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Sunrise in the East

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Sunrise in the East

How PJM is incorporating a large amount of solar while maintaining grid reliability

The Story in Brief
Deployment of solar power is expected to increase dramatically on the transmission grid operated by PJM Interconnection, which spans 13 Mid-Atlantic and Midwest states and the District of Columbia. While there was about 1 gigawatt of installed solar capacity on PJM's system as of the end of 2020, there were nearly 59 gigawatts of proposed solar projects in its interconnection queue. Ken Seiler, PJM's vice president for planning, spoke with *EPRI Journal* about how it is responding to the trend.

EPRI Journal: What grid reliability challenges are you concerned will begin to appear due to all the expected solar plant interconnections?


Ken Seiler

Seiler: We are inundated with renewable projects, whether they're solar, wind, or a hybrid project with batteries. Most of the proposed solar generation is on the sub-transmission system. Compared with the large central station generation paradigm of the 1950s, '60s, and '70s, the proposed generation in our queue is much closer to major load centers and much more distributed. In some cases, it's on the distribution circuits that serve loads. When these solar systems switch on and off or ramp up and down, that can lead to challenges for some customers, such as power quality impacts and transients, which are momentary voltage and current spikes from switching devices on and off.

We're also seeing concentrations of solar power in certain areas—on the scale of hundreds of megawatts—that is flowing up onto the transmission system. The transmission system has to be able to accommodate those flows so far. These solar systems are intermittent and not dispatchable, meaning we can't turn them on and off quickly. Where there are large concentrations, we need to understand the grid impacts and how to manage them. I expect that this will involve the development of additional tools and processes to study.

EJ: Are there locations of particular concern?

Seiler: We have a number of areas in our system with older transmission lines or substations. Based on the penetration of solar and resulting grid impacts in those areas, we may decide to replace some of that aging infrastructure. We are looking for synergies in certain areas with a combination of aging infrastructure, concentrations of solar, and transmission grid impacts to determine the most cost-effective upgrades needed to accommodate solar interconnections reliably.

EJ: Are there early signs of these challenges emerging?

Seiler: In some areas in the southern part of our system with large concentrations of solar connected to distribution lines, we've seen megawatts of power flowing not to the load, but up through the distribution system, through transformers, and into the sub-transmission or even the transmission system at times. We have energy management systems that continuously monitor the flows across our system. We made these observations on sunny days during light load periods like in the spring or fall. To accommodate these power flows and stay within our limits, we move dispatchable generation up and down as needed. We may take combustion turbines offline or ramp down combined-cycle gas units. But we don't have a high enough solar penetration yet to cause any significant challenges to our system.

EJ: What solutions are you considering?

Seiler: It's going to be a comprehensive set of solutions—grid modernization, enhancing the existing capabilities of the transmission system, better forecasting, new procedures, and new analytical tools. There's no silver bullet that's going to meet all our needs.

We're refining our current solar forecasting tools and analytics to help us to predict when the sun is going to be shining. This includes integrating our solar and wind forecasting tools with our weather forecasts to better refine PJM's load forecasting accuracy using neural net models.

With solar quickly ramping up and down, our control room will be prepared with new tools to monitor and control the grid and to integrate solar forecasts into our day-ahead market and real-time operating systems. We are looking at grid-enhancing technologies to help integrate solar, such as carbon core conductors to increase transfer capability on existing corridors, smart valve technologies to move power from one transmission line to another, and technologies to monitor that distribution system to a deeper level of granularity. Where we have large concentrations of wind and solar, we will need to upgrade, rebuild, and modernize transmission lines to reliably move power to the load.

As far as controlling the operations of solar plants, we can disconnect them if needed for reliability or force them offline by sending negative price signals. As we get more experience with how solar plants impact power quality for customers, we might use reactive control devices like static VAR compensators that can help provide reactive support and stability.

EJ: Who will pay for these solutions?

Seiler: This is a hot topic right now. Under our current generation interconnection process permitted by FERC [Federal Energy Regulatory Commission], we use an approach called participant funding. This means that if you're a generator, and you inject megawatts into the system and cause reliability concerns, you're going to pay to reinforce the system to mitigate those concerns. FERC is considering changing this existing paradigm so that the entities that benefit from the new generators pay instead of generators themselves. The beneficiaries include the load and customers who receive the power.

Several months ago, we started a series of workshops with our stakeholders—which include transmission owners, distribution utilities, and developers that seek to interconnect renewable energy plants to our system—to examine the different avenues by which we could pay for generation interconnection projects. We developed six different cost allocation models.

For example, under one model, a state would pay for grid upgrades that are needed to accommodate solar and wind deployment in support of the state's renewable portfolio standard. This model is called a state agreement approach. We are already using this approach with New Jersey, which wants to interconnect 7500 megawatts of offshore wind to our system. New Jersey has entered into an agreement with us to advance state public policy goals, and its ratepayers will pay for the transmission upgrades to accommodate that wind.

Another approach is called the subscriber model, in which the subscribers—meaning the companies that request solar project interconnections to a particular area impacting a particular transmission line—pay for a certain percentage—50% or 75%—of the upgrades to reinforce that line, and the beneficiaries of those projects may pay the remaining cost. We're currently vetting the six models with our stakeholders.

EJ: How can energy storage help?

Seiler: We're looking at the concept of energy storage as a transmission asset. This involves deploying storage systems on the transmission grid and configuring them to inject or absorb power to help manage power flows on transmission lines and improve reliability. This can potentially defer transmission grid infrastructure upgrades

or serve as an alternative to them. We're exploring what performance indicators—like injection duration—would be needed to reliably interconnect storage and how storage owners would be paid for the reliability services they're contributing to the transmission grid. When storage is connected to solar plants, you can significantly increase their capacity factors. That increases the generation availability to the system and makes solar more feasible to build and increase revenues in our capacity and energy markets. Solar plant operators would get paid for more megawatts.

EJ: What are the benefits of integrating solar plants?

Seiler: A grid with more generation resources that are more distributed and closer to load centers will be more capable of supplying power during peak or stressed times and may reduce the amount of additional transmission infrastructure that is needed in certain geographical areas. Integrating solar also supports the decarbonization of our system.

EJ: With more solar plants being deployed, are more long-distance transmission lines needed to help grid operators across North America share resources?

Seiler: Connecting regions with long-distance transmission can have many benefits. It can enhance the ability to share generation when needed, leverage the weather, generation, and load diversity, and support grid stability. But the process of siting a long transmission line is very labor-intensive and expensive, and the lines themselves are very expensive. There's also the issue of who's going to pay for the line. We can all sit down at a table and evaluate the need for regional transmission lines using a number of criteria, but oftentimes, if there's no driving reliability need, the stakeholders who have to pay for them ask, "Why do I have to pay for this if there's no reliability violation?"

You've got to be very surgical about where you put new lines because of the impact on landowners and on customer rates. In some areas, for example, like the Midwest, where you have large concentrations of wind, it makes a lot of sense to drive that wind through a power line to the large load centers. But for other parts of the nation, it may not make as much sense.

We already have a number of tie lines that connect PJM's system with adjacent grids to the south, north, and west. Grid operators in different regions lean on one other when they have stressed conditions like the cold weather event in the Midwest in February of 2021 or during a capacity deficiency. During the February event, PJM sent over 15,000 megawatts of power to the Midwest through our existing tie lines.

EJ: With all the new solar being proposed, PJM's interconnection study queue is much longer, stretching review timelines for new solar projects and increasing uncertainty about if and when these projects will be built and how much it will cost to interconnect them and mitigate their grid impacts. How is PJM addressing these challenges?

Seiler: This has also been a hot topic for us for about a year now. We're hearing the concerns from transmission owners, developers, and other companies that seek to interconnect solar to our system. We're working with all of our stakeholders to reform the interconnection process.

There are several fundamental issues that we're trying to address through interconnection reform. Our queue volume has quadrupled in the last three years, and we've been adding staff to help process these requests. The participant funding policy of allocating costs to the entity that causes reliability concerns has been problematic because we may have 20, 30, even 40 different solar projects connecting to the same transmission facilities—which makes it difficult economically for the first generator who causes the reliability issue to pay for the necessary transmission upgrades. The transmission owners, who do the engineering studies for the needed

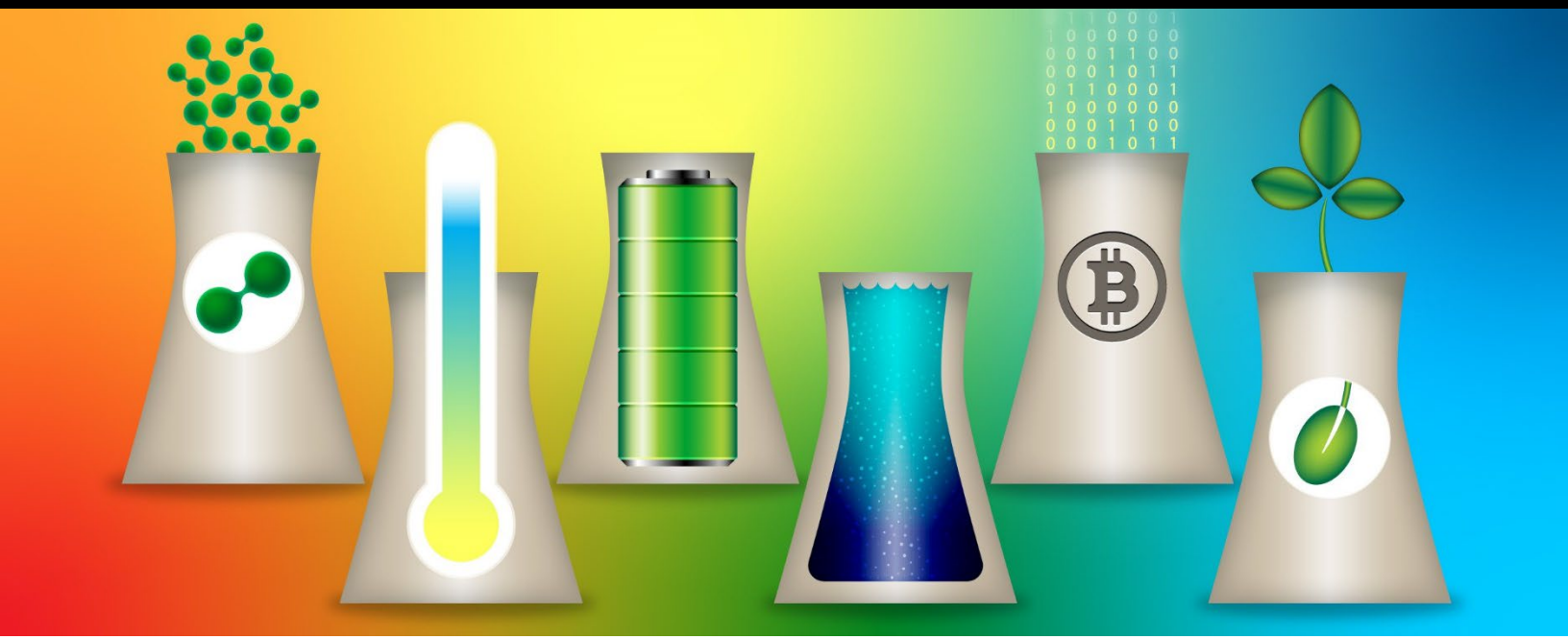
transmission facilities, are overloaded with the volume as well. And some of our developers are part of the problem. What I mean by that is that we have developers who may have the money to build two projects, and they'll submit 10 or 12 projects to us. This is overloading our queue. We need to make sure that we are getting real projects.

We've been too accommodating over the years. We've allowed multiple points of interconnection for the same project. We've allowed developers to delay their project by up to a year, sometimes even up to three years, if there are no impacts on other generators in the queue. Some of those projects are delayed because the developer is trying to sell their queue position or the project and suspends the project for a year or two. We all have a hand in this. It's going to take a village to clean this up. We have alignment with our stakeholders on two needs: cost certainty to interconnect and the time in the queue.

One change under consideration would be to prohibit developers from suspending their projects. Our suspension provisions were put in place in the late 1990s for large combined-cycle natural gas units that had to go through extensive permitting processes. A suspension option gives these projects extra time to clear these permitting hurdles. Solar and wind developers have different permitting requirements, and the obstacles are not quite as high. Hence, you don't need the suspension provisions. We're also going to increase the application cost and the cost of staying in the queue. Projects will need to pay more to stay in the queue and even to advance through the queue. Overall, our stakeholders have been very supportive of the needed changes, and we want to simplify the interconnection process. We're planning to propose changes to FERC by the end of this year.

EJ: Have the experiences of other grid operators been instructive?

Seiler: The ISOs and the RTOs across North America have frequent discussions about planning, operations, and events occurring in their systems. The most recent example is the February outages in Texas. We want to understand this and other events and see what lessons might apply to our system. We all share our experiences quite freely because we're all in this together. We want everybody to be successful. If one grid operator isn't successful, the others aren't going to be successful either. We also try to learn from what's happening in Europe, Australia, and other parts of the world. We are in the middle of a major transformation in the power industry and will need to examine and implement new tools and processes. This is the beginning of the journey, and we're all going to be learning from each other.



Nuclear Beyond Electricity

New revenue streams are needed for nuclear power to continue to drive decarbonization

By Chris Warren

Aggressive decarbonization goals are now the norm. More than 100 countries have either set or are considering targets to achieve net zero emissions. In the United States, 12 states have goals to achieve 100% renewable or net zero emission electricity generation, and around 300 large corporations have made a pledge to power 100% of their business operations with renewable energy.

To reach these ambitious targets, one of the globe's largest existing sources of carbon-free energy, nuclear power, can play a role, along with renewable resources like solar and wind.

According to the U.S. Department of Energy (DOE), nuclear energy provided over 50% of the nation's carbon-free electricity in 2020. It's a similar story around the world, with 440 reactors delivering about 10% of the world's electricity and around 30% of all low-carbon power.

Yet changes in marketplace dynamics and the economics of existing nuclear power plants make uncertain the extent to which it will be financially viable for these facilities to contribute to future decarbonization. Designed to operate continuously to generate baseload electricity delivered directly to the grid, many nuclear power plants have had to change how they operate in recent years in ways that reduce their revenues and increase the uncertainty that they will be able to continue to provide carbon-free electricity.

In particular, big increases in intermittent generation produced by wind and solar, low natural gas prices, and flat electrical load growth have all contributed to revenue declines that threaten the long-term economic viability of many nuclear power plants. For example, the utility Exelon recently announced that two nuclear power plants in Illinois would close in the fall of 2021 without state subsidies, while two others may be retired by 2023 "due to unfavorable market rules." Ultimately, a new energy bill signed in September paved the way for the plants to continue operating.

Exploring New Revenue Sources

In response to these challenges, EPRI launched the Nuclear Beyond Electricity initiative last year to identify new opportunities for existing nuclear power plants to generate revenue and continue producing carbon-free electricity. An initial report was released in March and outlines seven possibilities beyond the traditional generation of baseload electricity.

The report includes insights derived from an examination of existing EPRI projects, a literature review, and interviews with subject matter experts. For each of the potential opportunities, the report includes assessments of their readiness level, ease of implementation, and potential value. The report also identifies research and development priorities and collaborative projects with the most potential.

"This report is our initial step," said Chad Boyer, an EPRI program manager who is leading the Nuclear Beyond Electricity initiative. "We've identified 27 different opportunities in total, but we want to use this evaluation and additional outreach we are doing to really see where it makes sense to devote our research effort. From that, we are going to do a roadmap and get a list of priorities and focus on 5 or 10, some of which can be grouped together. In the past, one of the challenges to pursuing new opportunities for nuclear is a lack of coordination and different utilities and researchers could duplicate their work."

Some of the more promising opportunities identified in the report include:

Hydrogen production: News about hydrogen's role in a decarbonized world is ubiquitous these days. In May, for example, the Los Angeles Department of Water and Power (LADWP) committed to running its 4300 megawatts of fossil fuel power plants with green hydrogen by 2030. Multiple analyses estimate that green hydrogen will grow briskly in the future and be a key tool to decarbonize sectors that are hard to electrify, like shipping, manufacturing, and long-haul trucking. A report by Frost & Sullivan recently projected a 57% compound annual growth rate for the production of green hydrogen between 2019 and 2030. In addition, the DOE recently announced a "Hydrogen Shot" program, which has the goal of slashing the cost of producing clean hydrogen from $5 per kilogram today to $1 per kilogram by 2030.

Perhaps the most consequential unknown factor is the future size of the market for hydrogen. Even though green hydrogen is attracting large investments and research attention, its place in a clean energy economy remains uncertain—a question mark that is relevant to the prospects of nuclear-powered green hydrogen production.

Flexible power operations: One of the reasons existing nuclear power plants are under such financial pressure is that they historically have not adjusted their power output based on market conditions. Because they were built to operate continuously to provide baseload power, their operations and maintenance strategies were not designed to ramp generation down when large amounts of renewable generation forced prices down or ramp it up when demand spiked and renewable generation lapsed. Enhancing the capacity to operate flexibly in response to market price signals is a strategy identified in EPRI's initial research and one that member utilities have identified as a priority. In contrast to the other strategies, flexible operations would not provide a new source of revenue. However, limiting the negative effect of falling power prices can enhance the overall financial viability of a plant.

There are several different ways a nuclear plant can improve its operational flexibility, including operating at low power levels or shutting down entirely during seasons with low demand, high levels of renewable generation, or both. "The industry in the U.S. is really focusing on increasing flexibility because it can provide economic benefits relatively quickly," said Boyer. "It's not enough on its own to sustain a plant economically, but it's an approach that could be paired with other strategies to make a financial impact."

This is readily achievable. France launched an aggressive nuclear development effort after the oil crisis in the 1970s. Today, 56 reactors generate around 70% of France's electricity. For decades, French nuclear reactors have successfully provided load following and ancillary services to the grid.

Energy storage: Another reason nuclear power plants are under financial pressure is that many sell electricity at times when prices are low. The ability to store electricity produced by nuclear generators could improve their economics by allowing plant operators the flexibility to sell when it's most profitable. Integrating energy storage can also open up the possibility for nuclear plants to provide revenue-generating grid services, such as frequency regulation, voltage support, and spinning, non-spinning, and supplemental reserves.

While the potential benefits of integrating storage are significant, a lack of operational experience and storage technology costs are challenges. For example, while battery storage is experiencing cost reductions, the systems are still relatively high cost, and potential safety issues related to their integration at nuclear power plants still need to be vetted.

Water desalination: According to the United Nations, 2.2 billion people worldwide do not have access to safe drinking water, and 4.2 billion (over half the world's population) don't have adequate clean water supplies for sanitation. Although water covers over 70% of the earth's surface, only about 0.5% of the water supply is fresh and suitable for drinking, sanitation, and the growing of crops. Climate change exacerbates the challenge of fresh water access through more prevalent and intense droughts and increased risk of contamination due to elevated water temperatures.

Areas around the globe that struggle with access to fresh water, like the Middle East and the Caribbean, already use desalination technologies that remove salt from abundant supplies of ocean water to make it drinkable and suitable for other uses. But desalination requires a lot of electricity and is expensive. EPRI's analysis highlights the potential for using nuclear power plants to power desalination at times and places when the price of electricity is low, and a market exists for treated water. "Desalination is a use that has the potential to generate revenue for nuclear power plants and also has the advantage of being able to store treated water for sale later. That provides more flexibility compared to electricity markets that are more immediately time-sensitive," said Boyer. "But there is a geographic limitation to this because some places are just in more need of water than others."

Industrial uses: People and businesses around the globe rely more and more on the Internet and other

digital services for commerce and entertainment. These services are supplied by energy-intensive data centers, which consume about 1% of the world's electricity. The supply of reliable, emissions-free electricity to data centers is just one of the industrial uses nuclear power plants could meet. Others include the delivery of heat necessary for the manufacture of plastics and chemicals. In Eastern Europe, Asia, and Canada, nuclear power plants already provide steam for industrial processes, and developments in Ohio and Pennsylvania are expected to use nuclear energy to power data centers and cryptocurrency operations.

There are several potential challenges to pursuing different industrial applications. Industrial customers wanting to utilize heat produced by a nuclear power plant would need to be willing to locate near a nuclear facility and provide the infrastructure to transport the heat to their operation. Plant retrofits may also be necessary, and regulatory issues would need to be addressed. Another future possibility identified in EPRI's analysis is to use nuclear power to run direct air capture technology able to reduce carbon emissions.

Xcel Investigates Nuclear Beyond Electricity

Xcel Energy owns and operates two nuclear power plants: the Monticello Nuclear Generating Plant near Monticello, Minnesota, and the Prairie Island Nuclear Generating Plant near Red Wing, Minnesota. Together, the plants produce about 30% of Xcel's electricity to its customers in the upper Midwest.

When Patrick Burke talks about Xcel's nuclear power plants, he emphasizes the important role they need to play in meeting the utility's goal of reducing its carbon emissions 80% by 2030 and 100% by 2050. "We believe that nuclear power has to be a part of the solution to achieve those goals since it is such a large amount of our carbon-free generation currently," said Burke, who is nuclear vice president for strategy at Xcel, which is actively involved with EPRI's Nuclear Beyond Electricity initiative.

Burke said the utility's nuclear power plants need to move beyond providing just baseload power to be economically competitive enough to contribute to meeting the company's decarbonization goals. That evolution is already taking place because the plants have begun to operate more flexibly to support wind and solar generation integration. This has involved training plant personnel and adjusting processes to allow the generators to ramp up and down more quickly.

Xcel also recently began a two-year pilot project with the DOE aimed at producing hydrogen with nuclear power. Burke sees many different opportunities potentially flowing from green hydrogen production. "When you don't need the nuclear electricity, you

can divert it to hydrogen for various purposes," he said. "Here in Minnesota, there is interest in using green hydrogen to make ammonia for the agriculture industry and reduce carbon emissions in that industry. There is also interest in injecting it into natural gas generation facilities to reduce their carbon or as storage, so we have firm capacity when renewables are not producing electricity. We feel it's very important to investigate these possibilities and communicate about the importance of nuclear in decarbonization efforts."

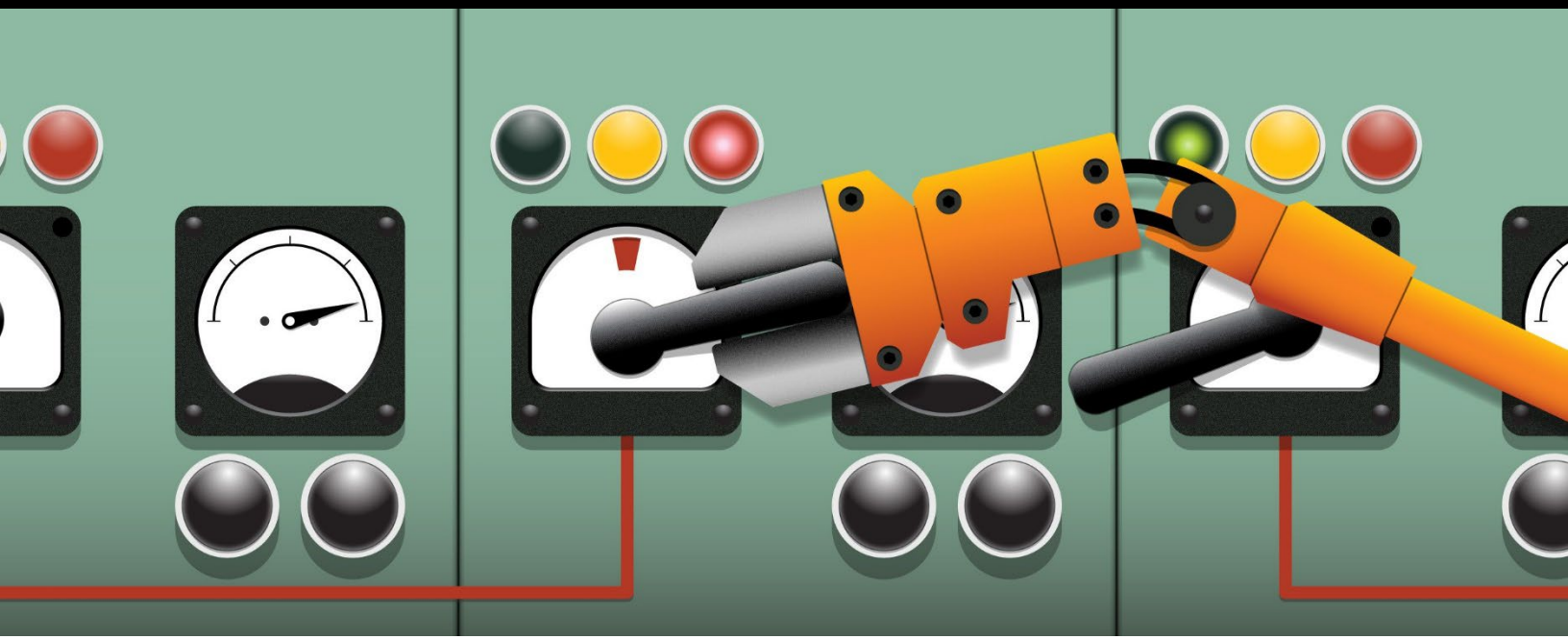
For its part, EPRI is continuing expansive research initiatives examining possible uses of nuclear power beyond the generation of baseload electricity. For example, one priority is to study the optimal ways to extract thermal or electrical energy from a nuclear plant for various uses, including hydrogen production, energy storage, and desalination. Another recently launched project will provide guidance about specific issues, including any safety issues hydrogen production at nuclear power plant sites may raise and the value of incorporating nuclear energy into energy parks.

EPRI research will also explore how small modular reactors can meet the needs of district energy users. "District energy is usually a university system, medical campus, or large corporate center where they basically produce their own steam heat for heating and sometimes cooling," said Boyer. District energy systems typically rely on natural gas, which doesn't support the zero carbon emissions targets that many schools have adopted.

"A reason why they produce their own energy and heat is they like the reliability. Solar and wind and batteries are just not going to cut it for them to provide that level of control and reliability," said Boyer. "District energy with microreactors could be that solution."

Key EPRI Technical Expert

Chad Boyer



How Low Can You Go?

As low-load operations and flexibility take on increased importance, improved plant controls and automation can help

By Chris Warren

Before Mike Seela started his current job leading Tri-State Generation and Transmission Association's efforts to improve the performance and reliability of its generation fleet, he worked as a power plant control room operator for 25 years. Seela knows from experience the tension that exists between plant operators and the utility personnel who sell electricity to energy markets.

"That tension has been around forever," said Seela, senior monitoring and diagnostics analyst for Tri-State, which provides electric generation and transmission to 45 cooperatives in Colorado, New Mexico, Nebraska, and Wyoming. "The market guys have their job providing power, and the operators have to protect their generation units and operate them safely and reliably. Those interests don't converge very often."

In recent years, it has become even more difficult to reconcile market demands with safe, reliable power plant operations—and not just for Tri-State. To help accommodate more grid-connected, intermittent renewable energy, traditional fossil fuel generation facilities designed to provide baseload power are increasingly operating at varying loads. In many instances, large coal plants have to shut down and start back up to take advantage of economic opportunities presented by the inevitable ebbs and flows of renewable generation.

"We are asking Mack trucks to operate like sports cars now," said Steve Seachman, an EPRI expert on improving plant automation and equipment health. "You're not going to push a single button and start a coal plant in minutes."

The Stresses of Starting and Stopping Baseload Plants

Quickly shutting down a large power plant in response to market conditions is technically challenging and presents significant potential risks and costs. Most operating coal plants in America

were built between 1950 and 1990 and have decades-old components.

The large temperature fluctuations accompanying startups and shutdowns put extra stress on boilers, pumps, pipes, and other metal equipment. "Temperature swings cause equipment to expand and contract," said Seachman. "The more you can minimize those temperature swings on any piece of equipment, the less stress you're putting on it and the more life you're keeping in it."

As plant operators start up or shut down a plant, they need to watch as many as ten screens in the control room to track parameters such as steam temperatures, airflow, and water levels. At the same time, they must assess whether the changes could damage equipment or lead to an outage. This can be stressful.

"These different variables are all moving together at once, and trying to remember which ones you need to keep an eye on and when can get really tricky," said Seachman.

Less Stress Using Controls and Automation to Run at Low Load

When generating and selling electricity isn't economically advantageous, a less stressful alternative to shutting down and starting up power plants is to keep them running at low load, which does not expose equipment to temperature fluctuations.

Operating at low load enables the faster ramp-ups necessary to take advantage of market opportunities: a plant at low load can reach full power in a few hours instead of a day or two when it has been completely shut down. For plant operators, this approach also avoids the stress of starting and shutting down a unit.

In 2018, EPRI started research on how to use a plant's existing distributed control and automation systems to achieve stable low loads while improving the predictability and ease of ramping generation up and down to meet demand.

Researchers identified enhancements such as adjusting controls to implement and optimize sliding pressure operation. This mode reduces the energy used to produce steam in a boiler to align with the lower energy requirements of a turbine operating at a low load. Sliding pressure operation replaces the more traditional practice of running the boiler at a constant high pressure.

Another technique identified by EPRI involves improving fuel flow control, either augmenting flow to increase a plant's load (an approach known as overfiring) or reducing flow to lower load (underfiring). Control system modifications to more precisely control underfiring can avoid potential control valve instability when reducing plant load.

EPRI also identified ways that automation can be used to decrease load to minimum levels and increase it again when demand is high. Such automation, known as sequential control, might include starting the mill where coal is pulverized and dried before it is blown into the plant's furnace. Starting a car is based on a similar type of sequence automation. "You turn the key in the ignition, and a lot of things happen automatically and in sequence—fuel enters the engine chamber, the fuel pump starts operating, oil begins to circulate, the power steering and water pump get going, and more," said Seachman.

EPRI Collaboration with Tri-State

While existing distributed control systems made by companies like Siemens and Emerson can be adjusted to enhance low-load operations, many plant operators have been hesitant to use some of these features because they automate decisions traditionally made by people. "Until recently, plant operators in the U.S. haven't had an appetite for these modifications," said Seachman. "Now there is more interest because they're looking for ways to make operations more consistent and reduce operator burden."

Seachman and other EPRI staff work directly with plants to improve low-load operation and lower minimum loads using existing controls. They visit the site, interview plant personnel, and recommend control modifications.

EPRI worked with Tri-State to assess the controls at a 450-megawatt coal plant in its generation fleet. Tri-State approached EPRI for assistance for two main reasons: it had recently installed a new control system, and the plant lacked best practices for low-load operations instead of relying on operator experience.

"We didn't have much confidence that the control system was configured optimally, and we don't have a control engineer—the plant operator with the experience to consistently make control changes," said Ron Bisbee, generation performance manager at Tri-State. "We have control technicians, but they're hesitant to dive in and make control changes because they lack the experience and formal training that control engineers have."

Tri-State implemented all six of EPRI's recommended control modifications. One was sliding pressure operation, which enabled more efficient low-load operations. Another was the automation of boiler feed pump balancing, which makes ramping more predictable and reduces operator workload.

The control modifications resulted in several improvements:

- A 25% reduction in the unit's stable minimum load (from 200 megawatts to 150 megawatts)
- An increase of more than 1% in the plant's heat rate during low-load operations
- An increase in the rate that the plant ramps up from minimum load operations

The positive results prompted Tri-State to incorporate the modifications into other units at the same power plant.

There also was an intangible benefit to the collaboration between EPRI and Tri-State. When the project started, plant operators were skeptical about whether it would deliver any value. But after they worked with EPRI and saw substantial improvements, that skepticism evaporated.

EPRI Technical Experts

Steve Seachman

Getting Flexible About Interconnection

Can allowing curtailment speed up DER growth?

By Chris Warren

Distributed energy resources (DER) are rapidly becoming an essential part of the 21st-century grid. Last year Wood Mackenzie Power & Renewables forecast that in the United States, DER investments between 2020 and 2025 would exceed $110 billion, and total DER capacity would reach 387 gigawatts by mid-decade. Solar installations and electric vehicle infrastructure are expected to be big contributors to this growth.

But while the integration of non-emitting DER can help utilities achieve aggressive decarbonization goals, it can also increase grid congestion and present other challenges to grid reliability—including the need for expensive grid upgrades.

EPRI researchers are looking at how the process of connecting DER to the grid, known as interconnection, can be enhanced to integrate DER into grid operations and planning more quickly and cost-effectively while supporting reliability and power quality.

Historically, DER interconnections use fixed capacity agreements between DER owners and utilities. These require the grid always to absorb the total DER output exported, regardless of grid conditions. The downside to this approach is that as DER penetrations rise, their output could exceed a feeder's hosting capacity, potentially leading to adverse grid impacts such as poor power quality, voltage fluctuations, and thermal overloads.

As a result, distribution grid operators conservatively consider DER interconnection requests by assuming worst-case grid conditions. The number of interconnections may be limited (or grid upgrades may be requested) to stay well below hosting capacity thresholds; this is sometimes referred to as maintaining ample headroom. While this approach supports grid reliability, it can also reduce the amount of DER connected to the grid, which can lower customer satisfaction and slow progress toward renewable energy targets.

Flexible Interconnection

As an alternative to fixed interconnection agreements, EPRI is investigating flexible agreements that enable grid operators to manage DER so that adverse grid impacts can be avoided and

more DER can be more efficiently integrated into grid operations.

"Fixed capacity interconnection agreements can sometimes trigger expensive infrastructure upgrades, which can also slow down the integration of DER," said Nadav Enbar, a program manager in EPRI's DER integration program. "By defining rules for managing DER in certain circumstances to maintain grid reliability, flexible interconnection can allow for greater grid utilization and make it faster and cheaper to interconnect DER."

While some utilities in Europe and Australia already use flexible interconnection, the approach is in its infancy in North America. Three EPRI white papers outline flexible interconnection principles. One examines rules for DER curtailment, another focuses on cost allocation mechanisms for grid upgrade costs and financial risk management, and a third examines the economic value of flexible interconnection.

The potential benefits of flexible interconnection include:

Reduced costs: By permitting DER curtailments in limited and precisely defined circumstances, flexible interconnection can help avoid expensive grid upgrades that might otherwise be needed to increase a feeder's hosting capacity or add entirely new feeders.

Faster interconnection: While conventional interconnection may require studies and grid upgrades that take years to complete, flexible interconnection can defer or avoid these delays and serve as a temporary solution to add DER. "Let's say a DER owner wants to get a project interconnected quickly but ultimately wants a fixed interconnection agreement," said Enbar. "Flexible interconnection can be a way to start generating electricity on the grid while waiting for a grid upgrade to be completed." Once the grid upgrade is complete, the flexible interconnection agreement would transition to a fixed agreement.

Increased network utilization and more renewable generation: Rapidly integrating non-emitting DER like rooftop solar using flexible interconnection can help achieve renewable energy policy objectives without making significant investments in grid infrastructure. Flexible interconnection can also help optimize the use of existing distribution grid assets by enabling more DER to be added to the grid than would be possible using fixed capacity agreements.

Rules of Curtailment

Grid operators benefit from flexible interconnection through the ability to limit DER output when there is a threat to reliability or power quality. For DER owners, it's critical to have consistency and predictability about when curtailments take place and which DER are impacted. "The curtailment rules need to be clear," said Enbar. "That includes the order in which distributed generators are curtailed and the degree to which they are curtailed."

Most utilities are expected to use one of two approaches to curtailment rules:

1. **Last in, first-out (LIFO):** DER that apply for interconnection first are curtailed last. According to Enbar, this approach gives developers more financial certainty but also makes it possible for them to game the rules by applying for interconnection long before they actually connect. This could be prevented by establishing a maximum period of time between interconnection application submission and grid connection or by basing the order of curtailment on connection dates.

2. **Pro-rata:** In this approach, the grid operator curtails all DER in an area by the same proportion. For example, 10 DER could all have their output reduced by 10% to address a grid constraint. According to Enbar, this approach can potentially enable more DER to earn a viable financial return through power exports than the LIFO approach. The downside is that as DER penetration rises, the frequency of grid congestion and curtailments may grow, and DER owners may have less confidence in the financial viability of their projects. Possible solutions include limits on connected DER capacity or curtailment thresholds beyond which no additional DER can connect.

In another possible scenario, a group of DER owners with flexible interconnection agreements could decide to pay for a grid upgrade so that they can transition to fixed interconnection agreements without curtailments. However, this may lead to unfair allocation of grid upgrade costs if the upgrade enables other DER to interconnect without contributing to those costs.

In North America, these and other questions are beginning to gain traction as utilities start to consider flexible interconnection agreements and associated pilot programs. Enbar envisions flexible interconnection playing at least an intermediary role in helping to add DER to the grid.

"We're not saying flexible interconnection should replace fixed capacity agreements," he said. "But there are circumstances in which flexible interconnection can be a bridge before the economics of grid reinforcement becomes the least cost economic approach."

EPRI is continuing to study flexible interconnection approaches in multiple ways. Current pursuits involve government as well as EPRI supplemental and base program research projects. For example, one initiative is developing a modeling methodology to assess flexibility over a wide range of system operating conditions. Another is exploring the technical and economic feasibility of actively managing solar resources to maximize energy production while minimizing the risk of violating system constraints. A third is quantifying the value of DER management systems for flexible DER interconnection.

EPRI Technical Expert

Nadav Enbar

EPRI JOURNAL

Storm of the Century

EPRI research provides tools and understanding to prepare for 100-year solar storms

By Chris Warren

People travel thousands of miles to remote spots in Iceland, Alaska, and Norway to glimpse the ethereal northern lights. Also known as the aurora borealis, the northern lights are created when a cloud of gas known as a coronal mass ejection travels from the sun's surface and collides with gaseous particles in the earth's atmosphere.

The same phenomenon that creates the spectacular northern lights can inflict real harm on the bulk power system. A geomagnetic disturbance can be triggered by a coronal mass ejection to earth, creating geomagnetically induced currents (GICs) that have been known to damage and destroy transformers and other grid components—and even trigger blackouts.

A particularly strong geomagnetic disturbance, also known as a solar storm, hit Montreal in 1989 and caused a nine-hour blackout. The event was troubling enough that it prompted regulators, policymakers, and electric utilities across North America to take action to protect the bulk power system against future solar storms.

In 2016, the Federal Energy Regulatory Commission (FERC) approved a reliability standard developed by the North American Electric Reliability Corporation (NERC). The standard requires the owners and operators of bulk power systems to assess the threat of particularly strong geomagnetic disturbances, which NERC refers to as 100-year solar storms. The standard is performance-based, meaning that it establishes what bulk power systems need to achieve—in this case, improved ability to withstand 100-year solar storms—but doesn't dictate how that objective is achieved.

As part of its approval of the reliability standard, FERC directed NERC to conduct research to improve the understanding of these solar storms. At NERC's request, EPRI led a three-year collaborative research project, the results of which were recently released.

A New Tool to Analyze Impact of Harmonics

Among the most important outcomes of this research was the development of software called GICharm that utilities can use to assess the potential impact of harmonics during a severe solar storm. "Before EPRI developed this tool, the industry had to use some rules of thumb about what equipment was most vulnerable to harmonics," said Mark Olson, manager of reliability assessments at NERC. "Now the industry can use this tool to better understand harmonics at different points on the power system."

During a severe solar storm, the relays that protect power system assets, such as capacitors and bulk power transformers, detect harmonic currents and may shut down the equipment or malfunction in one way or another. In some cases, however, the harmonics don't actually represent a threat to the equipment, and unintended operation of the relays can contribute to a blackout.

"The tool can inform decisions about which power system assets are the most vulnerable and need to be hardened—and which ones can withstand a severe solar storm without additional protection," said Bob Arritt, an EPRI expert on solar storms and their impacts on bulk power systems. "For the vulnerable transformers, you can install a device that blocks geomagnetically induced currents or make operational decisions to remove the transformer from service."

Location Matters

Another important result of the research was an improved understanding of how geography impacts the vulnerability of bulk power systems to severe solar storms.

People travel to northern locations to view the aurora borealis because that is where most solar storms are strongest and most visible. But during a 100-year solar storm, the auroral boundary extends southwards towards the equator. "When the auroral boundary pushes south, equipment within the expanded auroral boundary becomes more vulnerable," said Arritt. A storm in 1859 was believed to extend as far south as Jamaica and Cuba.

By analyzing historical and simulated geomagnetic data, EPRI researchers concluded that the auroral boundary of a 100-year solar storm could be located somewhere between 43 and 50 degrees magnetic latitude, which is similar to geographic latitude on a map. In the United States, the latitude range of 43 to 50 degrees spans from Oklahoma, North Carolina, and Tennessee in the south to just north of West Virginia. The research results mean that all regions north of 43 degrees could potentially have increased equipment vulnerability during a 100-year storm.

The research also found that local conditions can increase power system vulnerability. "Rocky regions like the Appalachian Mountains have higher soil conductivity, and that can mean greater impacts from a severe solar storm compared to other regions," said Arritt.

Expanded Transformer Modeling

The main concern about severe solar storms is that GICs could flow through transformers and cause them to overheat and fail. Protecting transformers from overheating is a challenge because the North American transmission grid includes many transformer makes and models.

EPRI developed an expanded library of thermal models used to assess overheating potential. "Before this work, there were a limited number of thermal models utilities could use," said Arritt. "We analyzed an additional 84 types of transformers that better represent the transformers on the grid. Now utilities can use our library of models to more accurately quantify the thermal response of their transformers during a 100-year solar storm."

NERC's Mark Olson says that the research results provide validation of the reliability standard as well as valuable technical information and tools to help utilities protect against severe solar storms. "Our standards establish a performance expectation for the bulk power system, but they don't tell utilities how to achieve it. The research has provided models and tools to help utilities as they assess vulnerabilities and determine mitigations so they can meet the performance expectations."

EPRI plans to use these findings and tools to assist its utility members in determining how to harden their grids against severe solar storms.

EPRI Technical Expert

Bob Arritt

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI members represent 90% of the electricity generated and delivered in the United States with international participation extending to nearly 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; Dallas, Texas; Lenox, Mass., and Washington, District of Columbia.

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