13.05	13.95	13.88	13.80	4.07	10.39	10.44	11.39
9.90	10.90	14.11	11.13	13.35	13.05	12.77	12.28
10.07	10.83	11.20	13.11	13.28	13.24	12.89	13.05
11.71	10.91	8.65	13.98	12.27	13.21	13.37	13.54
12.18	13.31	9.23	9.19	13.01	13.29	12.96	13.85
12.36	13.26	13.27	13.44	12.70	10.99	13.43	12.21
12.92	13.43	13.34	13.22	13.13	11.31	13.51	12.40
14.79	13.91	13.37	13.13	13.08	14.35	10.63	12.35
11.79	10.31	9.37	12.39	13.52	13.13	13.88	13.97
9.92	10.34	10.15	10.44	14.48	13.28	13.22	13.34
13.68	10.67	12.97	9.84	14.16	14.41	14.31	13.59
13.18	13.34	11.94	12.95	12.56	13.07	14.56	14.46
13.46	13.19	13.47	13.49	12.72	12.41	12.33	13.54

Fig 5. Close up of the right hand, center of Fig. 4, showing 4.07 Amp-Hours as a low performing array.

Having identified the low strings, a further analysis of array data using the SCADA historical data can be used to verify the existence of a DC-side outage. An example of a historic record for the string identified above is shown in Fig **6**. The lowest line is the historical current record for the string that read 4.07 Amp-Hours, showing that over the course of the day it was tracking with the irradiance of the other arrays in the box, but was operating at half the current of its brother arrays. This observation verifies that a string on that combiner box is underperforming, and corrective action is required.

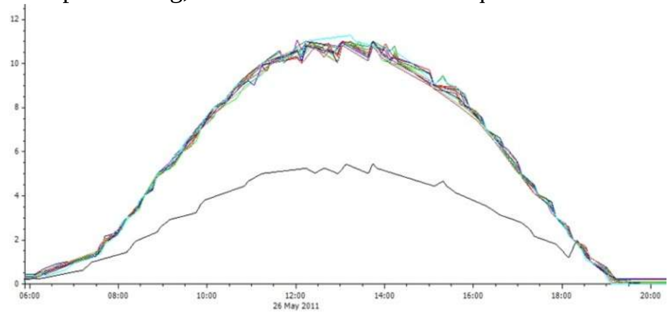


Fig 6. Detail view of array currents from block shown in Fig. 4, clearly showing 4.07 Amp-Hour string as lowest line. The x-axis is in amps, and the y-axis is time of day.

Although this data is always logged by the SCADA historian, this facility logs over three thousand individual arrays, available in displays such as that shown in Fig **3**, making conventional inspection of such curves a daunting task.

Shading of arrays also shows up in this analysis, and because the time can be specified, an early morning report will show what is shaded up until the end of sunrise, and likewise for sunset. This enables tree-trimming and other maintenance operations to be directed with speed and confidence.

The exact data set presented in Fig **4** and Fig **5** was utilized by the Author to troubleshoot and repair nine strings, resulting in returning over 12 kW of generating capacity to service. The results of service call are described in Table **2**.

Array #	Amp-Hour Reading	Problem	Solution
1	Erratic Data	Radio Module socket failure	Replace radio module socket
2	10% low	Broken module	Replaced module
3	50% low	Disconnected array feeder	Re-connected array feeder
4	10% low	Broken module	Replaced module
5	50% low	Broken connector	Replaced connectors
6	Not tracking w/ others	Suspect current sense equipment	Repaired current sensor
7	10% low	Broken module	Replaced module
8	10% low	Broken module	Replaced module
9	50% low	Broken connectors	Replaced connectors

Table 2.Array problems identified with the outlined procedure and corrected.

The return to service of 12 kW of capacity may not seem like very much on a 16 MW plant, but this was the repair of only nine arrays on one plant after a single month of reporting. In addition, it means that the SCADA system is capable of resolving a DC side outage of less than 12 kW of capacity on a 16 MW rated plant, or 0.001% of the plant's total capacity, pinpointing its location to within 55 square meters on a field of over 800,000 square meters.

This process is still under active development at JSI, and the Operation Center staff is working to expand the capabilities of the system to further automate the reporting and upkeep of the system. This technique is presently in active use at JSI, and the operations center is actively logging the results of the use of this method for finding broken modules and failed array-level conductors.

When compared to "walking the field" as a way to find broken modules, this method is clearly less work, as there are two hundred acres of solar modules installed. This process can also be executed at regular time intervals, perhaps to track the effect of a particularly vicious wind storm on a plant.

VII. Conclusions

An overview of a utility-scale Solar SCADA system was presented, including a discussion of field topology and software and hardware systems for the relay of data. Common AC side outage and restoration techniques were discussed through the presentation of actual solar field performance data. Finally, a summary of DC-side lost generation modes were presented, including a demonstration of the success of the Amp-Hour integration method of finding such issues on a 800,000 square meter utility-scale solar generating station with an accuracy of 0.001% of the plants rated DC power.

In the future, the SCADA system is growing in both complexity and features. Currently JSI is expanding its SCADA capabilities to include full bi-directional data flow for single axis trackers. This will require an upgrade of DC side algorithms to include variables relating to potential tracker alignment and operations issues. In addition, further automation is being developed to allow a back end database-level interface for automatic post processing of data, the intent being to fully automate the bad module reporting process.

In addition, by building on the base of equipment and technologies already installed, future deployments of the SCADA system will include upgraded AC and DC side metering, to allow revenue-accurate calculations of various measures of system efficiency to enable inverter characterization with the same level of accuracy as panel performance.

VIII. References

The data presented in this article are all recorded from the JSI SCADA System operations center and data historian, and represents the results of analysis by the employees of juwi solar, Inc.

The analysis techniques and applications of the technologies presented are all ideas developed within JSI.

IX. Biographies

Greg Linder (BSEE University of Illinois, 2005. MSEE, Clarkson University, 2009) grew up in the suburbs of Chicago and has been a developer, programmer, and tinkerer all his life. His experience includes work in SCADA for photovoltaic systems, embedded control, wireless mesh networking systems, solar car design, anaerobic digesters, and battery charge balancing systems. Additionally, he has worked on RF systems at Fermi National Laboratory and X-ray diffraction equipment with the University of Illinois.

He currently works for juwi solar, inc (JSI) as a SCADA Engineer and architect, tasked with interfacing utility-scale solar generating assets to utillity SCADA systems and the JSI-maintained operations center in Boulder, CO. More details are available at his personal website, http://www.linderlabs.com /glinder/.

John Tembrock (BSEE, University of Denver, 1992) is the Asset Manager for juwi solar Inc. ("JSI"). In this role, Mr. Tembrock is responsible for plant operations, maintenance and financial performance of existing solar facilities. Mr. Tembrock has 19 years experience designing and implementing industrial control and data acquisition systems. He has worked in the electric utility, semiconductor and high speed manufacturing industries. He enjoys spending time with his two young daughters and in his spare time he fine tunes his net zero energy home in the mountains of Southern Colorado.

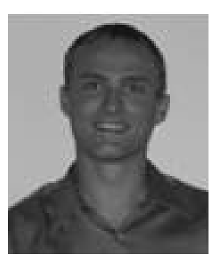
He served on the San Luis Valley Rural Electric Board of Directors in 2009 and published "Effectively Control Reverse Osmosis Systems" with Rajindar Singh in 1999.

Tony Motisi (BS University of Colorado, 2009) was born and raised in Denver, Colorado and currently resides in Boulder. He graduated summa cum laude from the University of Colorado's Department of Civil, Environmental and Architectural Engineering, with a minor in Italian language and literature. He currently works for juwi solar, inc (JSI) as an Operations Center Specialist, tasked with the monitoring and performance analysis of utility-scale solar energy generation facilities.

Electra Lamb (BS in Mechanical Engineering, Colorado School of Mines, 2009) works as an operations center specialist and contributes to design of SCADA mimics and spreadsheet analysis. She also is involved in producing regular operations center reports based on collected SCADA Data.

Dave Kubat (BAEM University of Minnesota, 2002. MS Aerospace Engineering, University of Minnesota, 2004) is originally from North Branch, Minnesota. He attended the University of Minnesota where he participated in the Solar Vehicle and Microgravity Research projects. Following graduation he joined the US Navy as an Officer on board a Nuclear Powered Submarine.

He currently works for juwi solar, inc (JSI) as the Senior Operations Center Specialist, responsible for the day-to-day plant performance and monitoring of all JSI controlled assets.



Michael Pauly (BS in Mechanical Engineering, Colorado School of Mines, 2009) is an operations center specialist as JSI, monitoring plant performance and as a first line responder to any facility outages. His background includes working as a welders' assistant and heavy machinery operator on a Bison ranch.