White paper

Integrating small solar farms to the grid: a 'smart' guide

Managing the solar flood

The construction of small solar farms is running ahead of grid integration rules in many areas, and that can be a problem for utilities. In states where there is nothing like California's trendsetting Rule 21 in place to oversee the process – and FERC rules do not apply – utilities are finding the best way to manage this solar flood is to "smarten" their transmission and distribution grids. [1]

By embracing the smart grid, utilities are not only mitigating the technical difficulties associated with integrating solar farms, they are also putting themselves in a position to benefit from the enhanced stability and reliability renewable generation can provide. On a broader level, investment in a smarter grid can directly benefit ratepayers – through the use of the most economic technologies, designs, and operating practices – while also helping states meet their renewable portfolio standard goals.

So, to help utilities jumpstart the process of integrating small solar farms, this paper will: a) identify issues their counterparts around the country have encountered; b) offer a brief guide to anticipating those issues, including questions to ask solar developers; c) provide some technical guidelines along with; d) a glimpse of the future – and indeed some cautions. One point should be emphasized up front: Any guidelines will require continual updating in the face of constant technological change, pressure to meet state and local objectives for solar development, and real-world experience as the level of solar penetration increases.

Yes, solar is different

Until very recently, when distributed generation was added to distribution systems, it was fossil-fueled, synchronous, and exhibited familiar

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California Rule 21 Guidelines

Once the interconnection study has been analyzed and modeling completed, utility engineers can begin to answer questions such as these included in California's Rule 21 [1]:

1. Is the point of common connection (PCC) on a networked secondary system?
2. Is certified equipment used?
3. Is the starting voltage drop within acceptable limits?
4. Is the transformer or secondary conductor rating exceeded?
5. Does the single-phase generator cause unacceptable imbalance?
6. Is the short circuit current contribution ratio within acceptable limits?
7. Is the short circuit interrupting capability exceeded?
8. Is the line configuration compatible with the Interconnection type?
9. Will power be exported across the PCC?
10. Is the gross rating of the generating facility 11 kVA or less?
11. Is the generating facility a net energy metering (NEM) generating facility with nameplate capacity less than or equal to 500kW?
12. Is the interconnection request for an area identified as having current or future (due to currently queued interconnection requests) grid stability concerns?
13. Is aggregate generating facility capacity on the line section less than 15% of line section peak load for all line sections bounded by automatic sectionalizing devices? The purpose of this screen is solely to determine whether the DER needs additional study and is not intended as justification for limiting the penetration of generation on a line section.

electrical characteristics. Not so with today's solar inverter-based generation. "When presented with applications for the integration of small solar farms, utility engineers are finding they must deal with an entirely new set of issues," says Howard Self, ABB's Program Manager, Smart Grid Distribution Automation, "not the least of which is whether they want to control – or just monitor – these solar facilities."

One key point: Utilities often lack control over when and where solar farms are sited. As such, distributed generators are often clustered, resulting in a higher-than-average penetration on individual distribution feeders. And as a California Energy Commission report notes, the effects of clustering relate to the distribution system's "functional connectivity," not just geographic proximity, and "therefore may not be obvious to outside observers." [2]

"This means that the connection of solar farms to the distribution grid can have a massive impact on existing equipment, especially distribution transformers – an impact that can be obscured in the rush to go green," Self said.

Minimizing the impact

The integration process generally begins when the solar developer submits an interconnection study describing the project in detail. This report will include generation and control equipment as well as interconnection points, whether such equipment is "certified," and whether the generator will connect using the utility's equipment (cables, transformers, switches, etc.) – even if that equipment is behind the meter. If the developer intends to use utility equipment, an "added-facilities" contract may be required, and that could give the utility additional control over the project. At that point, the utility begins its own due diligence. "This includes analyzing the site and modeling various generating scenarios to determine the impacts on their grid," Self said.

Once the interconnection study has been analyzed and modeling completed, utility engineers can begin to answer initial questions such as those included in California's Rule 21 (See Sidebar: California's Rule 21) .

As noted earlier, one of the first things utilities need to consider when integrating small solar farms is not just how they are going to connect to them but also how they are going to isolate them when necessary. "Many times power from renewables will go to one or more transformers before it's distributed," said Doug Voda, Medium Voltage Smart Grid Segment Leader, ABB. "It's far better to aggregate the power and then bring it onto the network through a single transformer, so it can be controlled and isolated more effectively. If you don't do it this way, you'll have a lot of issues with power factor and power quality."

Further, "if the utility can affect the choice of inverters used on small solar farms, it's better to use string inverters and aggregate power at one node," continued Voda. "String inverter technology has improved dramatically in the last four or five years."

Next, said Self, "it is critical for utility engineers to determine – among other things – whether their distribution transformers, feeders, and other equipment have sufficient capacity to accommodate the additional generation from these small solar farms."

Make no mistake, integration issues increase with the size of the solar farm. "If we're dealing with a 1 MW farm," Voda said, "the whole network is affected, and utilities should be concerned with system-wide protection schemes, coordination, SCADA, etc. But smaller farms, those adding a few kW of power to the grid, will generally not cause significant disruptions."

The ideal approach, Voda said, "is to modularize the solar farm, building it in increments, and adding string inverters as you go along to get the voltage you want."

But no matter how the solar farm is developed, one of the biggest challenges is the high learning curve utilities face when they take over. How is it going to respond to loads? How will the utility handle intermittency? How much to reduce power output and for how long? When to take or dump power? All these things need to be discussed and planned. (See Sidebar: “Questions Utility Engineers Should Ask.”)

Anticipating the new standards

IEEE’s 1547 series of standards (Figure 1) provides a set of requirements, recommended practices, and general guidance for interconnecting distributed energy resources (DERs), including small solar farms. Three-quarters of the states – along with numerous rural electric co-ops and municipal utilities – have adopted, referenced, or incorporated IEEE 1547 in their own interconnection rules. But as the National Renewable Energy Laboratory points out, advances in smart grid technology and the development of advanced DER/grid operations and controls functionalities “are surpassing the requirements in current standards and codes for DER installations and interconnection with the distribution grid.”[3]

The good news is that a full revision of IEEE Interconnection Standard 1547 is underway, including corresponding 2030 documents, which focus on communications and information technologies that provide interoperability for the integration of DER. These new standards, which are due to be issued in 2018, will establish requirements, recommended practices, and guidance for advanced DER interconnections, smart grid interoperability, and a more robust grid overall. (See Sidebar: “How the New 1547 Will Effect Distribution DER” .)

IEEE Std 1547™ (2003 and 2014 Amendment 1)
Standard for Interconnecting Distributed Resources with Electric Power Systems

- **IEEE Std P1547™ (full revision)**
  Draft Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Power Systems Interfaces
- **IEEE Std 1547.1™ (2005)**
  Standard for Conformance Tests Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems
  - **IEEE Std P1547.1a™**
    Draft Amendment 1
- **IEEE Std 1547.2™ (2008)**
  Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems
- **IEEE Std 1547.3™ (2007)**
  Guide for Monitoring Information Exchange, and Control of Distributed Resources with Electric Power Systems
- **IEEE Std 1547.4™ (2011)**
  Guide for Guide for Design, Operation, and Integration of Distributed Resources with Electric Power Systems
- **IEEE Std 1547.6™ (2011)**
  Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks
- **IEEE Std 1547.7™ (2013)**
  Guide to Conducting Distribution Impact Studies for Distributed Resource Interconnection
- **IEEE Std P1547.8™**
  Draft Recommended Practice for Establishing Methods and Precedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Std 1547-2003

Figure 1: IEEE’s 1547 Interconnection standards. [4]

Ensuring interoperability

Interoperability is the ability of grid components to communicate to one another through common protocols and standards-based application program interfaces (API). When it comes to integrating DER, new systems and components must be interoperable – not only with each other but also with legacy systems and components. Ideally, utilities should be able to integrate DER – including solar, wind, and energy storage – in varying sizes, in numerous locations, and from a variety of vendors with their advanced distribution management systems (ADMS) and supervisory control and data acquisition (SCADA) systems. But clearly, this is easier said than done. According to EPRI’s “Common Functions for Smart Inverters, Version 3” report, utilities face two slightly different issues: [4]

1. There are no common, standards-based communication protocols that allow products from multiple vendors to be integrated in a distribution system in any manageable way. And without these protocols, there is no interoperability.
2. There is no common view of the specific functionality, or services, that these products would provide.

According to EPRI, which conducted a number of DER integration demonstration projects, the second of these points is the more significant. “Although manufacturers all provided [inverters with] Smart Grid or grid-supportive functionalities, each did so in different or proprietary ways, making a system of diverse resources unmanageable.” For example, EPRI noted, every inverter maker offered VAR

Questions Utility Engineers Should Ask

These may be basic, but they are critical to smooth integration and a good place to start organizing your approach to solar integration. As outlined in a report by Georgia Power and ABB [6]:

- What are utility and installer responsibilities?
- What is the solar facility‘s maximum output?
- What is the feeder minimum load?
- Is the connecting transformer configuration: wye, delta, wye-grounded, etc.?
- What type converter will be used: Utility Interactive or Utility Independent?
- Is there other generation on the same feeder?
- What type of protective device(s) will be installed at the utility interface?
- What is the feeder reclosing sequence?
- What is the interaction with the automatic restoration scheme?
- Will protective devices be owned by the utility or the customer?
- Will a communications-aided protection scheme be necessary?
- How will proper operation of protective equipment be verified?

How the new 1547 will effect distribution DER

The full revision of 1547 is addressing distribution-level connected DER, including: [4]

- Generation and storage, including storage as a load
- Advanced functionalities of both DER and modern grid equipment
- Distribution-transmission impacts and cross harmonization of requirements
- DER supplying adequate inertia for the grid
- Microgrids
- Very high penetration of renewables and other DERs
- Intermittency and uncertainty of renewable generation
- Two-way communications, controls, and dispatchability
- Interoperability and intelligent devices integration
- Demand response and load effects
- Potential interactive effects among advanced requirements and specifications
- Introduction and incorporation of advanced evaluation and testing approaches such as enhanced modeling and simulation requirements
- Consideration and acceptance of power hardware in the loop and control hardware in the loop technology
- Potential requirements and specifications for considering evaluations of reliability and resiliency of DER-grid interconnections.

support, but lacking any standard, each provided the support in a different way. [3] So, until new standards make interoperability easier, utilities facing a flood of applications for the integration of small solar farms, are best advised to:

- Select platforms that are both: a) compatible with current systems and b) flexible enough to adapt to future improvements, including remote updating.
- Understand the autonomous functions provided in the inverters to insure they meet your immediate and future needs.
- Test the autonomous functions to insure they provide the dynamic response (i.e. voltage, watt, VAr) support necessary across your system.
- Witness-test everything before installation.
- Continually monitor their input (volt, watts, VArs) to the system after installation to insure proper performance.
- Partner with vendors who understand your system and can help you grow.

Organizing the challenges

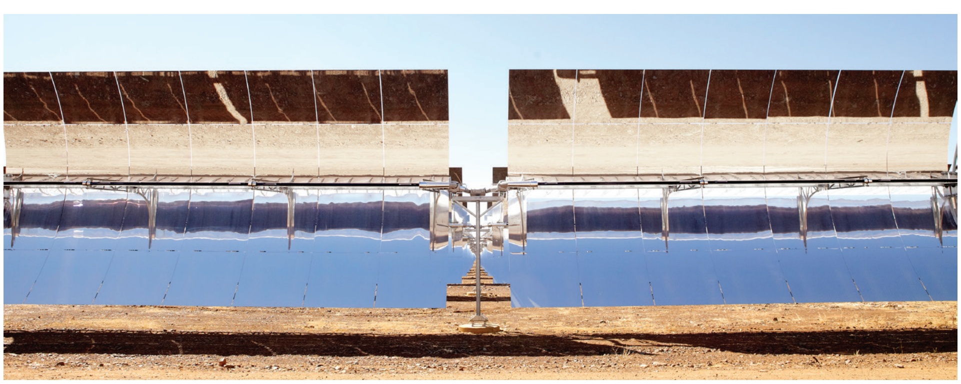
The principal challenges utilities face when integrating small solar farms fall into four general categories – 1) synchronization, 2) circuit protection, 3) modeling, and 4) communications – which may be viewed as either time-related coordination issues or distance/geography-related coordination issues. This means utilities will control a huge variety of grid components that operate under a very broad range of time constraints – from microseconds, the level at which solid-state switching devices operate, to the years it may take to bring new transmission resources online.

Time-related control issues

Balancing load and generation: In those areas of the country where utilities are facing the integration of thousands of MW of solar generation, it's clear they are also dealing with a number of issues that their systems were not designed or built to handle. Key among them, of course, is intermittency, which can affect electric demand, storage, power balancing, and synchronization. In principle, intermittency can be addressed with firming resources, including:

- Reserve generation capacity
- Dispatchable generation with high ramp rates
- Generation with regulation capability
- Dispatchable electric storage
- Electric demand response (DR)

To rely on firming generation, however, utilities require: a) real-time, minute-by-minute weather forecasts as well as the means to translate those forecasts into grid action. One way to do that is to



install an advanced distribution management system (ADMS) that not only executes weather and load forecasting but can also run demand-response (DR) programs to curtail load when necessary.

Dynamic behavior and grid stability: As noted earlier, inverters differ from conventional generators in that they produce alternating current through the rapid on/off switching of solid-state circuits, but their dynamic effect on AC systems is not well understood. As the California Energy Commission report noted, utilities would benefit from further research into the dynamic behavior of generation units on voltage and frequency stability. [2]

Distance/geography-related control issues

When non-utility-owned DER are connected to the grid – and especially when such resources are clustered – they can lead to distance/geography-related control issues, including feeder and transformer capacity, distribution circuit protection, and voltage regulation.

Hosting capacity: Certainly, the determination of hosting capacity of distribution feeders is critical to measuring their ability to support new DER integration, and that ability is a function of DER technology, size, location, and feeder topography. While utilities traditionally have determined hosting capacity "by performing detailed analyses of selected feeders and applying the results unilaterally across their system, assuming that all feeders perform similarly," that may not be entirely accurate, says EPRI. "Research has demonstrated significant variation in hosting capacity among distribution feeders, even when they appear similar in construction." [5]

Transformer capacity: Can existing transformers handle the increase in generation from DER?

Protection: As the number of solar farms on a system increases, the complexity of protection coordination and modeling increases dramatically, forcing utilities to consider innovative protection strategies. For instance, fault current produced by inverter-based generation is typically higher than that from traditional generation – but for much shorter time periods (2-4 times rated current for 0.06 – 0.25 cycles), rendering traditional protection schemes unsuitable for renewables. "While some good work has been done in this area, there seems to be not enough clarity on how PV should be modeled," a Georgia Power/ABB study concludes. [6](See Sidebar: "An Innovative Protection Scheme")

Modeling: The grid views distributed generation (DG) in terms of net load, which means that neither the utility nor the system operator may be aware of actual generation or total load at any given time. Without this information, it

is impossible to construct an accurate model of local load to either forecast future loads, including ramp rates, or to ascertain system reliability and security if the DG fails. [2]

Voltage regulation: By changing local load, DER directly affects voltage along distribution feeders, potentially sending voltage to levels outside the permissible range and, thereby, creating a need for voltage regulation. Of course, that in turn can lead to overuse of voltage regulation equipment. One caution: In some instances voltage profiles may not be seen by system operators, so enhancing situation awareness by system operators is vital. Finally, DER can create a need for reactive power (VAr) support.

Islanding: With small solar farms raising the possibility, or even probability, of islanding, utilities are finding they need to revise protection schemes. Because synchrophasors have been used successfully to control islanding and minimize load shedding, some utilities require them at the point of interconnection with every distributed generator. Accordingly, they should be considered by any utility facing the interconnection of multiple solar farms. That said, synchrophasors do require accurate time synchronization and communications, both of which are basic elements of the smart grid.

Communication issues

The integration of small solar farms generally mandates a smarter grid. "Smartness," in turn, demands a substantial increase in information flow between and among various grid components. But according to Adam Guglielmo, Director of Business Development for ABB Wireless Communication Systems, when utilities are integrating multiple solar farms, they need to look at the issue holistically, not one project, at a time.

"Utilities should look for a communication system that will meet the requirements of all the applications they will carry over time as opposed to one specific application," said Guglielmo. That, he said, requires a system that can meet a pretty high threshold in terms of:

- Low latency, i.e., the time it takes for data to travel from sender to receiver over a communication network – "This depends on the demands of the particular grid," said Guglielmo, "but we've seen requirements for sub-50 ms latency where data makes multiple hops – and requirements in substations that are even lower than that. Overall, if utility engineers plan to use a single communications infrastructure for a field area network, they should be thinking in terms of a system capable of sub-50 ms latency.
- Security.
- The ability to differentiate and properly handle different types of traffic.
- Reliability, including network uptime, longevity, and durability.

> "The beautiful thing about energy storage is that it can be so many tools on a distribution network."

Energy storage will be indispensable

Of all the issues involved in integrating small solar farms, intermittency – and the problems it creates for grid stability, reliability, and safety – is often paramount. That makes energy storage an important next step in the evolution of the smart grid. "While energy storage isn't a critical element at the grid level just yet," said Pat Hayes, ABB's Energy Storage Business Development Manager, "it is becoming increasingly important." The New York Public Service Commission takes it one step further, asserting that, increased use of load control, smart devices, and energy storage will make renewable resources more economically efficient. [7]

In the Northeast, for example, states are seeking protection from future mega-storms like Hurricane Sandy, which ravaged power systems in 2012. In California, where solar generation is king, the state has mandated that investor-owned utilities install 1.3 GW of storage by 2020.

Indeed, utilities are learning that energy storage can help with voltage and frequency control, circuit protection, ramp support for renewables, load shifting, and demand response. Further, while it's generally accepted that energy storage can be used for peak shaving, Hayes noted that it can also be used to store excess power from solar farms, or even to defer capital expenditures on generation. "The beautiful thing about energy storage," he says, "is that it can be so many tools on a distribution network."

An innovative protection scheme

The presence of distributed generation can complicate circuit protection coordination in numerous ways: 1) A fault must be isolated not only from the substation power source but also from the solar farm, which 2) will contribute a fault current until the fault is isolated; and 3) shifting fault current contributions can compromise other protective devices. As such, the CEC report suggests that utilities may want to investigate Transfer Trip schemes, an innovative way to protect circuits with DER that is similar to adaptive relaying at the transmission level. But the report also cautions that research is needed on "adapting protection schemes to safely handle power flow from multiple locations within the distribution system." [1]

Of course, the communication system, which is central to any Transfer Trip scheme, can itself present multiple challenges. As the Georgia Power study notes, leased telecommunication lines raise questions about the quality and availability of required circuits, as well as leasing and maintenance costs. A utility-owned communications system would presumably make things easier to manage, providing that communication and protection engineers are working together. While power line carrier (PLC) communication is often preferred in remote rural areas, wireless technologies offers many benefits, but they can also introduce multiple challenges related to licensing, frequency space registration, requires considerations of line-of-sight constrains, data quality, availability, reliability and security. Note: The use of wireless technologies in unlicensed or registered space is not recommended for critical applications.

Of course, achieving the greatest value from an investment in energy storage is a complex task, one that requires a comprehensive approach to operating and managing the entire distribution network. "Utilities are realizing that to maximize the value of energy storage, it has to be an integral part of their networks, not just something that's bolted on to meet a local need," added Hayes. "An energy storage management system (ESMS) that determines when a storage system should be used – and then employs it for the greatest benefit at any given time – is the key to helping utilities achieve peak performance on their distribution grid."

A smarter grid for greater control

Clearly, the pressure on utilities to integrate small solar farms is increasing at the same time society is demanding more reliable, higher-quality power for everything from advanced manufacturing to communications to data centers. To get out in front of these potentially conflicting demands, utilities and regulators are increasingly moving toward grid modernization. This trend, said Gary Rackliffe, VP, Smart Grids, North America, ABB, "is based on the fact that smart grids not only help utilities manage the impacts of DERs at the local feeder level but also at the transmission and centralized generation level."

Smart grids do this by monitoring transmission and distribution systems in real time to anticipate problems – and then reacting to resolve those issues within a fraction of a second, even isolating grid segments when necessary. Further, they will do so whether such problems are caused by equipment failure, human error, terrorist attack, or solar intermittency. But smart grids are much more than problem-solvers. "Planned and built properly," added Rackliffe, "smart grids will also optimize networks and provide utilities a new level of commercial benefit and operational control – even over small solar farms."

References

[1] Eligible wholesale generators in California must follow the state PUC's Rule 21 to interconnect distributed generation systems to electrical grid. See the "California Interconnection Guidebook" for details.

[2] "Challenges to the Integration of Renewable Resources at High System Penetration," a report for the California Energy Commission by the California Institute for Energy and Environment, University of California, principal author, Alexandra von Meier, May 2014,

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