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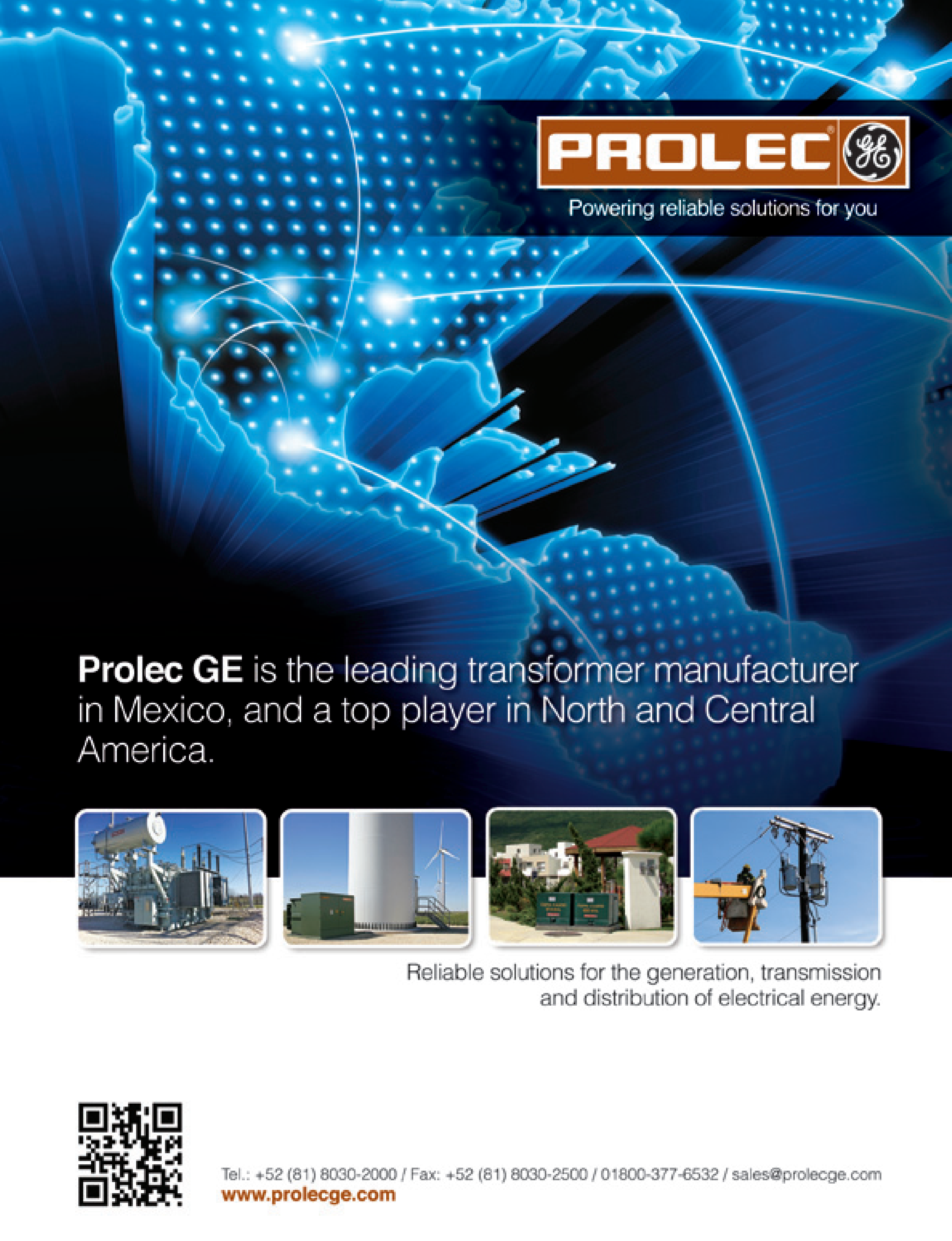
AN IN-DEPTH VIEW OF SMART GRID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POWERPOINTS

Tripping to DistribuTECH 2016

Wow, time really moves when you're having fun. Another year has passed and myself and some of the gang from the magazine have attended the 2016 DistribuTECH conference. This year it was held in Orlando, Florida, which, for me, meant flying from Toronto to the Sunshine State. The travelling is a story in itself, or should I say a comedy of errors. I seem to recall just about every commercial flight I've taken in the past five or six years has been a challenge.

When I booked this latest return flight with the airline, I thought I was getting a good deal – price-wise, that is. I had booked the econo economy class. When I checked the type of airplane I'd be on, a cold sweat rolled down my back. Just about every flight that I've been on that was using Airbus as the equipment there was something wrong or missing from the cabin. Screens didn't work, or audio crackled if it worked at all, seats didn't recline, one loo was out of order – that kind of thing.

The alarm bell should have gone off when I think I noticed the air door we were entering through was covered in green zinc chromate primer. I'm sure I saw some bondo in the seams.

As I sat down, or should I say wedged myself into my seat, one thing was painfully clear. Anyone over six feet in height should not fly this service. I am six foot three so you can image the beating my knees and legs took. I also realized that nothing in the creature comfort arena could go wrong with this Airbus because apart from the seats and windows, there was nothing, nada, rien de chose in it of use to a passenger.

It reminded me of my first car. The dash was plain metal, the steering wheel was light-weight plastic which bent every time I pried my legs underneath, the seats felt like they were filled with cotton socks, and the doors opened outward from the middle pillar so in a pinch you had air brakes. The airplane wasn't much different except that it had quite a few more seats. The seat backs were void of a TV. There was no headphone jack because there wasn't onboard entertainment of any kind. If you had a portable device like a tablet or laptop computer, you could use that to entertain yourself. They did, however offer to rent you an iPad which picked up an on-board Wi-Fi signal. No outlets for battery charging were available. The seats and seat-pitch must have barely snuck in under acceptable standards

This was also the Kindertransport. Over one-quarter of the passengers were children of all ages – all heading to Disney World with family and not all of them very happy. If it wasn't for the women behind me grousing about their nannies and schools, the flight would have been a total washout. After a couple of agonizing hours the pilot finally announced that we were on long final into Orlando. At this point, visions of the flight attendants opening the rear doors and rolling rope ladders out ran through my head. I figured it would be fitting that our cabin had to disembark five minutes before the airplane landed.

Such is the life of an editor – this one anyway.

Destination reached and no one lost an eye.

Every year there is an overarching theme that threads through DistribuTECH. Two years ago it was Big Data and last year everyone was talking up the Internet of Things (IoT) and the cloud. This year there were a few topics, the most prevalent being microgrids, distributed energy resources and distributed energy resource management systems. Advanced distribution automation (ADA) and asset health were also widely covered and discussed. With all said and done, this was another fantastic show and conference.

Microgrids

A microgrid is a localized and controlled grouping of electricity sources and loads that normally operate connected to and synchronous with the traditional centralized grid (macrogrid), but can disconnect and function autonomously as physical and/or economic conditions dictate.

A formal definition from the Conseil international des grands réseaux électriques or (CIGRÉ) states: Microgrids are electricity distribution systems containing loads and distributed energy resources, (such as distributed generators, storage devices, or controllable loads) that can be operated in a controlled, coordinated way either while connected to the main power network or while islanded. The grid connects homes, businesses and other buildings to central power sources, which allow us to use appliances, heating/cooling systems and electronics. But this interconnectedness means that when part of the grid needs to be repaired, everyone is affected.

This is where a microgrid can help. A microgrid generally operates while connected to the grid, but importantly, it can break off and operate on its own using local energy generation in times of crisis like storms or power outages, or for other reasons. It can be powered by distributed generators, batteries, and/or renewable resources like solar panels. Depending on how it's fueled and how its requirements are managed, a microgrid might run indefinitely.

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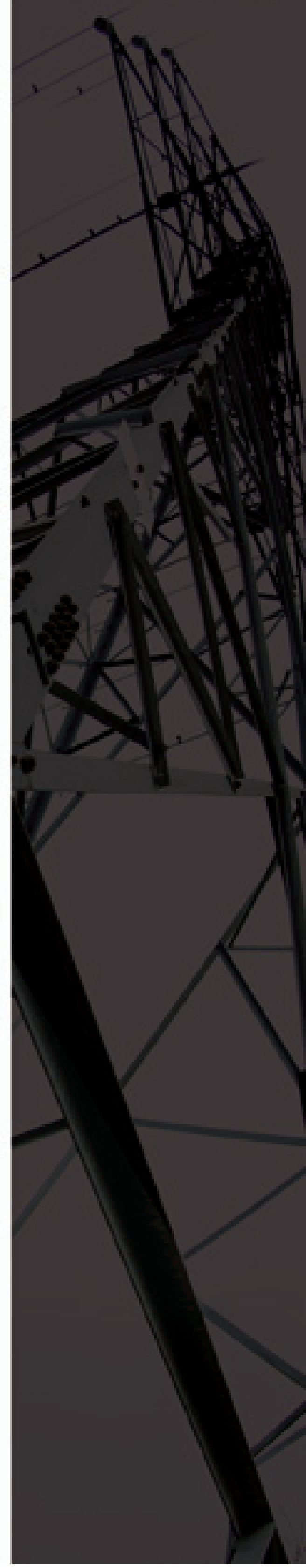
POWER POINTS



The system connects to the grid at a point of common coupling that maintains voltage at the same level as the main grid unless there is some sort of problem on the grid or other reason to disconnect. A switch can separate the microgrid from the main grid automatically or manually, and it then functions as an island. A microgrid not only provides backup for the grid in case of emergencies, but can also be used to cut costs, or connect to a local resource that is too small or unreliable for traditional grid use. Very importantly, the technology allows communities to be more energy independent and, in some cases, more environmentally friendly.

A microgrid comes in a variety of designs and sizes. They can power a single facility or a larger installation. In some cases, for example, a microgrid is part of a larger goal to create an entire district that produces the same amount of energy it consumes.

Distributed Energy Resources

Distributed energy resources (DER) are smaller power sources that can be aggregated to provide power necessary to meet regular demand. As the electricity grid continues to modernize, DER such as storage and advanced renewable technologies can help facilitate the transition to a smarter grid.

Deploying DER in a widespread, efficient and cost-effective manner requires complex integration with the existing electricity grid. Research can identify and resolve the challenges of integration, facilitating a smoother transition for the electricity industry and their customers into the next age of electricity infrastructure.

Energy storage technologies can be utilized as an effective resource to add stability, control and reliability to the electric grid. Historically, use of storage technologies has been limited by a lack of cost-effective options when compared to cheaper sources of power, like fossil fuels. However, the recent availability of lower-cost, longer-lived storage technologies as well as evolving economies for traditional transportation and grid technologies has once again made storage an attractive option.

Since wind and solar energy resources are intermittent by nature, energy storage technologies can provide necessary power during low generation periods to help keep the system stable. EPRI's research analyzes how storage technologies' costs can be decreased through manufacturing-scale experiences and lead to increased storage deployment and newer technologies that maximize opportunities for the industry and society.[1]

Integrating distributed renewable generation resources such as solar and wind into the electric grid poses a number of challenges for the electricity industry. Utilities face various generator sizes, connection points and electronic interfaces that add complexity to keeping the system stable. This includes cases of relatively high penetration of power from these resources on existing distribution systems.

These challenges can be addressed by assessing feeder impacts, inverter interface devices, analytics, studies, monitoring, special applications, and developing strategies related to future business impacts. A primary objective is to expand utility hands-on knowledge to monetize the cost and value of distributed renewable generation without reducing distribution safety, reliability, or asset utilization effectiveness.[2]

Demand response is a term that describes how distributed electricity can be managed during critical times through the use of signals. Current technology is assessing, testing, and demonstrating the application of technologies in integrated energy management control systems, linking smart thermostats, lighting controls, and other load-control technology with smart end-use devices to enable more sophisticated and effective demand response approaches in homes and buildings. Our research also offers our members an opportunity to work collaboratively with other utilities, government agencies, and manufacturers to define the requirements of end-use devices that are designed to be 'out of the box-ready,' creating the potential for dramatic operational and cost benefits.[3]

The superposition of wind power and existing load yields the crucial variable 'net load,' which is defined as the load minus the wind. Research findings and actual operator experience agree that the variability of net load exceeds that of the system when wind was not present, thus confirming the need for greater system flexibility under conditions of high wind penetration. Further, the mostly diurnal pattern of onshore wind means wind resources tend to peak when load is at its minimum. Existing commitment constraints imposed by thermoelectric baseload units means that even without transmission bottlenecks, wind power sometimes would be spilled to prevent minimum load problems. Thus, wind requires system flexibility in the form of ramping capability and lower minimum load; more flexible systems should see a lower balancing cost for wind. Many systems already have a large degree of flexibility which can be utilized to integrate wind.

Distribute Energy Resource Management Systems

Spurred by diminishing deployment costs, transforming regulatory environments, and changing consumer behavior, the past decade has seen the beginning of a fundamental shift toward the decentralization of generation. The proliferation of distributed generation is creating an undeniably profound and real effect on the utility industry, not only threatening to disrupt the present business models, but furthermore jeopardizing grid stability.

A Distributed Energy Resource Management System (DERMS) is a software-based solution that increases an operator's real-time visibility into its underlying distributed asset capabilities. Through such a system, distribution utilities will have the heightened level of control and flexibility necessary to more effectively manage the technical challenges posed by an increasingly distributed grid. While the global DERMS market is fairly nascent, regions with higher distributed and renewable generation penetration tend to have a higher degree of adoption. The DERMS market can be segmented into three distinct groups: demand response-driven, supply-driven, and a more comprehensive Mixed Asset system solution, each highly customizable on a project-by-project basis.[4]

That's all the room I have for now but I will visit ADA and Asset Health in another editorial. By the way, my return flight in econo economy BS class was no better. Glad to be back on solid ground.

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[1] *www.epri.com/Our-Work/Pages/Distributed-Electricity-Resources.aspx*
[2] Ibid
[3] Ibid
[4] *www.greentechmedia.com/distributed-energy-resource-management-systems*

INDUSTRY NEWS

New York Power Authority Wins Award for Assessing Social Cost of Carbon Emissions

March, 2016

The New York Power Authority has received an Electric Power Research Institute Technology Transfer award for research that contributes to the understanding of the social cost of carbon emissions.

John Kahabka, NYPA vice president of Environmental Health and Safety and a resident of Newburgh, led both efforts on behalf of NYPA and accepted the awards earlier this month.

Kahabka participated in an analysis of the methodologies used by the U.S. Environmental Protection Agency for determining the social costs of carbon dioxide emissions. The EPRI team examined the modeling undertaken by federal agencies and identified several flaws. The team presented its findings at the climate change summit meetings last year in Paris.

Kahabka also received a second Technology Transfer award for his leadership and support of EPRI's Occupational Health and Safety Research Conference held last May.

"We are proud of NYPA's contribution to industry research generally, but particularly in the important areas of climate change and worker safety," said Gil C. Quiniones, NYPA president and CEO, who also serves as EPRI chairman.

EPRI presented its 2015 Technology Transfer Awards for Environment R&D to 47 individuals representing 24 electric companies on March 1.

"The 2015 Technology Transfer Award winners made significant achievements in applying EPRI research results, or acting as champions of EPRI research programs," said Anda Ray, senior vice president, energy, environment and external relations and chief sustainability officer at EPRI. "The collaboration of these teams and individuals enables the industry to continuously improve and enhance power delivery for the benefit of their stakeholders and society."

Utilities Experience Growing Pains in Widespread Adoption of Mobile Websites and Apps, Says J.D. Power

March, 2016

Utilities are going mobile, with all large electric and most large natural gas utilities now providing a mobile-enabled website or app; however, many utilities still struggle with website design and functionality, failing to provide content that is easy to access via mobile, according to the J.D. Power 2016 Utility Website Evaluation StudySM (UWES) released today (3/17).

The study, now in its fifth year, is based on a combined ranking of evaluations collected across mobile websites/apps and desktop/laptop/tablet (desktop) devices. The study explores how easy it is to use a utility's website by examining 12 tasks based on the type of utility: set up an online account; account log in; view consumption history; review account information; make a payment; research energy saving information; update service; report outages; view outages; locate contact information; perform account and profile maintenance; and locate gas leak information.

The study finds that the percentage of large utilities offering a mobile channel for their customers either through a mobile-enabled website or mobile app has increased dramatically to 92% in 2016 from 72% in 2014, and satisfaction with ease of use has improved to 409 (on a 500-point scale) from 405. Of the 65 U.S. electric and natural gas utilities included in the study, 59 of them currently offer a mobile solution. While many of the utilities have adapted to responsive design for their website one where the Web content adjusts to various screen sizes customers are experiencing problems accessing content due to design and functionality challenges with the site.

Based on findings of J.D. Power's utility syndicated studies, 30% of customers in the 2016 Electric Utility Residential Customer Satisfaction Study indicate experiencing one or more issues when using their mobile phone with their utility's website or app. Among customers experiencing one or more issues, 16% indicate that the information was not accessible or froze, and 12% indicate that the information was not provided on electric utility sites and 18% say the same about natural gas mobile sites or apps. The volume of problems experienced by customers is most likely driven by the lack of content or the inability of customers to find content, as opposed to issues with the website's technology.

"Many utilities have deployed responsive design technology on their mobile websites to deliver content that automatically fits on the various screen sizes of mobile devices," said Andrew Heath, senior director of the utility and infrastructure practice at J.D. Power. "However, it's not enough to just implement responsive design without also designing the website content customers will ultimately experience on their mobile device."

According to Heath, while the UWES evaluates the most popular transactions on a utility website, "utilities need to understand that content is king and customers expect to conduct the same interactions on their mobile device as they do using a desktop."

Following are some of the key findings of the 2016 study:

- Ease of Use Performance: Among the utility companies included in the study, AEP, Alabama Power and First Energy perform particularly well in overall ease of use of utility websites.
- Focus on Account Access: Satisfaction scores for the review account information task is a strong predictor of satisfaction among customers with electronic billing in the residential electric and gas syndicated studies.
- Utility Website Used for Emergency Information: A growing number of customers use a utility website in emergency situations to report an outage, view current outage information or find details of a gas leak. However, it takes more than two minutes, on average, to find the relevant information on the site.
- Likelihood to Reuse Utility Website: Among study brands in the top quartile (scores of 426-441), 56% of customers say they "definitely will" return to the utility website, compared with 50% among brands in the bottom quartile (scores of 357-405).

The 2016 Utility Website Evaluation Study (UWES) is based on evaluations from more than 15,100 electric and/or gas residential customers, with 5,636 of these customers providing feedback about their online experience using a mobile device. The 65 largest U.S. electric and/or gas companies are included in the study, which was fielded from December 7, 2015, through January 21, 2016.

The study provides utility companies with an objective assessment of the usability of their website; establishes performance benchmarks; provides improvement recommendations; and identifies best practices across the industry. Ease of use is calculated on a 500-point scale.

For more information about the 2016 Utility Website Evaluation Study (UWES), visit *http://www.jdpower.com/resource/us-utility-website-evaluation-study*

Reliant's "Power on the Go" Plan Keeps Texans Connected Wherever They Are

March, 2016

For more than a decade, Reliant has offered plans and services as unique as Texas. In continuing the Texan spirit of independence, the new Reliant Power on the Go plan brings customers a fixed-rate plan for home electricity, plus a portable power component via a free solar charging kit. The plan is designed to give Texans a convenient way to power small electronic devices when they're away from outlets.

The complimentary $400-value portable solar kit includes a lightweight power pack with 5200mAh battery, durable 13-watt foldable solar panel and power inverter to keep tablets, phones and most laptops powered anytime, anywhere. The power pack's capacity is enough to charge a phone full up to five times. Customers also receive the benefit of 24/7 customer service and support online or by phone, access to energy-savings tools and more.

"Texans lead very unique lives, but one thing we have in common is that we are busy at home, at work and on the go, and that's why Reliant's promise is to keep our customers powered wherever they are," said Elizabeth Killinger, president of NRG Retail and Reliant. "The new Reliant Power on the Go plan is our latest step toward providing options that fit our customers' lifestyles. Along with affordable home electricity service, we're all about meeting your tremendous need these days for power, so you don't miss out on life's most important and fun moments."

The Power on the Go plan is another example of how Reliant is more than "just" an electricity company - Reliant takes seriously its responsibility of providing new, innovative solutions that enable today's mobile-driven world. To help get the word out on this exciting offer, Reliant recently launched its "One of a Kind" campaign to showcase different plans and services that cater to Texans from all walks of life.

"As a fourth-generation Texan, I am excited about our One of a Kind' campaign. It is a promise that we appreciate what makes Texas great and Texans unique, and that consumers can rely on us to provide affordable and convenient electricity and related services that meet their specific needs," said Killinger. "Reliant is all about being your hometown power company that anticipates your power essentials, provides you greater insight and control over your electricity, advises on how to be more energy efficient and delivers you convenient power solutions at home, at work and on-the-go. We're committed to putting our customers first and making a difference in the communities where we live and work."

JCP&L Begins Construction on New Transmission Project in Monmouth County to Enhance Reliability for Customers

March, 2016

Jersey Central Power & Light (JCP&L) has started construction on a new substation project in Monmouth County to help enhance service reliability for more than 180,000 customers in Colts Neck, Howell, Neptune, Tinton Falls and Wall.

The project includes building a new 16-mile, 230-kilovolt (kV) transmission line along existing right-of-way with steel pole construction to connect JCP&L substations in Howell and Neptune. In addition, an existing 230-kV transmission line connecting substations in Colts Neck and Neptune will be rebuilt using steel poles instead of the current wooden structures.

Ultimately, the work also will include installing new equipment in these substations, including circuit breakers and remote-control communications equipment. The overall cost of the project is $124 million, with about $97 million being spent in 2016.

"This transmission project will make our system in Monmouth County more resilient and help meet the growing demand for electricity in the region," said Jim Fakult, president of JCP&L. "Along with the greater redundancies provided by the new transmission line, the high-tech substation devices we plan to install will give us the ability to operate the system remotely, automatically resetting the equipment instead of having to send a line crew to investigate the cause of the problem."

The new transmission line is expected to be completed and in-service by June 2017.

The project is part of JCP&L's multi-year, $250 million "Energizing the Future" transmission system reliability enhancement program.

PSEG Long Island Continues to Expand FEMA Reliability Projects in Southold

March, 2016

PSEG Long Island customers in Southold will see more crews in their neighborhood this spring as an additional circuit is being added to ongoing FEMA reliability work. This circuit will be the ninth project in the Town of Southold, where FEMA funded work began in April 2015 to improve the reliability and resiliency of the electric grid for Southold residents.

PSEG Long Island licensed and approved contractors will be working on this route for approximately five months. Work will include replacing existing wires, installing new and more durable poles and installing or replacing switching equipment to help reduce the number of customers affected by an outage.

"Adding an additional circuit in the Town of Southold makes it one of the most active work areas for FEMA funded reliability work," said John O'Connell, PSEG Long Island vice president of transmission and distribution operations. "With this additional work, an increasing number of Southold residents will have the best-in-class system reliability that PSEG Long Island is continually striving to deliver."

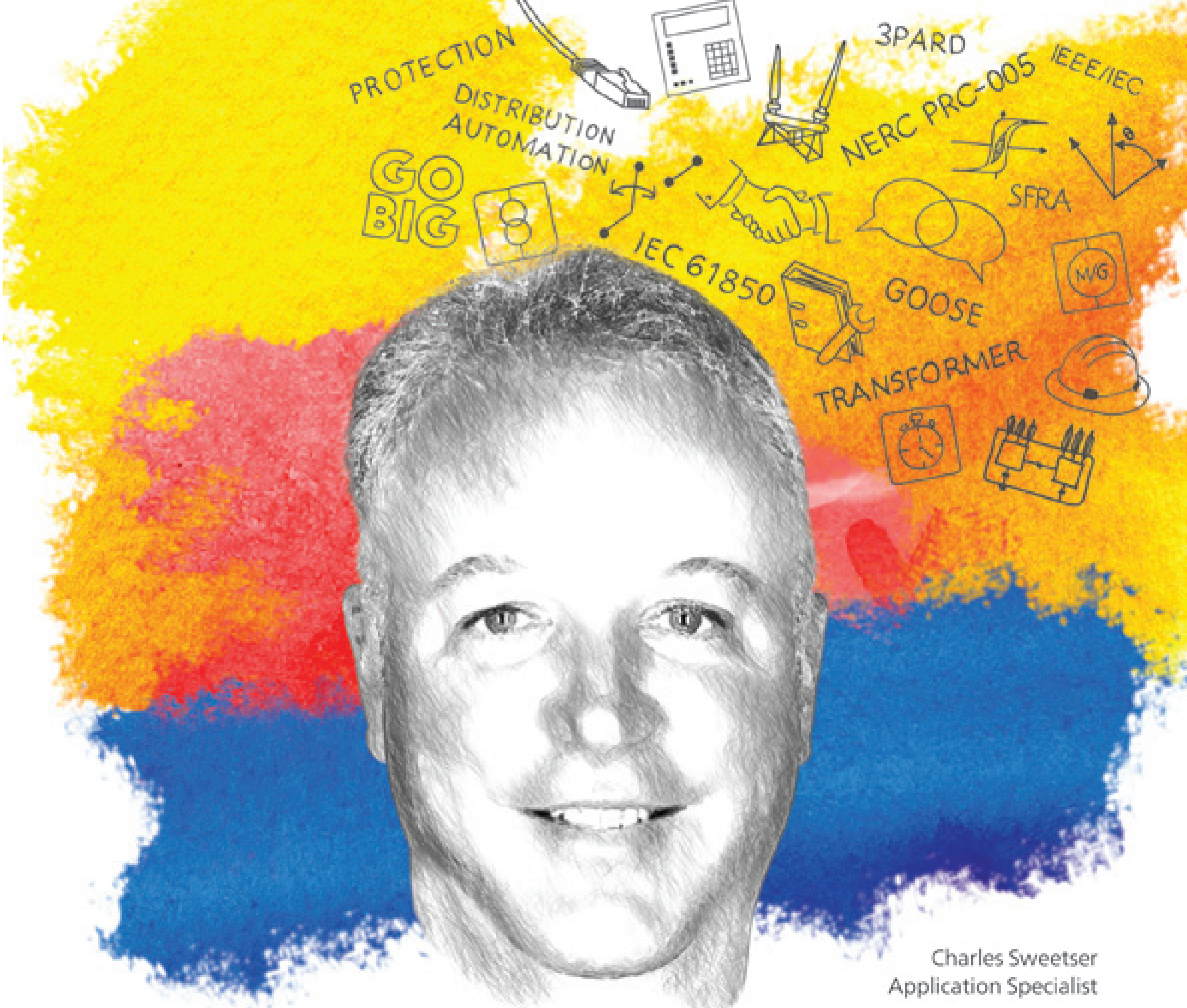
Project Route

The route will cover approximately three miles along an electric main line circuit. PSEG Long Island crews will be working on the following streets in the Town of Southold:

- Main Road (Route 25) north of Pipes Neck Road to north of Chapel Lane
- Main Road (Route 25) between Silvermere Road and Old Main Road
- North Road (Route 48) between Chapel Lane and Main Road
- Main Road (Route 25) between North Road (Route 48) south of Maple Lane

This project is funded through the FEMA Hazard Mitigation Assistance Program, which was established to harden electrical distribution infrastructure against future storm damage and help restore power more quickly. In 2014, more than $729 million of federal recovery funds were secured for the Long Island Power Authority via an agreement between Governor Andrew M. Cuomo and the Federal Emergency Management Agency (FEMA), under the FEMA 406 Mitigation Program.

For more project details, including work locations, visit *www.psegliny.com/reliability*.



Charles Sweetser
Application Specialist

Project boosting electricity network from Kintyre to Hunterston completes on time and on budget

March, 2016

A multi-million pound project by Scottish Hydro Electric Transmission (SHE Transmission) and SP Energy Networks to reinforce the electricity network on the Kintyre peninsula in Argyll to Hunterston in North Ayrshire has been completed in just under three years.

The challenging construction required an investment of £197 million along with a multi-disciplined and technically skilled workforce to successfully deliver its three main elements:

- New grid substations built in the forest at Crossaig on Kintyre and Hunterston Power Station on the North Ayrshire coast
- The replacement of 14km of 132kV overhead line connecting the Crossaig and Carradale substations, and finally
- The construction of an underground cable connection between Crossaig substation and Port a'Mhidair, where the cable becomes buried beneath the sea bed and runs across the Kilbrannan Sound around the north of Arran before connecting again onshore at Ardneil Bay in North Ayrshire; a distance of some 41km

The majority of the project has been located in SHE Transmission's licensed area which covers the north of Scotland, with the final part of the works, where 3.5km of land cable was needed to connect the line at Ardneil Bay to Hunterston, being carried out by SP Energy Networks. To reduce construction impacts, SP Energy Networks installed this section using the same route as the Western Link, a further subsea cable project currently being installed that will increase the flow of power between Scotland, England and Wales.

Director of SHE Transmission, Dave Gardner said: "The different aspects of this project involving power lines that travel overhead, underground and beneath the sea bed have raised some interesting challenges, and we've been very fortunate to have had the guidance of fisheries, marine and military organisations from the inception of these works.

"The completion and energisation of this part of the network gives renewable developers the capacity to build further generation in this area and, importantly, builds a stronger power supply for those who live and work here. We only need to look back to March 2012 when storms and snow brought this area and the Isle of Arran to a standstill, leaving thousands of our customers without power and further reinforcing our determination to upgrade this network to make it stronger for the many householders and businesses that rely on it.

"I'd particularly like to thank the residents and their community groups, not only for their patience and understanding during these works, but for the way they embraced the project; seeking information from the earliest consultations, providing feedback and ultimately involving us in their community events - such as the Carradale Center and the Harbour Day - which we were so proud to be part of."

Pearse Murray, Transmission Director, SP Energy Networks said: "This was a highly complex project delivered ahead of time, and another good example of transmission companies working in partnership to deliver strategically important upgrades to the network in Scotland.

"As well as increasing security of electricity supply supplies, the new link will also provide new capacity and ensure that renewable energy generated in Kintyre can be transmitted to areas of demand in south and central Scotland and beyond."

Stuart Irvine, the Chair of East Kintyre Community Council added: "It was so reassuring to see that, during these most recent storms, we had only the tiniest flicker to our lights and nothing more; no outage and that's a huge improvement.

"While the project was ongoing, we were aware of increased traffic on the single track road between Campbeltown and Crossaig, which was leading to damage and potholes but when SHE Transmission recognised the problem they set about repairing and maintaining it; even introducing more passing places and increasing the size of existing ones. These improvements - along with other small, local projects they helped with - will benefit the community for many years to come and we are most grateful to SHE Transmission."

The Kintyre-Hunterston project has been completed on time and on budget and, in addition to providing a more secure electricity supply to the area by strengthening the transmission network it will allow additional capacity for generators of renewable energy to connect to the grid. With immediate the new links allow the boundary capacity to rise to 420MW to enable the connection of current and future wind, hydro and solar generation developments

PSEG Acquires 37.8 MW Solar Project from juwi

March, 2016

PSEG Solar Source announced it has acquired a 37.8 MW-dc solar energy facility from juwi Inc. (juwi). The facility, to be called the PSEG San Isabel Solar Energy Center, is located in Las Animas County, Colorado about 165 miles south of Denver. This latest addition represents an investment of over $60 million and will increase the capacity of PSEG Solar Source's portfolio to 315 MW-dc.

The PSEG San Isabel Solar Energy Center has a 25-year power purchase agreement with Tri-State Generation and Transmission Association, Inc., a wholesale electricity generation and transmission provider. It sits on approximately 300 acres and has a 25-year lease with a private landowner.

"Over the last few months, we have substantially increased our portfolio of cost-effective, community based solar solutions and brought the benefits of renewable energy to communities across the country," said Diana Drysdale, president of PSEG Solar Source. "With the PSEG San Isabel Solar Energy Center, we are expanding our presence in Colorado and will deliver enough clean, reliable energy to power over 9,600 local homes."

juwi developed the project and will act as its the engineering, procurement and construction contractor and operator. The facility will use approximately 121,000 poly-crystalline panels with tier one inverters. Construction is underway and commercial operations are expected to begin by the end of the year.

"We are proud to have developed another utility-scale solar project in our home state of Colorado that will provide affordable and clean energy for Tri-State and its members," said Michael Martin, president of juwi. "The PSEG San Isabel Solar Energy Center is the latest example of a tremendously successful partnership between juwi and Solar Source, helping to bring a more sustainable future for all."

This is PSEG Solar Source's 17th utility-scale project in 12 states and the second in Colorado. Its other projects are located in Arizona, California, Delaware, Florida, Maryland, New Jersey, North Carolina, Ohio, Texas, Utah and Vermont.

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

An In-depth View of Smart Grid

We are in discussion with Advanced Control Systems™ (ACS) CEO Kevin Sullivan and ACS CTO Gary Ockwell on the subject of Smart Grid as it applies to how utilities need to take advantage of the latest technologies to upgrade their entire grid.

EET&D: What is the biggest impediment utilities face with respect to Smart Grid implementation?

Mr. Ockwell: Budget and time. Most people think of the Smart Grid in terms of self-healing automation to improve reliability, or Volt VAr control to reduce cost. The problem is these technologies take time and money to implement. For most utilities the foreseeable automation horizon for the potential of the Smart Grid may not apply to more than 20 percent of their network over five years. Utilities need to be able to take advantage of the Smart Grid in a way that applies to their entire network from the beginning, not just the part that they can automate in the near future. Unless the complete grid – not just a small portion – benefits from the technology, the business justification of today's investment may be inadequate. Worse, the number of customers that benefit from the Smart Grid is commensurably limited.

EET&D: Apart from the time and budget investment to expand automation to all of the grid, what benefits can a utility derive from the Smart Grid for the non-automated portion?

Mr. Ockwell: Popular technologies such as 'self-healing' can be applied to all of the grid from the start. A major cost is in the automated switches, capacitors, communications and their installation. But what if we leveraged the existing automation and communications to apply these same technologies everywhere?

For example, Smart Grid self-healing solutions depend on deriving a solution based on identifying the fault location. Prior to the Smart Grid, the Outage Management System (OMS) determined the fault location using an exhaustive search of the feeder for the faulted section. Unfortunately, the nationwide average for fault discovery consumes 60 percent of a utility troubleshooter's time. The Smart Grid self-healing technology improves on this process to instantly and automatically identify the fault location. The self-healing methodology of fault location is determined through down line detection of the existence of fault current at the switching points. The location, coupled with knowledge of the operation of protective devices and a lock out signal, indicates that the existing protection schemes to restore were not successful, and the fault persists. While this is a great solution, it is too expensive to purchase and install the necessary equipment.

The entire management of the restoration process can be improved by blending the legacy OMS process of identifying fault location with Smart Grid network analysis. The Smart Grid can improve the troubleshooter's discovery process by narrowing the search area to those feeder sections that could support the fault current measured by the existing substation relays. This technology is called short circuit analysis or fault location.

EET&D: Is there any further improvement to be gained in the crew's processes?

Mr. Ockwell: Yes, the crew's ability to view the network using their smart phone or tablet, while the DMS highlights the potential areas of the fault location, greatly improves their troubleshooting speed. Furthermore, we overlay the control center's network topology on a Google map, showing the potential fault locations on a map to expedite the discovery process. Even without an investment in automation, we can more effectively leverage the tools crews have to accelerate the management of the outage restoration. Our communication medium is already in their pocket and is used to inform and deploy the crews. This is the beginning of the 'Human Grid.'

EET&D: Where does the 'Human Grid' go from there?

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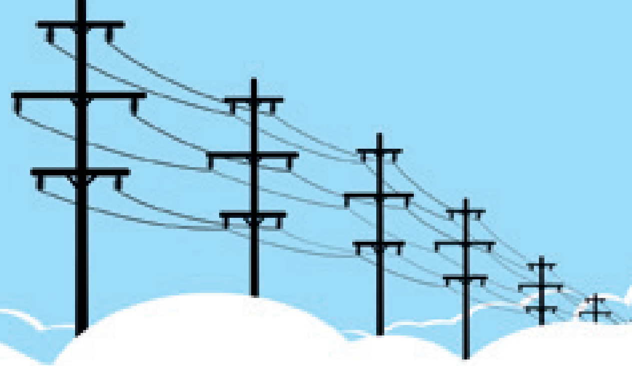


Mr. Ockwell: Let's discuss the next step in the process we described. Once the fault location has been verified more rapidly than is possible using the existing 'search and find' methodology, the next step in Smart Grid's automated self-healing process is the isolation and upstream restoration of the unfaulted sections. The classical approach to the Smart Grid requires expensive remote control switching to perform this function.

However, lacking the automation equipment, we again deploy the crew in a more efficient manner without added automation or communications. We push the derived switch steps to the crew's mobile device, where they can view the near real-time map topology, which is overlaid on Google map. The DMS-created switch plan, or OMS work order, is integrated into the topology map and pushed to the crew's mobile device. Also visible is the placement of clearance, hold or information tags. As the crew completes the switch steps to isolate the faulted section, the event is immediately time-tagged and the status change is pushed to the DMS. The resultant topology change is evident when the topology is updated on the crew's mobile device.

Supported by secure confirmation/verification that the crew is finished with the isolation (verified by the operator topology change on his map), the operator in the control center can issue a reclose supervisory control to the substation breaker for the upstream restore. The automatic time-tagging of the manual operation using the mobile device provides an accurate recording of the restoration—a vital component of the SAIDI, CAIDI calculations. Once again, engaging the crew is enabling the Human Grid.

EET&D: Can any other part of the self-healing process benefit the grid without automation?

Mr. Ockwell: Yes. The downstream restoration follows a similar process – a vast improvement over the classical restoration methodology. Before the Smart Grid, complex switching plans were typically generated in the control center using a load flow tool to verify the results. The switch plan was either verbally communicated or, in the event of planned outages, handwritten on a switching form and faxed or emailed to a service center for execution.

The Smart Grid self-healing analysis accomplishes this switching analysis and generation instantly using a real-time load flow. The resultant switch plan is approved by the operator and authorized for direct execution and control.

However, if automation is not available everywhere, once again engaging the human Grid opens the benefits of the Smart Grid network analysis to the entire grid and to all of the public. Using their smart phone or tablets, crews become the Smart Grid's automation and communications at a very low cost. The quality of the Smart Grid-derived solution is the same with or without automation. Automation simply improves the speed of implementation. Integration of mobile functions with Smart Grid applications is how we enable the Human Grid to accomplish the work of the Smart Grid.

EET&D: What is the next step in the Human Grid beyond a tighter integration of the crew and the DMS?

Mr. Ockwell: Engagement of the public with the Smart Grid control center. The public, armed with their mobile devices, are a powerful source of telemetry and control information for the utility. After all, the public not only controls the load, they are the load. Demand response, load shed, problem reporting, outage restoration confirmation, and more can easily be achieved by engaging a cooperative public. For example, the ability to passively set the home temperature, which typically represents half of the residential load, can have a large impact on the feeder load. Using incentive programs and text messages, the public can become ready and willing arms of automation for the utility with very little investment. The information that a cooperative public can feed back to the utility is immeasurable. Effective Customer Engagement ignites the Human Grid.

EET&D: A cooperative public? What does that imply?

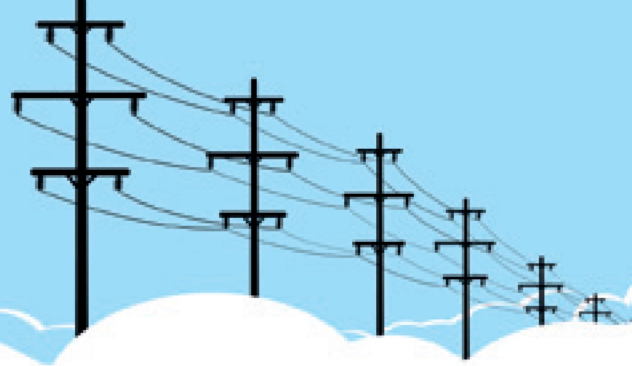
Mr. Ockwell: J.D. Power's 2016 Electric Utility Business Customer Satisfaction Study reported an important public perception. They said that "Power quality and reliability satisfaction among business customers who experience a power outage and receive information regarding the outage is 23% higher than among those who do not receive any outage information."

Consider that without any actual automation investment, a utility can achieve a 23 percent improvement in power quality and reliability satisfaction, as perceived by the public. The cost of opening lines of communication with the public is far less than the cost of automation. When it comes to customers, for all practical purposes, their perception is the utility's reality.

Smart Grid automation is important. However, just as important is how the improvements are communicated to the customer. The same report also found that "proactive communication, including using digital and social media, is key to improved business customer satisfaction with electric utility companies". They concluded that proactive and personal communications methods of all types are the most effective tools, with an approximate 33 percent improvement in customer satisfaction. Utilities need to open up communication channels to the public in a proactive, personal way. If the public can be moved from 'satisfied' to 'engaged' or 'cooperative,' the utility can accomplish much success.

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid



EET&D: What is the difference between a satisfied public and a cooperative public?

Mr. Ockwell: The difference is important. You may recall that the DOE's seven characteristics of the Smart Grid calls for customer satisfaction. A satisfied public is not enough. A cooperative public derives a perceived benefit from the technology. That is the problem with AMI – it offers the public no perceived value proposition; the value is the utility's alone. In fact, AMI is often viewed with suspicion by the public. However, if the utility can push daily or weekly information to the public, the utility can turn a satisfied public into a cooperative public. With the latter, you can achieve the low cost benefits for all concerned by leveraging the Human Grid.

EET&D: Why is this approach not more commonly used?

Mr. Ockwell: Perhaps the reason is that the Smart Grid was designed by engineers with a love for automation. A more social approach to the Smart Grid is needed. Utilities have been slow to adopt communication channels preferred by the public. Even today, many utilities are installing new automatic voice response systems, without considering that the younger generations do not prefer voice communications, even with their friends or family, let alone the utility. From the Smart Grid point of view, the technology is again focused on automation rather than on an analysis tool set useful in the hands of the operator for the non-automated portions of the network – which is the majority of it.

The goal is to engage the crews and the public as the "boots on the ground" to collect telemetry information, and for the crews to affect changes in the network using an efficient integration with the DMS and OMS applications. The supreme advantage of the Human Grid is that it exists and can be engaged at a low cost with optimum results.

We will now be speaking with ACS CEO Kevin Sullivan

EET&D: What is foundational in transforming the grid?

Mr. Sullivan: Energy is foundational to our civilization and the people that work in the energy management industry must wake up every day and come to work with a single purpose in mind of how to place real-time information and control in the hands of the utility.

EET&D: How should the 21st Century Grid provide the necessary tools for the energy management industry?

Mr. Sullivan: Utilities' need for speed requires a real-time integrated platform. Everything can be accomplished in real-time when utilities have one integrated data source. Many systems build their data, based on derived and pseudo data points and serial links. Utilities could benefit from an integrated platform for a single real-time database, enabling them to address real-time incidents. Customers take the data from the field in real-time and through integrated applications and advanced controls using real-time data, they have control at their fingertips to make prompt decisions to optimize grid efficiency.

EET&D: Did you understand that day one or did it develop over time?

Mr. Sullivan: We started with the digital control systems. In addition, the edges of the grid are changing with the deployment of disruptive technologies, such as Distributed Energy Resources (DER), that also require integration and control in real-time. The technology addresses current and future grid operational challenges. In order for utilities to better manage energy today, companies like ours have and will continue to enhance solutions and lead the industry with innovative technology to rapidly adapt to a continuously evolving environment with ever increasing disruptive events -- from extreme weather to forced outages.

EET&D: Does the industry see the Grid Transformation?

Mr. Sullivan: I think the industry is starting to see it, where there is a high degree of penetration of renewable and/or sub generation at the consumer end. It's starting to see the needs in order to keep the grid stable and keep lights on. The need for speed and the ability to manage in real-time has become far more apparent. I would say that some of the extreme events like super storm Sandy and other uncontrolled events have also amplified the need to be able to manage the grid in real-time.

EET&D: It seems sensible that you would want real-time, so why would there be any hesitation? Why has it taken so long for the industry to recognize the need?

Mr. Sullivan: It is a factor of the installed base. The utility industry has been around since the early 1900s, and for decades was a central generation source with transmission lines leading to the load. For many, many years, assets have been built up, as the control of that grid has been ingrained in the utility industry. Only now, with the IT revolution and the digital revolution, have people started to understand the need to make the change. When you have a tremendous amount of assets and copper in the ground and investments that you've made, it is hard to make the change to the more advanced control systems. Therefore, many utilities have to make a business case for it and a lot of the business case arguments are related to event-driven aspects like an outage.

EET&D: Do utilities seek a range of solutions?

Mr. Sullivan: Solutions reside centrally in the utility control center and manage the entire grid from a central point. Feeder-based or line-based distribution systems balance each feeder. This solution is a distributive control system. An example of that technology is when your lights try to recover power. Your energy goes out and comes back on and your lights flicker. The advance control systems on the feeder allow three different attempts to reroute the power and reinstate the lights and the energy to the consumers. After the third attempt, if unsuccessful, the utility communicates to send a crew.

The solution could also include RTU products. This is a very advanced upgrade solution for very old RTUs. The technology is available to seamlessly and effectively upgrade a utility to the digital age without a big outage.

Last but not least, another aspect worth noting is that the OMS can be taken to the next level with mobile solutions. It engages the consumer in the energy equation, placing control and communication in their hands via the smart phone to either participate in an outage or to actually provide energy management solutions as consumption management of their own energy.

EET&D: How does that work?

Mr. Sullivan: The technology uses advanced applications on a smart device, reconnects back to the central control room, and provides direct feedback to the utility. This is a solution that the utility pushes to the consumer. It engages the consumer by providing points of credits for participation, and/or involving the consumer in what we call demand response. That means if the utility has a problem supplying energy during peak hours, it can request through the technology that a consumer actually help control the load and participate directly with the utility. That technology is based on central communication IT technology today but it is very integrated with what I call real-time operating systems sitting in the central control.

EET&D: Does it take much for the consumer to understand?

Mr. Sullivan: I think consumers that enjoy a very low electricity bill will not be as interested as customers in the Northeast and in California, where people have seen their monthly income affected by the consumption of electricity. Consumption of electricity is an interesting business. It is never sold and just used. Sixty days after consumption, you find out how much electricity was used. What we have done with this application is to put real-time controls in the hands of the consumer to see how much they are spending today, how much would they save tomorrow, and what they would spend in a year if they implement the savings of technologies that we provide.

EET&D: It has been a real pleasure speaking with both of you. We appreciate your taking time from what I'm sure are crazy schedules. Smart Grid is going to be key in most peoples' lives going forward and it's good that companies like yours are on the cutting edge.

GREEN OVATIONS

Innovations in Green Technologies

Dealing with severe storms: utilities are applying technology and lessons learned

By Bradley Williams

In January, Winter Storm Jonas slammed the eastern United States with snow, sleet and freezing rain – dumping as much as 42 inches of snow in West Virginia (and more than a foot in 14 other states) and causing significant coastal flooding in Delaware and New Jersey. The heavy snowfall, high winds and ice took out power to more than one million customers in states from Arkansas to Massachusetts.[1] The National Oceanic and Atmospheric Administration called it the fourth most powerful snowstorm – of the 199 snowstorms since 1900 it has analyzed – to hit the Northeast in that timeframe. [2]

Clearly, in the face of a storm of this size, it isn't possible to completely prevent outages. But, armed with the lessons learned from Superstorm Sandy in 2012 and other massive storms during the past few years, many utilities have made sizeable investments in hardening their infrastructure, updating their technology, and in more complete planning and preparation in advance of the storms.

Planning and preparation strategies

Those two Ps – planning and preparation – can continuously iterate, fueled both by the incorporation of lessons learned from previous storms and by the utilization of technology and in-application data analytics. Providing an effective response – and a proactive one, in cases like Winter Storm Jonas, where the storm's path and effects were predicted with a fairly high degree of accuracy – is at the heart of any utility's storm strategy, continually fed by actionable information.

Mutual aid has always played an important role in storm outage restoration. Here, too, technology and operational processes are playing an increasing role. For example, for Winter Storm Jonas, Commonwealth Edison Company (ComEd), a unit of Exelon Corporation, proactively sent more than 200 crews and a new mobile command unit vehicle to provide restoration assistance to electric utilities PECO in Philadelphia, PA, and BGE in Baltimore, MD, with crews leaving Illinois both the Thursday and Friday before the storm was due to hit the East. In a news release, Terence R. Donnelly, ComEd's executive vice president and chief operating officer, noted: "With millions of people facing power outages on the East Coast, we think it's important to work with our sister utilities to get customers whose power service is impacted by this storm restored as quickly and safely as possible. This is one of the strengths of the Exelon group of utilities. We have similar processes that make it more efficient to provide assistance to each other during significant storm events such as Winter Storm Jonas." [3]

Technology enabling real-time visibility and communication with field crews

Post-outage analysis, an important part of any future planning scenario, already provides utilities the opportunity to review procedures and practices and incorporate any new lessons learned into new best practices for outage restoration and recovery. As more critical technology applications are added to advanced distribution management systems and network management systems, utilities are taking advantage of this advanced technology to drive increased operational performance.

This integration of other operational technology – such as the geographic information system, SCADA, mobile dispatch, mobile workforce management and advance metering infrastructure systems – is providing a clear, near real-time, end-to-end view of the utility's entire distribution network.

Add analytics and data visualization tools to the mix, pulling together large volumes of data from multiple sources into one 'single version of the truth' (aka operational system-of-systems), and the 21st century utility now has a powerful, integrated, real-time engine ready for use in coordinating its outage response and more effectively managing crew resources.

What does that look like in a storm operations control center? This 'single version of the truth' approach, and the ability to combine and analyze source data, model data and map data on a single web-based platform provides system operators with much more granular knowledge about the extent of any outage. As well, it provides the ability to more quickly dispatch crews with the right equipment to each outage area, and at the same time allows the utility to give its customers and other key stakeholders more clearly defined and outage-specific estimated restoration information. This means the system must be scalable and tested to handle storm volumes of events. Best practices include storm drills, system tune-ups with current software release updates, as well as system performance testing well prior to storm season.

Keeping customers in the loop

Integrating outage management and distribution management systems with other operational technologies is a boon to storm management, giving utilities a real-time, end-to-end view of the distribution network, making outages easier to identify and repair crews quicker to dispatch to the affected areas. But that's all real-time data and information being used directly for restoration operations.

Unless that information is also used to regularly update customers, it's only half the battle. Increased operational efficiency, effectiveness and reliability are all part of your relationship with your customers, but good communication is equally important. Regulators demand it: in recent years, more rigorous mandates for responsiveness have been imposed on utilities, particularly for more accurate restoration estimation and increased frequency of communications to customers. And customers demand it: when the power goes off, they reach for their mobile phones and cellular-connected handheld devices, looking for answers. Within the new utility, operational tools and communications tools must work hand-in-hand.

Customers demand timely and accurate updates of events affecting them provided in their preferred mediums, AVR phone calls, texts, e-mails, smart phone notifications, etc. In the past few years, social media in particular has become a new platform for utility communications. Duke Energy experienced just over 500,000 outages in the Carolinas at the peak of the weekend storm, but had reduced that number to about 50,000 by Sunday, January 24.[4] While more than 7,000 crew members were out in the field restoring power, the utility was also busy using social media channels including YouTube,[5] Facebook and Twitter in addition to its website updates and outage map to stay in regular touch with its customers in order to update them on restoration progress.

While Winter Storm Jonas was not as devastating in terms of impact and damage as was Hurricane Sandy in 2012, utilities affected did not 'dodge the bullet' by luck alone. Strategic hardening and modernization efforts initiated following 2012, ultimately, meant these utilities were able to launch a proactive assault, getting necessary crews in place and ready to go, monitor their networks on a real-time basis, and mount timely and efficient restoration efforts.

About the Author

Bradley Williams is vice president of industry strategy, Oracle Utilities. Williams is responsible for Oracle's smart grid strategy as well as utility solutions for outage management, advanced distribution management, mobile workforce management, work and asset management, and OT analytics. Williams has spent the last 30 years driving innovation in the utility industry in roles, including T&D power system engineering, technology development, asset management, and industry analyst.

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From Research to Action

EPRI demonstrates $5 demand response

By Walt Johnson, Brian Seal, and John Simmins

In December 2015 the Electric Power Research Institute (EPRI) researchers brought an integrated and interoperable grid one step closer to reality by demonstrating the versatility of a leading connectivity standard in a common device that costs about $5.

EPRI loaded and ran its Linux-based, OpenADR 2.0b automated demand response software on a Raspberry Pi Zero, a cheap yet powerful computer meant to represent the kind of inexpensive devices, such as thermostats, that can be created today. In doing this, EPRI proved that OpenADR could be used cost effectively in residential and small commercial applications, in addition to its common use in industrial and large commercial applications.

OpenADR 2.0b, which has seen adoption worldwide since its release in 2013, is a communication protocol for demand response (the ability of a load to respond to signals from the grid). Once loaded with the software, a device using the OpenADR standard to communicate is activated by an OpenADR server (called a "virtual top node," or VTN) which sends a standard message to any client (called a "virtual end node," or VEN) connected to it. One beauty of the standard is that the same device can act as both a VTN and a VEN, allowing a VEN that has received a message to act as a VTN and pass messages to additional devices. Thus, the architecture is hierarchical and infinitely scalable.

The EPRI open-source implementations of the OpenADR 2.0b VTN and VEN were released in February 2014 and are proving to be very popular. OpenADR was originally developed for the California Energy Commission by the U.S. Department of Energy's Lawrence Berkeley National Laboratory and is used for managing large electrical loads by investor-owned utilities in California. When the National Institute of Standards and Technology (NIST) and the Smart Grid Interoperability Panel (SGIP) worked to identify and address interoperability gaps, they identified OpenADR as a key standard for demand response. As a result, OpenADR is listed in the Smart Grid Catalog of Standards.

In the past, OpenADR may have been viewed as only being suitable for large systems and facilities, and only being able to operate on PC-like platforms. But with the current state of technology, OpenADR can operate on small, inexpensive platforms. The Raspberry Pi Zero is just one example of such a platform and is a lightweight version of the popular Raspberry Pi platform. Running Linux, EPRI was able to load the same OpenADR 2.0b client that had been used previously, demonstrating the portability of the standard.

While technically straightforward, this demonstration is significant because it shows that the range of target end devices and the number of potential applications that OpenADR can feasibly address has expanded tremendously.

This fact is further supported by recent field demonstrations in which EPRI is running the OpenADR client on Wi-Fi modules for residential load control applications. Besides the demonstrations being done by the project, EPRI's certified, open-source OpenADR 2.0b VTN and VEN implementations have each been downloaded thousands of times and are being used in a wide range of EPRI and commercial projects.

For more information about EPRI's Information, Communication and Cyber Security work visit *www.epri.com*.

About the authors

Dr. Walt Johnson is a Technical Executive at the Electric Power Research Institute (EPRI) where he specializes in smart grid strategies, technologies, standards, applications, and IT Enterprise Architecture for EPRI's Information and Communication Technology research. He manages EPRI's Automated Demand Response and Ancillary Services Demonstration Projects and supports EPRI's Transmission and Distribution Modernization Demonstration Projects on Data Analytics. He also heads EPRI's ICT Innovators Forum for solution providers. As an IT systems specialist with more than thirty years of national and international experience, Dr. Johnson has held leadership positions at NASA, Gartner, Raychem, and the California ISO, and headed a CIGRÉ task force on architectural standards for real-time grid control systems. Prior to joining EPRI, he worked for DNV KEMA as a business process subject matter expert supporting execution of smart grid and energy IT consulting projects involving ISOs, RTOs, and global industry consortia. He holds a B.A. (cum laude) in Chemistry from Claremont McKenna College and a Ph.D. in Inorganic Chemistry from Indiana University. He is a member of IEEE and of Sigma Xi, the Scientific Research Society.


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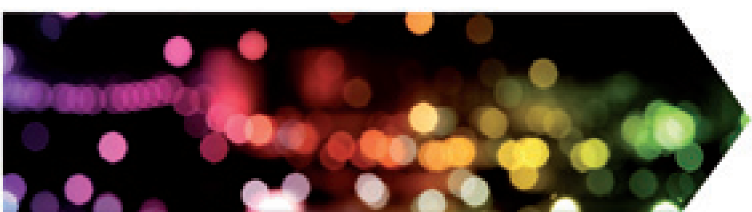
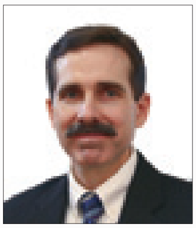




Brian K. Seal is a Technical Executive at the Electric Power Research Institute (EPRI) where he manages EPRI's Information and Communication Technology research in the areas of advanced metering, demand response, and integration of distributed energy resources. In this role, Brian has been actively involved in international efforts to create standards for interoperability of consumer appliances, solar inverters, and smart meters. Prior to joining EPRI in 2008, Brian worked for 20 years at Cellnet (now Landis+Gyr) and Schlumberger (now Itron) where he managed product design and development of utility metering and communication equipment. Brian received Bachelors and Master's degrees in Electrical Engineering from the Georgia Institute of Technology, is an active member of IEEE, IEC, and other standards groups, and has been awarded several patents related to utility communication systems.

Dr. John J. Simmins is a Technical Executive at the Electric Power Research institute (EPRI) where he manages the Information and Communication Technology for Distribution project set. His current research focuses integrating back-office applications and integrating with devices and personnel in the field. Dr. Simmins also leads the EPRI efforts in the use of augmented reality, social media, data analytics, and visualization to improve grid resilience. Prior to joining EPRI Dr. Simmins was with Southern Maryland Electric Cooperative where he managed the engineering and operations applications. He received his B.S. and a Ph.D. in Ceramic Science from Alfred University.

Bridging IT and AV Infrastructures in Electric Power Control Rooms

By Samuel Recine

Data, communications, and AV are now all transmitted on Internet Protocol (IP) infrastructures. While there are still mission-critical applications that require dedicated hardwired or over-the-air transmission and switching over dedicated connectivity, there are few frontiers that have not been conquered by the relentless advance of IP. Data (text) had the smallest bandwidth footprint and was the first application to be captured, extended, and switched cheaply over global distances. Voice (audio) came next. And video has been the most demanding application to stream across IP networks because of the sheer amount of data involved on the finite bandwidth of IP infrastructures. But evolving infrastructures combined with evolving techniques for moving video have overcome almost all challenges except for perhaps a few holdouts.

When the AV industry began the long and painful overhaul of its Standard Definition (SD resolution) extension and switching backbones cost-effective encoding of HD only appeared in the last third of this ten-year transition. Now that the market is poised to migrate from HD to 4K the transition time will be cut almost in half. And the ability to comfortably move 4K around over IP is available at the beginning of the transition. Netflix today streams 4K content at 15mb/s. So resolution is no longer an issue since encoding effectiveness has now outpaced both content and end point adoption.

It is now possible to transmit video with zero compression to the color space – even in low bit rates. This is particularly useful to high frequency applications like compressed and streamed PC graphics. In electric power SCADA and HMI systems this means that information with fine details – including lines only one pixel thick – can be recorded or streamed with visual integrity.

Distance and cost-effective extension and switching have been breached by audio-video over IP as has stream density for mass distribution.

It's no surprise that having all text, audio, and video/graphics information now living on the same medium that the applications for this convergence are providing value in just about all enterprise, government, industrial, entertainment, and residential applications.

The emergence of AV over IP has opened up many useful applications for the electric power industry including the ability to safely share operator data between multi-monitor operator workstations and even a collaborative video wall (as pictured), or record entire operator shifts to network storage (NAS) for training, review, liability, and more.

In the electric power industry several trends are already deeply engaged.

Video enhances decision-making. Seeing an alarm on an electric grid SCADA monitoring system provides information to an operator that 'something wrong.' The two possibilities are usually:

1. A faulty sensor
2. An actual problem that needs intervention

What if an IP camera is at the node that is producing an alarm condition? If an operator can view a camera at that location it is possible to add 'what is the problem' to the alarm prioritization decision making process.

Seeing that camera doesn't come with the same threats and hurdles as many still perceive. There are products on the market today that allow data from a 'camera' (or AV) network to live on different cables and switches than IP networks of the critical operator workstations and servers connected to the field of PLCs. While 'both' AV and IT information can be available on the same operator displays, it is still possible to have separate IP networks feeding both types of visual information to human operators. The separate networks can be managed together or discreetly – including different user permission levels if required.

The same technology that can be used to 'decode and display' AV information on operator workstations can also be used to 'capture, encode, and stream' the graphics information from an operator. This too opens up many useful applications.

Quality compression of user graphics data makes it possible to cost-effectively store operator shifts to network storage (NAS). Even multi-monitor workstations can be recorded in their entirety if required.

Since it is possible to encode, decode, and display from the same equipment and over standard IP, it is possible to create generic training systems that work agnostically across multiple different software platforms. It is no longer necessary to have different recipes for recorded SCADA operations versus Microsoft Office or browser-based applications. Productivity apps, GIS, SCADA, CAD, etc. can all be streamed or recorded together. By being able to decode and display AV information from NAS without touching a real data network at all, operators can retrieve stored training files safely even in live environments.

Matrox Mura IPX 4K capture and IP encoder/decoder cards feature an on-board network interface controller (NIC) allowing utilities and public safety operators to work off a separate, AV-dedicated network and securely add drone views, IP cameras, recordings from network storage, live desktop captures, etc., onto a video wall or workstation—with zero impact on the host system.

Operators' capabilities in a control room or across control rooms at different locations can be further enhanced by sharing data between operators. Again: using entirely different switches and cables than real data networks, it is possible for operators to see each other's work based on real-time encoding and streaming. This improvement in context and decision-making acuity has tangible benefits to maximizing operator effectiveness.

The same technology makes PC graphics information available 'across' functions in an organization. Supervisors can switch from one operator station to the next to keep an eye on many different interfaces including several at once if required. Evolving standards are also gradually making it easier to share protected content over IP networks. HDCP 2.1 contains improving flexibility towards "interface independent" sharing of protected content – including over standard Ethernet. These evolutions can help improve how government and industry is served by allowing serious data networks to be combined with things such as broadcast television on the same operator displays. This can make news and weather more comfortably accessible to control room operators and start removing the need for separate television infrastructures to support operators in their functions.

And last but not least we must consider some never-before-used or at minimum previously ultra niche capabilities opened up by convergence over IP technologies. Drones is a hot topic for example. Services are now coming into the market to offer utilities and public safety operators low altitude camera views. This could transform myriad functions including diagnosing hard-to-reach locations for outage repairs all the way to monitoring trees and vegetation near overhead powerlines.

The sudden availability of these new form-factors of camera-over-IP data are producing instant hybrid use cases for camera video information from drones combined with graphics information (say GIS maps corresponding to the "locations" of the drones) from PCs. Some operators wish to merge the video footage with the graphics data with real-time encoding so that the information can be streamed as a single (hybrid) 'video' stream which can be accessed by multiple people at once on any device from laptops to handheld devices, etc.

Video processing capabilities also offer capabilities to enhance these converged video/graphics capabilities. By providing varying levels of transparency on airborne footage from cameras and super-imposing that on GIS maps, it might soon be possible to have GPS-like capabilities that lead directly to an outage point literally visible on your GPS display.

While some of these ideas may still sound exotic right now for the average transmission and distribution operator, one thing that cannot be denied is that technologies from the consumer electronics and PC markets have produced overwhelming new cost efficiencies for greatly improved access to decision-enhancing visual information through advances in technologies offering capture, encoding, streaming, recording, video processing, multicasting, decoding, display, and switching over standard IP.

About the author

Samuel Recine has worked in the high-tech industry for the last twenty years in the areas of sales, product management, and business development. He is currently the Sales Director for Americas and Asia Pacific at Matrox Graphics Inc. Samuel has occupied the position of product manager for high-performance KVM extension products and multi-monitor graphics enablement for remote protocols used on thin-clients and PCs. Samuel has worked closely with solution providers in electric power, transportation, dispatch, security, financial services, and process control, as well as with the Pro A/V channel. Currently Samuel is helping to train OEMs, systems integrators, and VARs in the market and helping to evangelize AV-over-IP for 4K infrastructure by working closely with providers of video walls, multiviewers, KVM extenders, encoders, decoders, transcoders, and video/graphics recording solutions.

Implement an Operational Technology Message Bus (OTMB) to Take Back Your Smart Grid

By Adam Reiss

Utilities are facing an ever-expanding universe of devices, systems, and data sources that must be managed, controlled, and integrated into a variety of critical operational systems. Anyone who has been tasked with managing the software architecture of a utility's smart grid knows just how difficult it is to integrate new smart grid systems and devices safely, cost effectively, and efficiently.

Some of the challenges you may face when integrating your smart grid systems and devices are:

- An alphabet soup of systems which you have to integrate to, such as OMS, EMS, SCADA, MDMS, ADMS, and DERMS systems. New systems are coming online every day at an increasing rate on both sides of the meter.
- Each OT system you employ has many man years of embedded operational and business logic that will need to be re-coded as each new system is brought on line.
- The appetite for consumption and analytics of real-time data is growing, but each new project brings new requirements for data cleansing known as ETL (Extraction, Transformation and Loading).
- Your smart grid data storage requirements are expanding exponentially, and you don't have infrastructure in place to intelligently reduce the flow and storage of data.
- Not only are new systems expensive and slow to integrate, but the ongoing labor required to enhance, adapt, and maintain your point-to-point integrations is destroying your operating budget.
- Bridging data across your secure and CIP compliant systems and your IT systems is difficult to get right.

If you have read this far into the article, you likely already know that most of the systems comprising the smart grid are known as Operational Technology or OT systems. According to Gartner, Operational Technology is defined as 'hardware and software that detects or causes a change through the direct monitoring and/or control of physical devices, processes and events in the enterprise.' Throughout this article, we show that OT systems architects can learn a lot from IT enterprise architects, but before we get there, it is important to point out critical distinctions between OT and IT architectural design constraints. OT System architectures must:

1. First and foremost: protect life, equipment and environment
2. Maintain service reliability
3. Operationalize real-time bidirectional control
4. Support lossy and messy radio networks
5. Support legacy equipment and protocols
6. Respond to regulatory security and quality requirements
7. Deliver deterministic bi-directional real-time performance

IT systems connect the dots within business intelligence systems and databases. A failure in IT may result in lost data or a crashed application, but an OT failure carries catastrophic potential. Operational Technology carries the burden of operationalizing real-time, bi-directional control of field devices and the data they create, whereas IT simply must maintain the ability to consume and report data from within the grid and outside data sources as needed to maintain business processes. IT is maintained from the main office of utilities, while OT extends from the home office out into the field, to secondary energy markets, and back to Operations groups. IT looks at systems in terms of planned obsolescence, but OT must maintain legacy equipment and protocols as a matter of service reliability. The number of regulatory requirements in terms of grid security and mandated reporting are growing – and fall squarely in the wheelhouse of Operational Technology. OT systems must ensure that those requisites are met, with no room for error. Even though the OT and IT spaces are distinctly different, lessons from IT can be leveraged to create a rich OT environment.

We have demonstrated that OT systems are intrinsically different from IT systems, but there is an important software category that OT architects should be embracing from the IT world, and that is the concept of middleware. According to TechTarget:

Middleware often sits between the operating system and applications on different servers and simplifies the development of applications that leverage services from other applications. This allows programmers to create business applications without having to custom craft integrations for each new application.

Beginning in the 1980s, IT began implementing three-tier architecture that allowed a separation of data, logic, and presentation layers. With three tiers, changes to each can be made without affecting the overall stability or health of the IT environment. A critical aspect of successfully implementing a three-tier architecture is leveraging middleware to create fusion between each layer. Middleware acts as the glue that ties the three tiers together – delivering a homogenized environment in which systems and applications can utilize data from each other. While middleware is conceptually rooted in IT, middleware created expressly for use in OT scenarios is an emerging category. OT middleware is purpose-built to coalesce and manage data streams, data flows, and data networks.

By providing a rich real-time integration environment, OT middleware provides architecture that allows utilities to save time implementing and deploying grid connections, while reducing the number of 'gotchas' that come up in the course of these complex interconnection activities. OT architects use OT middleware to create a software pattern where new smart grid applications are created without having to custom craft integrations for each new application.

Let us use a real-world example of embedding operational logic into a middleware platform to help illustrate the value proposition of OT-centric middleware. Our customer has a SCADA system where the COV (change of value) counter will count up continuously until the SCADA system is reset. The OMS system in this architecture is looking for a counter that only shows the COV since the last data set was read from the SCADA system. The operational logic to make this conversion can be easily implemented in hours with an OT-centric middleware solution, but could take weeks or months if a SCADA or OMS vendor was required to produce a custom solution. Another benefit of the OT-centric middleware solution is that the operational logic remains when the inevitable new Outage Management System comes in to replace the current OMS.

There have been many approaches to integrating OT systems over the years. Here are some of the more pervasive approaches employed by many utilities:

Bring in the consultants

Bringing in a consulting company to launch a new OT system such as a SCADA or Outage Management System is standard practice. Man-years are dedicated to a custom coded point-to-point integration. These solutions are not only expensive in both schedule time and dollars, but also difficult to maintain and typically require ongoing consulting contracts or dedicated engineers to enhance as system requirement evolve.

SCADA System as the man-in-the-middle

SCADA systems are designed to enable Supervisory Control (and Data Acquisition). These systems are both over featured and under featured to act as an effective OT middleware solution. SCADA systems are great at consuming data and displaying data, but not very good at managing complex dataflows and transforming data and acting as a data source. Using a SCADA system as an OT middleware solution you end up with an expensive architecture that is hard to engineer into a generic reusable solution across multiple platform integrations. Using a SCADA system in this manner is like using custom coded software to deliver real-time management dashboards. You can make it work, but each new dashboard business requirement is painful, slow to implement, and expensive.

Standard Interface Connectivity

Smaller utilities have coalesced around MultiSpeak as a standard interface among their OT systems. Implementing MultiSpeak is a good solution if the only goal of the interface is to manage communications between applications. What this approach lacks is an engine to manage data flows and implement operational and business logic. There is no active filtering of data, and no native protocol support. When using MultiSpeak or similar technologies, the business and operational rules must be embedded in one of the OT systems. Embedded solutions mean custom code, higher maintenance costs, and more custom code when systems are replaced or upgraded in the future.

Using a Historian or a Database

Utilities are no strangers to traditional and historian databases. Many historians offer built-in connectors for various protocols. From a plumbing perspective, a database will surely move data from point A to point B; because of this ease of data movement, it is not uncommon to use a database as a form of OT middleware. Unfortunately, these solutions lack the ability to manage data flows, deliver deterministic real-time performance, or embed common operational and business logic. So while they do work, these approaches could be compared to using snail mail in place of email.

IT Middleware Solutions such as Oracle ESB, IBM WebSphere or TIBCO

IT Middleware or Enterprise Service Buses (ESBs) increase organizational agility by reducing time to market for new initiatives. ESB architecture serves as a way to implement communication between applications and systems; however, the data source and data consumer must share commonalities in data formatting, protocol language, and query-response pathways. Despite the fact that ESBs may be used to create basic 'plug and play' implementations, ESBs do not solve metadata incongruities, which are frequently an issue for OT systems. While ESBs are capable of meeting many organizational goals, they fall short of being truly performant based on the fact that they are an IT middleware solution, designed to work with other IT systems. The reality is that ESBs are not architected to handle the special loading instructions and customized data transformation functions with the fine grained, determinant timing required by OT systems. Rather than relying on simple database query and response patterns, OT systems rely on data that has undergone some level of transformation based on operational and business logic. ESBs lack native protocol support; given the diversity of OT systems, devices, and applications, such support is a must for systems employed by utilities.

Operational Technology Message Bus (OTMB) – OT ready real-time middleware is the solution

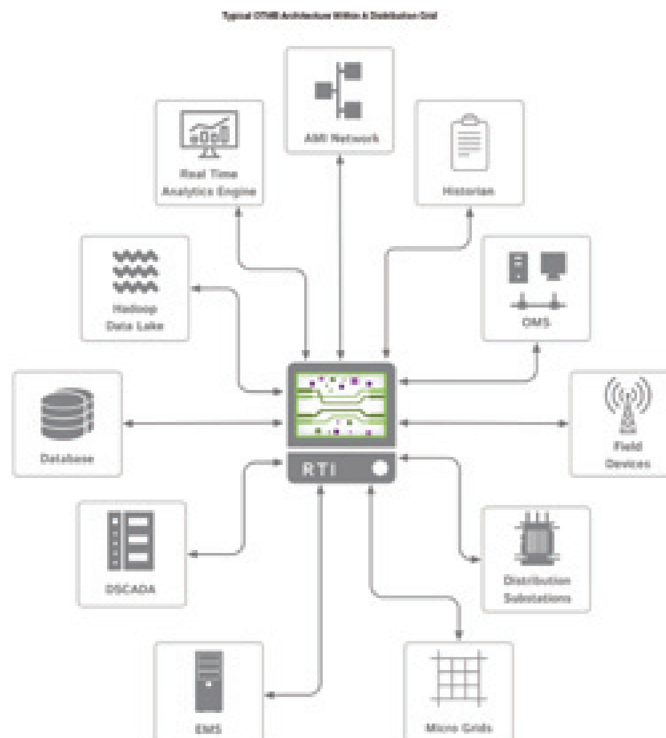
OTMB is a new category of middleware that was developed to meet the evolving needs of operations and business units alike. An OTMB is also sometimes called a Data Bus or Operational Data Bus. While a Data Bus is a good conceptual framework for an OTMB, it undersells an OTMB's inherent ability to embed operational logic and manage complex data flows. OTMB architecture ensures that OT specific organizational needs are met, while helping to bridge the gap between Operational Technology and Information Technology systems. Fundamentally, an OTMB is a real-time data flow engine that is architected to meet the needs of integrating and maintaining an exponentially growing fleet of smart grid devices and systems. OTMB software patterns reduce the time and cost of integrating new OT systems and devices, and lower the long-term operating expense of maintaining and enhancing your OT systems.

OTMBs must have the following attributes:

- **SCADA class in-memory processing** to meet sub-second latency requirements.
- **GUI-based Configurable data flows** – mapping, statistical functions, filtering, and data reduction are required functions to meet the real-time data manipulations requirements of smart grid systems.
- **Templating of data flows** – Integrating hundreds of thousands of data points cannot be done through a GUI alone. An OTMB must support abstracting data types into a manageable and maintainable classification system.
- **Populated at run time** – critical OT systems must load new file configurations live. OTMBs must run 24/7 and allow for dynamic loading of new parameters.
- **Network Scalable High Availability** – single server is a single point of failure. HA support is required.
- **Seamless integration with ESB and other IT systems** – OT and IT systems must securely share information to maximize the value of your OT systems.
- **Native Protocol Support** – OT systems transact with protocols such as ICCP, Modbus, DNP3, OPC, and web services. OTMBs support a ripe environment to create reusable custom connections and legacy interfaces.

OTMB architecture allows for management of data flows and acts as a data engine – performing the critical transformation and loading functions required by outage management, distribution intelligence, and ISO/RTO markets. Rather than record and report data in the second range, OT systems are able to digest information in the millisecond range, and OTMB architecture enables high volume throughput to maximize the value and actionability of important system data.

Most importantly, OTMB architecture facilitates control of devices, which IT systems are incapable of doing as a result of the real-time requirements associated with operating critical components of the power grid. Smart grid architecture encompasses field devices, distributed generation assets, and advanced data usage; OTMB architecture enables the advanced integration and manipulation of these attributes.



OTMB architecture is established through the use of middleware like LiveData Utilities' RTI Server Platform. RTI Server Platform and similar purpose-built middleware platforms are off-the-shelf products that have been designed from the ground up to enable efficient, cost-effective Operational Technology integrations. Utilities employing OTMB architecture can expect significantly lower integration and operating costs when creating data networks that utilize an OT centric middleware solution. Middleware eliminates the need for much custom coding, in-house development, or modifying IT systems to perform as a data engine. OTMB architecture anticipates the dynamic changes of applications, data sources, and data consumers within the grid and provides lower cost of ownership through the system's lifecycle. Engineers utilizing OT middleware can integrate new systems and devices in a systematic, well-organized manner with the help of advanced graphic user interfaces.

OTMB uses operational protocols that existing operations applications already speak, and it interacts with each application with the correct latency, throughput, integrity, and dependability. Instead of relying exclusively on web technologies, OTMB uses high-performance communication protocols already in place across the grid and actively manages the flow and form of data across OT systems. It utilizes an organizing architecture to overcome the challenge of point-to-point integrations, so a utility does not have to solve the same problems to get systems to communicate, and it delivers complex data integrations in weeks instead of months or years.

Each day new technologies are changing the utility business. We are finding new ways to leverage data and are faced with an explosion of data sources that must be managed. Harnessing the power of data through OT organization is becoming a necessity for many utilities. At the same time, we must maximize the capabilities of field devices – ensuring consistent operation of distribution automation devices, maintaining service reliability, and improving transmission efficiency. OT systems keep our grids safe and allow them to function in a 'smart' manner.

Creating an Operating Technology Message Bus (OTMB) is one way to ensure that your organization will be able to cost-effectively manage and benefit from the explosion of data, systems and devices coming to the smart grid.

About the author

Adam Reiss is a Senior Marketing Associate at LiveData Utilities™, managing the marketing activities for utility products and services. With a background in institutional research that covers everything from investor statements to coral reefs, Adam has a passion for data and enjoys delivering actionable insights from unlikely sources.

Real Time Digital Simulation: Revolutionizing Utility Operations Globally

By Kati Sidwall

Faced with increasingly complex technology and a shift toward deregulation in the power market, today's electric utilities are under unprecedented pressure to improve the quality, reliability, security, and cost of the power that they supply to their customers. Real time digital simulators are a critical tool for utilities in this demanding and dynamic environment. For over two decades, utilities have used real time digital simulation to support their efforts in the study of power systems and their operation, the closed-loop testing of new equipment, and the strategic development of new protection and control schemes.

Before digital simulation was developed, analogue simulators were used to study electrical power systems and to test physical protection and control equipment. Analogue simulators were composed of scaled-down physical models of power system components, and inherently operated in real time. Although they were important tools at the time, particularly in the development and testing of HVDC and FACTS controls, they did have several drawbacks. The limited size and complexity of the network representation, as well as the high initial and operating costs, were among the disadvantages of this technology.

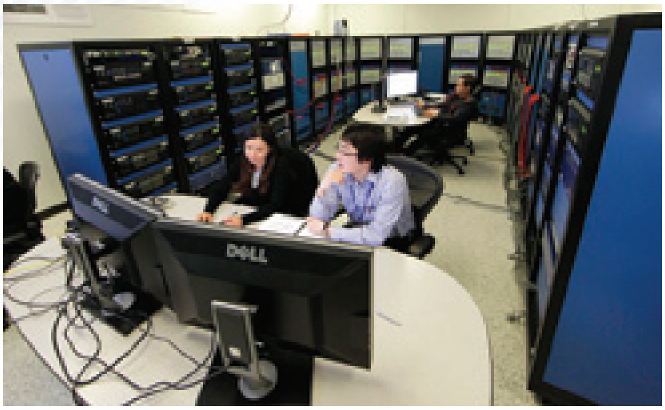
In the late 1980s, the available computer technology and modeling techniques made it possible to develop a digital simulation platform that operated in real time. Real time digital simulators emerged, combining the flexibility and accuracy of digital simulation with the inherent ability of analogue simulators to perform closed-loop testing of physical protection and control devices. Today, digital power system simulation technology has seen immense growth in the capabilities of computer processors, the sophistication and detail of component models, and flexibility in application. The modern digital simulator meets the demands of today's electric utility, and is capable of a huge range of applications, including renewable energy integration, protection testing via IEC 61850 communication, the implementation of wide-area measurement schemes using phasor measurement units, HVDC and FACTS scheme testing involving modular multi-level converters, exciter control testing and tuning, operator training, and black start studies, among others. This article will explore specific examples of these applications and how they're reducing system downtime, preventing equipment damage, and building a more favourable reputation for electric utilities around the world.

China Southern Grid (CSG), one of China's largest electric utilities, owns and operates the world's largest real time digital simulator, which is used for representing their AC-DC parallel transmission network. Using simulation technology, CSG is able to represent their entire transmission network above 220kV, including 8 HVDC systems, 1100 three-phase power system buses, 1400 transmission lines, and over 250 generators. Their state-of-the-art simulation laboratory combines simulation hardware and software with numerous sets of HVDC protection and control devices, which can be interfaced with the digital simulator in a closed loop.

The main applications of CSG's digital simulator are power grid operation analysis, system stability control testing, and the dynamic performance testing of HVDC projects. Dynamic performance testing involves the thorough testing of new HVDC projects before the technology is dispatched in the network. In 2013, CSG developed an interface between simulated modular multi-level converters and a physical control scheme in their laboratory. CSG's power dispatch department uses the simulation results to adjust system operation on a continual basis. To this end, CSG's simulator deals with many tasks related to power grid dispatching, including pivotal stability risk verification, failure analysis, and the determination of system operating strategy.

In the winter of 2008, southern China experienced a major ice storm which caused extensive damage to CSG's network, resulting in over 7,000 lines damaged and millions of customers without power. During this process, CSG's engineers used a real time digital simulator to help guide the restoration of their network. Following this, CSG officially identified real time digital simulation as one of their four key strategies for ensuring the security and reliability of their power.

Across the globe, digital power system simulation is an equally important tool to Southern California Edison (SCE), a utility providing power to millions of customers in the western United States. SCE owns and operates a large-scale digital simulator which they use for a wide variety of applications, including the testing of a centralized remedial action scheme, verification of the operation of phasor measurement units, and the closed-loop testing of line protection devices and schemes. The simulation platform at SCE is also used for interfacing to external equipment via various LAN-based communication protocols, and is capable of communicating via IEC 61850-compliant Sampled Values and GOOSE messaging, C37.118 protocol for phasor measurement unit data, as well as via DNP 3.0 and IEC 60870-5-104 SCADA protocols.



The real time digital simulation facility at Southern California Edison

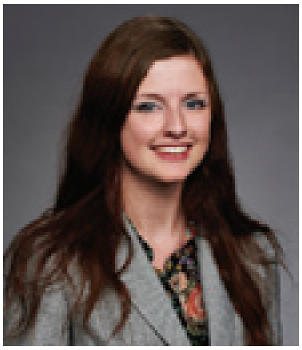
In Canada, Manitoba Hydro is using digital simulation to study the impact of a third HVDC bipole on the existing transmission grid in Manitoba, and to test the corresponding controls prior to implementation. A physical replica of the controls will be built and physically interfaced with Manitoba Hydro's digital simulator. In addition to HVDC controls testing, they have used simulation as a tool for testing exciter and stop/start sequence controls for a synchronous condenser, joint VAR controllers for a proposed and an existing generating station, black start generator controls, protective relays with point-on-wave breaker close ability, and transmission line protection schemes. Like the other utilities, Manitoba Hydro has developed detailed models of their electrical grid on their simulator.

Digital simulation is also being used extensively for HVDC scheme development and testing at Transpower, New Zealand's grid owner and system operator. Transpower made use of a digital simulation platform to verify the design and performance of the New Zealand HVDC Pole 3 upgrade project, commissioned in December 2013. The project replaced old mercury arc valve converters and associated control and protection systems with modern thyristor-based converters. Close to 2,000 unique functional and dynamic performance tests were carried out by Transpower's team using simulation equipment before commissioning and on-site testing took place. Transpower's simulation laboratory, like those of many utilities around the world, includes replica controls which are physically interfaced with their simulator.

Since the Pole 3 project was commissioned, Transpower's real time simulator has been extensively used to resolve issues related to the HVDC control and protection systems before implementing changes on site. For each end of the HVDC link, the replica HVDC control and protection system consists of a measurement system interfaced with outputs from the digital simulator, control and protection for Poles 2 and 3, bipole and station controllers, and a transient fault recorder. The software for all of these controllers was developed to run on both the actual on-site system and the replica system. A single Valve Base Electronics system is also included, which can be configured to work with either terminal, and is used for simulating valve misfiring. Lastly, Transpower's simulation platform includes LAN networks that emulate the on-site communications networks, making it possible to simulate communication faults between converter stations.

It is clear from these success stories that real time digital simulation technology has undergone significant advancements over the past two decades, evolving from an emerging technology to an industry standard tool that is used by over 100 electric utilities worldwide. Today's power system simulation technology transcends the traditional applications of closed-loop protection and control system testing and is a powerful tool that can be used for studying the integration of smart grid technology, wide area protection and controls, and renewable energy resources and their controls. As we move forward into a world with an even more complex technological landscape, simulation technology will continue to advance, helping electric utilities achieve reliable and secure operation of the grid of the future.

About the author



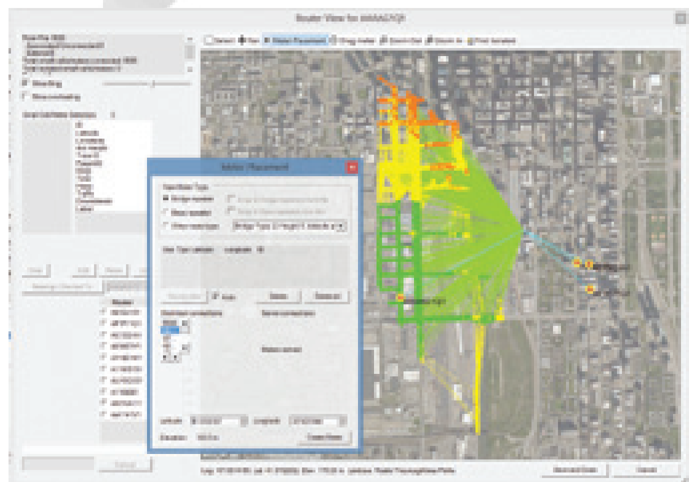
Kati Sidwall holds a B.Eng in Sustainable and Renewable Energy Engineering from Carleton University in Ottawa. She founded the annual Carleton University Green Energy Symposium in 2010. In 2012, she received the Canadian Solar Industries Association's Emerging Leader Award for her contributions to the Canadian solar energy industry. She currently serves as a Simulation Specialist at RTDS Technologies Inc. – the world standard for real time digital power system simulation.

Proper Modeling and Dimensioning of Large AMI Systems in Dense Urban Environments

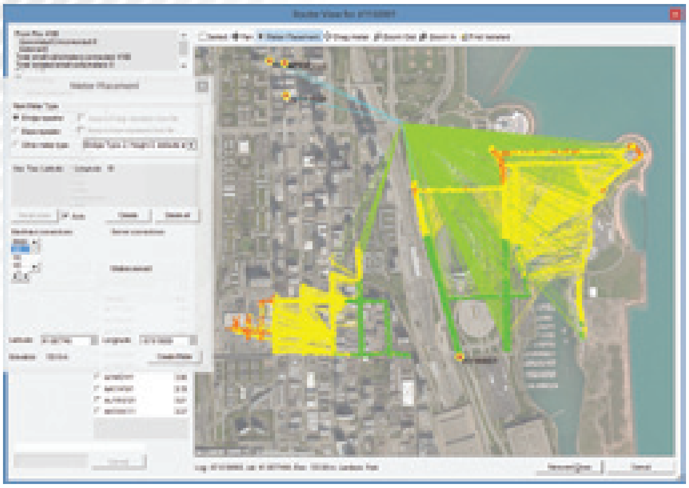
By Bob Akins

As wireless communication networks and the environments in which they are deployed continue to evolve, so too do the methods used in designing them. One major challenge continually facing utilities and vendors is the design of large mesh AMI networks, particularly those being deployed in dense urban markets. The inherently complex nature of these networks, combined with their changing architectures, presents many obstacles in designing a system that meets budget projections and performance requirements. This article will discuss the proper modeling and dimensioning of large-scale mesh AMI networks in complex urban environments as compared to traditional forms of network planning methodology.

When one considers wireless network design, it may call to mind wide-area coverage networks employing a 'tower site' type of system to cover a service area. To be sure, this system architecture may even work for some AMI applications being deployed in rural areas or areas with low meter densities. However, when we start planning networks consisting of hundreds of thousands or even millions of nodes in very dense urban areas, this approach quickly becomes impractical. First, a meter that is out of range in this type of network will require added infrastructure to be connected back to the network, thus adding great cost to the deployment. Second, a tower in this type of architecture would quickly become overloaded and the system would not meet its performance requirements. Due to interference considerations and spectrum restraints, it would not be feasible in this scenario to simply add more sites. By lowering the collector antenna height in urban deployments, we are limiting the interference range of each collector while maximizing capacity within limited spectrum resources. However, planning networks in these low-height topologies presents a new set of challenges. Among these is addressing a much more complex propagation environment containing many more potential sites than the aforementioned tower site systems.



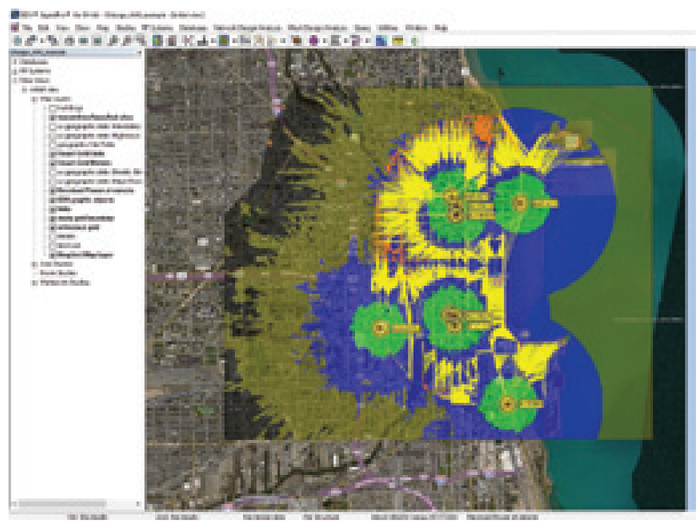
One of the most important aspects of planning a mesh network is the building of a 3D model of the environment in which the network will be deployed. This is typically done with terrain and clutter data and often times, clutter height and building data. As devices in these networks are typically mounted on assets 20 to 40 feet above ground level, it becomes obvious that environmental factors such as structures, foliage, roadways and other clutter considerations are going to play a major part in the performance of the system. As such, it is imperative to work with data that will provide an accurate representation of the environment. The examples in this article depict 1m/30m hybrid data from EGS Technologies, which contains data with resolutions as high as one meter. Hybrid data is made up of imagery from different sources to provide the highest resolution possible in the areas where it is most applicable. For example; you would most likely see higher resolution data in dense, urban areas and lower resolution in rural areas that are sparser in land use considerations and do not require a higher resolution database. With the cost of many high resolution databases difficult to justify, particularly when their benefit is limited to dense urban area, a hybrid database then becomes a very attractive option.



Even with high resolution data, situations found in real-world service areas such as limited or non-ideal mounting locations provide for many challenges in network design. One of the few propagation models that has served these type of urban environment predictions, ray-tracing, has historically not been optimal for large network design due to long study processing times. However, there are platforms available today that utilize GPU acceleration to offer ray tracing models that are orders of magnitude faster than traditional models. By utilizing detailed building data and taking into account all features of the environment, ray-tracing solutions offer site specific calculations that are highly accurate and detailed prediction of how signals will interact within complex environments consisting of any number of features and potential obstructions.

Further complicating matters in the design of these mesh AMI networks are all the potential links that must be considered. Because these mesh architectures consist of millions of possible communication links; with collectors linking to meters and repeaters, repeaters to meters and other repeaters, and meters to every other device etc., we know that it would not be possible to manually check every one of these possible links. Nor would it be feasible or efficient for a planning tool to make all of the possible calculations in a reasonable amount of time unless it has been calibrated to do so. EDX technology with the Mesh Network Module has been designed to not only run all of these calculations efficiently, but also allow for the engineer to impose their vendor specific capacity constraints on the various equipment, providing for further system design capabilities.

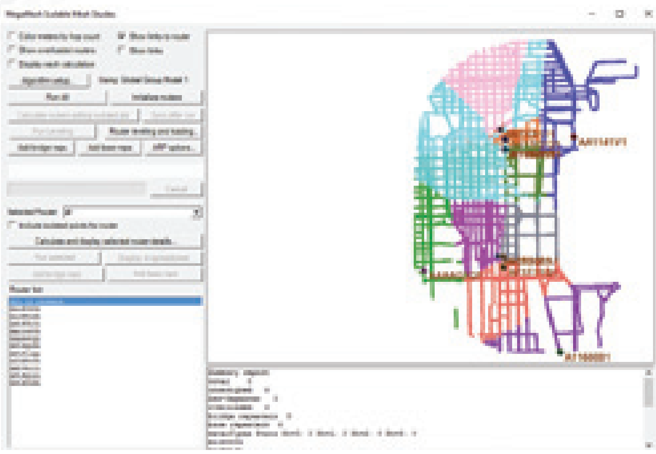
By considering these capacity constraints on the front-end of the overall network design, the utility or vendor will have achieved a more efficient and cost effective network design. This is in contrast to what you might see in the 'tower site network' application mentioned previously. A network such as this might employ a simple coverage analysis of the various network hierarchy layers. Typically, such a methodology would begin with the planning of the collector sites, located based on an average radius as determined by the largest distance a meter can be away from the collector and still mesh through the other network layers. After the collectors are placed, a coverage analysis would be performed to determine those locations where repeaters need to be added. When problems with these systems arise after deployment, the typical way of fixing them is to add repeaters where needed. This approach leads to system over-provisioning and therefore higher costs. But there are also consequences to the overall function of the network in this type of overprovisioning scenario. The performance of the network will experience degradation through increased mesh hopping and the associated rise of the noise floor as well as an increase in system latency. Furthermore, this type of design methodology will not consider individual equipment capacity aspects which can further contribute to decreased network performance. It will also not identify critical system nodes or take into account the RF performance of each individual link in the network.



A more effective design approach is to begin by ensuring a robust physical network layer. Because each AMI network will have capacity and hopping limitations, it is critical that the network design be aware and take into account these constraints. This is achieved with a thorough system design, using a tool that performs calculations for each of the potential links in the system. Another feature of this latest tool is that each link calculation considers minimum link power, hopping limits per device type, capacity limits per device type and performs calculations taking into account the 3D environment that has been modeled (terrain, clutter, building data etc) - creating a detailed RF physical layer. This design methodology ensures a robust physical layer and eliminates uncertainties among potential network links.

When it comes to repeaters it is essential to select not only the appropriate number of repeaters, but also the appropriate location. A repeater that is not properly located could easily become a main path for many devices, potentially causing a bottleneck in the network architecture and creating a single point of failure. A properly balanced system will feature the appropriate number of repeaters in the ideal location. These potential bottlenecks and single points of failure can be identified through a capacity constrained type study in a mesh link model.

There are several such factors to consider when locating equipment. And when we are dealing with very large networks consisting of a large number of devices, determining these locations is no small task. Fortunately, a fully featured tool contains many automated process that aid in these tasks.



A typical AMI network design begins with the importing of meter locations and potential candidate locations including poles, substations and/or street data. The technology in this latest planning tool distributes collectors based on these imported locations and automatically assigns the minimum number of collectors to cover devices based on receive sensitivity, maximum number of hops per device, and maximum router distance. Similar automated processes are also available for repeaters wherein the program automatically chooses the best repeater location based on potential repeater candidate locations. These locations can either be a predefined list of candidates that are imported into the tool, or an engineer may define a service area and let the program create a list of potential repeater locations. The tool also calculates connectivity in real time based on cursor location. With a map of your service area open in the program, you can move your cursor around the screen and in doing so, will have visualization of all the connections available based on the cursor's location. These features streamline pre-sales activities as well as the initial and subsequent system design iterations.

The design of AMI networks, along with the service area environments in which they are deployed, are becoming increasingly complex. As they do, it becomes essential to work with a planning tool that will properly plan, dimension and optimize these networks. EDX platform contains the features and automated process to take you through every stage of the network lifecycle.

About the author

Bob Akins is the sales and marketing manager at EDX Wireless. He is responsible for identifying and developing new opportunities across the wireless industry and actively contributes to not only sales and marketing, but also support and product development. In this role, Akins has worked with utilities, smart grid vendors and consultants world-wide as they plan and deploy AMI, distribution automation and other mesh networks. Mr. Akins joined EDX in 2012.

Harnessing UK's offshore wind potential

By Neil Beardsmore

The gust of wind in the UK is moving more than sailboats. It is electrifying.

Europe's windiest country is right on course to meet its clean energy targets of 15 percent by 2020 (Ashworth-Hayes, 2015). Not just a gust of hot air, wind power generation is growing from strength to strength, serving over 30 percent of British homes in 2015 (Murray, 2015).

In 2009, the UK made a commitment to the European Union to have renewable sources account for 15 percent of its energy consumption (OJEU, 2009). The definition of energy consumption includes the supply of heating and transportation. To achieve this overall target, Britain plans to have 12 percent of its heating, 10 percent of its transportation and 30 percent of electricity generation derived from renewable sources (Ashworth-Hayes, 2015). Renewable energy met over 18 percent of UK's electricity needs in 2015 approximately three percent more than it did two years before (Cuff, 2015).

Last year, UK's Energy Secretary, Amber Rudd proposed plans to shut all remaining coal-fired power plants that are unable to install carbon capture and storage facilities by 2025 (BBC, 2015). To compensate for this loss of capacity, plans were set in place to substitute it with more carbon friendly gas-fired power plants and renewable energy sources.

Although gas power was UK's main source of electricity generation, it is widely recognised across the energy industry, that renewable energy, in particular, wind, is an important part of the energy mix.

The force of the wind has been pushing its way ahead to meet the challenge to provide clean, affordable energy to British households. Just last year, 11 percent of UK's overall power supply was generated by wind power, a one and a half percent jump from the year before (Cuff, 2015). Equivalent to over 34 terawatt hours (TWh), that is enough power to electrify over eight million homes (RUK, 2016a). Whilst onshore wind technology is more established, wind farms are being increasingly developed offshore, where they can harness stronger, more persistent winds (Gridtech, 2012).

Milking UK's offshore wind farms

The British government looks set to provide support for offshore wind as a renewable resource. Last year, 17 wind projects were awarded Contracts for Difference (CfD) subsidies, the government's quest to support for renewable energy development (Weston, 2015). Only two of those projects were offshore wind farms. However, the investment towards wind energy, in particular offshore wind, is clear. Three CfD auctions are on the slate before 2020 – with offshore wind set to take centre stage (BVC Associates, 2016; Stoker, 2015).

In 2015 it is estimated that offshore wind contributed 18 percent of total renewable energy generation in the UK, which is roughly 5GW in production capacity (RUK, 2016b). This translates to approximately 15 TWh, which is equivalent to the electricity consumption of three and a half million homes (RUK, 2016b). The UK has the largest market of offshore wind in the world. It accounts for over half of the global wind offshore capacity followed by Denmark and Germany (Hill, 2015). As a result, offshore wind production in the UK is expected to double in 2020, reaching above 10GW, supplying between eight to 10 percent of UK's annual electricity demands. Global Data estimates that this will amount to over 23 GW by 2025 (Hill, 2015).

Currently the UK has consented to the development of 11 offshore wind farms, with a total capacity exceeding 11 MW (RUK, 2016c). One of the projects consented, and currently under construction, is Galloper Wind Farm Limited (GWFL).

Galloper Wind Farm Limited (GWFL)

Galloper Offshore Wind Farm, located off the coast of Suffolk, is an extension of the existing and fully operational 504 MW Greater Gabbard Wind Farm. The project was originally a 50/50 partnership between Scottish & Southern Energy (SSE) and RWE Innogy, with development of the project led by RWE Innogy. Following Financial Close of the project in October 2015 a new joint equity partnership between RWE Innogy, UK Green Investment Bank, Siemens Financial Services and Macquarie Capital was announced. At the same time 13 new financial backers were confirmed. The successful completion of the finance and project partnerships secured the future of the £1.5 billion offshore project, leading GWFL to be named as European Power Deal of the Year in Project Finance International (PFI) Yearbook and Top Deal of 2015 by Infranews.

The project, which has grid connection secured, is being progressed under the Renewables Obligation support scheme and RWE Innogy will continue to lead the development and construction of it. Initial onshore enabling works were carried out in 2014 and construction work recommenced following Financial Close in November 2015. The wind farm, which will comprise 56, six megawatt turbines, is expected to commence operations by March 2018.

Upon completion Galloper will be able to generate up to 336 megawatts of energy, equivalent to the approximate domestic needs of around 336,000 average UK households. Up to eight hundred jobs are expected to be created as a result of the construction and operation of the project.

Picking the right partners

With so much at stake, it is essential that the right partners are appointed for the execution of the project. From the turbines to the electrical systems and cabling, it was important for RWE to ensure that the right suppliers were engaged for the Galloper Wind Farm.

The teaming up of GE's Grid Solutions an Alstom and GE joint venture that brought together over 200 years of experience in advanced energy solutions with Petrofac, an oilfield service company with 34 years of experience made the ideal alliance to supply Galloper's turnkey power system.

With the oilfield experience Petrofac brings to the table its offshore expertise, tapping on its core strength in foundation design, fabrication and transportation and installation of the offshore substation as well as the logistics to support hook up and commissioning.

In return, GE's team of specialists will provide overall electrical system design, along with the onshore and offshore substation equipment including all related power transformers and gas insulated switchgear at 132kV and 33kV. Apart from that GE will supply two Static VAr Compensators, each connected to the grid by its own power transformer. This will provide dynamic voltage support to ensure grid code compliance, a stabilized power supply and strengthened transmission grid to ensure efficient connection of the new wind farm to the British transmission system. Incorporated into the scope of work are protection and control systems for the safe operation of the wind farm, including the telecommunications that is required between the onshore and offshore substations as well as the wider network. GE will also supply all ancillary and supporting electrical equipment such as auxiliary and earthing transformers, battery systems, back-up generators and low voltage systems.

This equal collaboration, where both parties are mutually invested, means that the success of project becomes a joint effort. Both Petrofac and GE bring valuable experience and expertise for the successful completion of the Galloper Wind Farm.

The future of offshore wind

With an 18 GW target installation capacity by 2020, the UK government is keen to back offshore wind energy projects (Hill, 2015). The development and investment costs of offshore wind farms are comparatively higher than onshore wind farms. However, in the long term, offshore wind farms have a lower generation cost due to the more powerful winds as well as the lower visual impact of the large wind turbines.

Several major wind operators have stated commitments to develop offshore wind farms in the UK. Dong Energy, UK's largest operator of offshore wind farms has committed to invest an additional £6 billion in projects by 2020 (Macalister, 2015). The company aims to proceed with the 1.2 GW Hornsea Project One. With 240 five-eight MW turbines installed off the Yorkshire coast, it is set to be the world's biggest offshore wind farm upon completion in 2020 (Dong Energy 2016). In the same breath, Scottish Power reaffirmed its decision to go ahead with the £2.5 billion investment into East Anglia One, one of UK's largest offshore wind farms in the North Sea (Hirtenstein, 2016).

The success of these projects largely relies on the availability of government subsidies, in order to allay the initial cost of construction. According to the telegraph.uk, the Hornsea Project One is expected to require £4.2 billion in subsidies over a 15 year period (Gosden, 2016). Underlying the need for subsidies is the ability of operators to keep development costs down. The right synergies and capabilities with the right partners have the potential to create the right conditions to harness the power of the wind in the middle of the big blue sea.

About the author

Neil Beardsmore is the North Europe Commercial Solutions Leader for GE's Grid Solutions. Prior to his role with GE, Neil worked for the National Coal Board (now British Coal) where he trained and achieved qualifications as an electrical engineer. After having several key positions in engineering – including the lead engineer for a British funded project in Indonesia – Neil moved to GECALSTHOM where he worked as an HV Systems Development Application Engineer, and later the Operations Manager for distribution projects and the development and execution of projects for rail, industry and utilities.

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Three Tips for Implementing Wireless Technology in Smart Grid Applications

By Germán Fernández

The seeds of the current smart grid were planted in the early 1980s with the introduction of electronic control, monitoring and metering. Originally a centralized, unidirectional system, the technological developments of the 1990s – digital control systems, graphic interfaces and software – changed the standard of the electric grid. Now, the thousands of highly interconnected, distributed generation sources and bi-directional networks possible within the electric grid have greatly increased the complexity of the electricity distribution process.

The distributed nature of the grid boosts efficiency and reliability, and establishes load balances between different generation plants, consumers and countries. But, with this added complexity, power engineers need real-time, bi-directional communication in order to support a modern power grid and employ reliable communications.

So, what should you keep in mind when working with a smart, modern grid? Wireless technologies are the most suitable method for deploying communications in densely populated areas with high amounts of distribution lines.

Here are a few things to consider in order to successfully implement wireless in smart grid applications:

- **Bandwidth**: Each device needs to remain stable to allow for services planning. To do so, the bandwidth needs to be consistent for all devices.
- **Latency**: It's important to know about any communication delays, however, time-critical applications in smart grids run on fiber, so latency shouldn't be a big challenge.
- **Security**: Networks should deter and monitor unauthorized access, misuse and modification, or denial of access, to both data and physical smart grid assets. Prevention mechanisms include incorporating multiple, threat-specific layers of defense onto the network, based on the behavior and context of each potential threat.
- **Reliability**: The network should function reliably under stated conditions for a specified period of time, specific moment or time interval.

The monitoring, analysis and control capabilities that come with a modernized smart grid improve the reliability, economics and overall sustainability of the production and distribution of electricity. But, with the complexity and interconnectedness of the grid, advanced communications are essential for enabling modern applications, such as grid visualization, real-time load monitoring, automated demand response, advanced protection, asset monitoring, smart metering, and consumer load control.

To ensure network integrity while working wirelessly in smart grid applications, follow these three tips:

- **Tip #1**: Use cellular communications for secure data transfer.

  The high-speed data access that comes with cellular communication offers a new way to reach local assets in remote utility facilities and third-party installations. The technology transfers data in a secure and reliable way – even through public networks – to utility substations, energy generation locations, utility offices and secondary transformation centers. Using cellular over public networks combines the benefits of high penetration frequencies with the already available backbone from the telecom utility's Internet connection.

  This 4G technology is ideal for smart grids, as it allows for two-way communication, remote monitoring and control of the grid; quick and easy installation; and broadband speeds. With 4G, you can remotely locate, isolate and restore power outages, thereby increasing the stability of the grid. You can also introduce other valuable services, such as condition monitoring, and new features, like video surveillance.

- **Tip #2**: Understand the implications of your unique operational environment.

  When working in smart grid applications, it's always important to consider how the operating environment will affect the network. Wireless technology can grant enhanced network access, mobility and interoperability, but in order to do so, the data networks need to operate reliably in harsh environments and withstand high electromagnetic interfaces (EMI), large temperature variations, shocks, vibrations and dust.

  Understanding the nuances of your unique operating environment ahead of time, and knowing which specialized features you will need for successful implementation, are critical for ensuring network integrity and reliability.

- **Tip #3**: Choose a complete solution to meet your particular needs.

Engineers need a complete, robust solution in order to successfully keep wireless network communications up and running. From the cables, connectors, patch cords and patch panels, to a broad portfolio of wireline and wireless switches for harsh environments, teams should have immediate access to all the network components they need to do their job. When choosing the right solution, look for these key things:

a. **Compact Ethernet port Long Term Evolution (LTE) router** for unlimited network connectivity.
b. **Integrated firewall** for maximum network perimeter protection.
c. Dual SIM card for network redundancy to ensure connectivity availability to a back-up network in case of primary network failure.
d. **Global Positioning System (GPS) for geospatial localization** to help maintenance teams easily locate a fault in the communications network and restore service to increase network availability.

With smart grid communication networks becoming more sophisticated and data rates increasing to support new applications, special performance features are required to ensure a high degree of network resilience. For smart grid engineers to maintain a steady flow of electricity throughout the grid, they need to ensure their networks stay up and running, and limit downtime. Implementing a complete wireless technology solution designed for smart grid applications is the best way to ensure this network availability.

About the author

Germán Fernández has 15 years of experience in the electric power industry, specifically pertaining to industrial Ethernet networking and telecommunications technologies. He is the global vertical marketing manager of power generation, transmission and distribution at Belden. He has managed power projects worldwide as a system integrator and brings a deep understanding of cybersecurity needs for electric power utilities to his role at Belden. He is also a member of the Cigre Working Group D2.40.

Sharing can help utilities fight cyber threats

By Ramesh Reddi

As a utility IT systems engineer and long-time cybersecurity consultant, I have many times walked into a utility control room, glanced at system dashboards and seen evidence of hacker attacks. I have seen intruders access utility systems, potentially revealing proprietary and critical information on utility assets and automation systems. And, I know it could help all utilities if such information could be shared quickly enough to thwart cyber criminals before they move on to the next utility target.

Utilities in the United States could certainly use the help. Here, a cyber-attack on a utility occurs on an average of every four days. That's the figure Congressman Randy Weber, R-Texas, told a House Subcommittee on Research and Technology last year.

Until recently, utilities were reluctant to report such attack, and they were concerned over two fronts. First, the information shared is not used in a timely fashion due to lack of real-time cyber-threat sharing technologies. Second, utilities had no legal protection against the liabilities that may result from sharing the cybersecurity information.

However, now that the Cybersecurity Information Sharing Act (CISA) of 2015 has been signed into law, those legal protections are now in place to lower the risk of sharing such sensitive data. More important, the U.S. Department of Energy's Cybersecurity Risk Information Sharing Program (CRISP) offers a timely and automated way for utilities to share their experiences and gain actionable information back. With CRISP, It's an all-new cybersecurity game for U.S. utilities. Here is how you can play to win.

Timely insight

CRISP is designed to give utility security professionals the timely information they need to identify, prioritize and coordinate the protection of their critical infrastructure and key resources. To be timely in the world of cybersecurity, information on threats must come in near real time and, through CRISP, it does.

Several government entities support CRISP. They include the:

- Department of Energy's Office of Electricity Delivery and Energy Reliability (DOE/OE)
- North American Electric Reliability Corporation (NERC)'s Electricity Sector Information Sharing and Analysis Center (ES-ISAC)
- Pacific Northwest National Laboratory (PNNL)
- Argonne National Laboratory (ANL)

Among these players, PNNL runs the CRISP Analysis Center. Utilities that participate in CRISP install an Information Sharing Device (ISD) on their network border, just outside the corporate firewall, then that ISD collects data and sends it in encrypted form to PNNL. The CRISP Analysis Center evaluates the data it receives from participating companies and, using government-furnished information, sends alerts and mitigation measures back to the participating companies about potential malicious activity.

The PNNL reports contain a combination of useful information, such as hostile IP address, DNS domains and other specifics that make these reports a very powerful addition to a utility's cybersecurity toolset. Better yet, this tactical and highly actionable data arrives via machine-to-machine exchange every five to 15 minutes, depending on the level of activity. These alerts can be pulled directly into the participating utility companies' intrusion detection or intrusion prevention systems to help prevent malicious activity.

The language of vigilance

CRISP is an early adopter of three new threat-sharing standards developed by the U.S. Department of Homeland Security. Structured Threat Information Expression (STIX), Trusted Automated Exchange of Indicator Information (TAXII) and Cyber Observable Expression (CybOX) are free specifications that help organizations automate the exchange of cyber-threat records.

Structured Threat Information Expression (STIX) is an XML programming language for describing cyber threat information in a standardized and structured manner. STIX characterizes an extensive set of cyber threat data. These include indicators of adversarial activity as well as additional contextual information regarding the threat, such as the cyber adversary's motivations, capabilities and specific activities.

Trusted Automated Exchange of Indicator Information (TAXII) standardizes the way information is exchanged by defining a set of services and message interactions that enable sharing of actionable cyber threat information across organization and product/service boundaries. Again, the purpose of the standard is to facilitate the detection, prevention and mitigation of cyber threats.

TAXII does not define trust agreements, governance or non-technical aspects of cyber threat information sharing. Instead, TAXII empowers organizations to achieve improved situational awareness about emerging threats, and it enables organizations to easily share the information they choose with the partners they choose using existing relationships and systems.

DHS initiated TAXII to simplify and speed up the secure exchange of cyber threat information. This standard eliminates the need for custom sharing solutions with each sharing partner, and it makes widespread, automated exchange of cyber threat information now possible.

Cyber Observable Expression (CybOX) is a structured language for the specification, capture, characterization, and communication of events or state properties that are observable in an operational domain. A wide variety of high-level cybersecurity use cases rely on such information, including event management and logging, malware characterization, intrusion detection, incident response, attack pattern characterization and indicator sharing. CybOX provides a common structure for relaying these observable circumstances, thereby improving consistent reporting.

With these new standards – plus the reduced liability utilities experience now that the Cybersecurity Information Sharing Act of 2015 has gone into effect – there are more opportunities than ever for utility professionals to bulk up their cyber muscle through data-sharing programs. What's more, CRISP isn't the only new cybersecurity game in town. To learn more please download the latest white paper from the Smart Grid Interoperability Panel titled 'Cybersecurity Information Sharing in Electric Utilities.' from the SGIP website.

About the author

Ramesh Reddi is currently working as Cybersecurity Consulting Manager at SGIP. Ramesh works with SGIP utility members in activities related to NIST cybersecurity frameworks, DoE Cybersecurity Capability Maturity Model, OpenFMBTM and Smart Grid Cybersecurity Committee. He was a key contributor to SGIP and NIST Smart Grid cyber security standards through his contributions to NISTR 7628. He worked on key smart gird cyber security projects at PG&E, Exelon and FP&L. The projects focused on cyber security of transmission, distribution, AMI, enterprise, industrial control systems and critical infrastructure protection, using NIST Cyber Security Frameworks, NERC CIP and NIST Industrial Cyber Security controls. In addition to his direct experience with utilities, he has many years of experience with vendors like IBM and HP. His current interests include cybersecurity information sharing, IoT and Industrial Internet Consortium Security Framework.

LightHouse Shines a Light on a Smarter Grid

With many utility companies left in the dark as to what is happening on their electric network, Erik Christian shares his views on what an agile and modern energy grid should look like.

It has been estimated by the U.S. Energy Information Administration that disruption to business continuity, caused by power outages and interruptions, cost as much as $150 billion a year. To reduce this burden, and to help our grid cope with the demands of today's digital economy, urgent modernization of the electricity network is required. In the same way our internet infrastructure is evolving to manage increasing amounts of data, so must our aging electric grid infrastructure evolve if it is to handle current and future demand.

In today's digital world it's hard to believe that millions of miles of electric distribution lines remain, for the most part, unmonitored, leaving many utilities blind beyond the substation and occasionally, quite literally in the dark.

The U.S author and award-winning engineer Dr. H James Harrington said: "If you can't measure something, you can't understand it. If you can't understand it, you can't control it. If you can't control it, you can't improve it."

At Tollgrade, we provide utilities and network operators better situational awareness, giving them real-time actionable intelligence on the status of their grid, and the ability to foresee and take action in situations that may lead to power outages in the future.

Over the last few decades, significant investment spurred improvements to the transmission and low-voltage areas of the energy sector. However, underinvestment in the distribution network continues to leave many areas of the grid vulnerable to faults.

Bridging the gap

An increasing everyday reliance on consumer technology and the growing penetration of renewable energy as a generation resource are just a few of the factors contributing to the pressure utilities feel to modernize their aging grid infrastructure. Today's distribution network is where 90 percent of outages occur, and according to an IEEE report, a significant contributor is failing equipment, which cause roughly 30 percent of all overhead power distribution outages. Grid operators lack adequate visibility of events on their network, forcing operators to react to problems on the grid rather than taking a proactive or predictive approach to equipment maintenance and outages.

Bridging the gap between yesterday's network and the grid of the future will require utilities to deploy solutions capable of not only solving today's aging grid challenges, but also evolve with the growing needs of the industry, while being sensitive to the associated costs. These solutions will need to be over-the air upgradeable, adaptable to future challenges without costing utilities valuable truck rolls and operating dollars to upgrade their monitoring system.

While the 20th century grid was focused on quickly solving issues as they arise, the grid of the 21st century will need to be more dynamic, identifying and fixing underlying precursors before they actually cause an outage or failure. To that end, some utilities and network operators throughout the U.S. and Europe have positioned themselves to be ahead of the game. These utilities now have the ability to analyze, detect and diagnose precursors to network faults, ensuring the actual fault never occurs. With a next-generation distribution monitoring platform, it's now realistic to foresee a time when there are no unplanned outages on the grid whatsoever.

Lighting the way forward

Today, more than 35 utilities across three continents, including DTE Energy, Toronto Hydro, Manitoba Hydro and Veridian Connections are using Tollgrade's platform to gain real-time information in the battle to predict and prevent power outages and equipment failures.

As we integrate more forms of generation from renewable energy sources like wind and solar into the distribution grid, UK distribution network operators (DNOs), including Western Power Distribution, Scottish and Southern Energy Power Distribution, and Scottish Power selected LightHouse to advance critical applications, including network planning, capacity monitoring, and active network management. As European countries continue to move toward a low carbon network with bi-directional power flow, having accurate real-time voltage and current measurements will be an essential requirement to monitor their network, ensure grid safety and speed the integration of renewable energy.

Smart grid sensors supporting integration of renewable energy

The canary in the coal mine – Waveform analysis

Many solutions exist today to give grid operators valuable data on the health of their network. Raw data, however, isn't enough in the fight to end power outages. To truly understand what's happening on their network, operators must have access to analytics software that leverages waveform analysis and pattern recognition to elevate data into actionable intelligence.

Capturing fault waveform data is crucial as it helps distribution engineers identify unusual, recurring events or power quality issues.

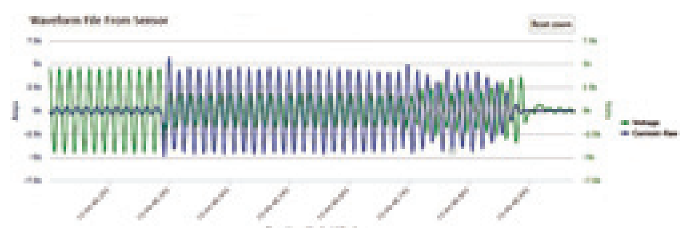
Traditional monitoring methods don't capture and scrutinize waveforms and tend only to alert utilities to malfunctioning assets well after, or in some cases not at all. Waveform analysis enables patterns of data to be identified as specific events. A powerful monitoring system should be able to distinguish hazardous from non-hazardous events. Repeated warnings of hazardous events often indicate problems with a failing asset, allowing engineers to be dispatched, make the necessary repairs and prevent a major outage.

One example of how predictive analytics can help utility companies keep the lights on is the work being carried out by Tollgrade and Detroit-based DTE Energy, as part of their commitment to 'Build a Predictive Grid for the Motor City' for the Clinton Global Initiative. The companies were able to identify and verify a category of events, called line disturbances, that act as an early indicator to outages. Line disturbance events are absolutely critical to establishing a predictive grid.

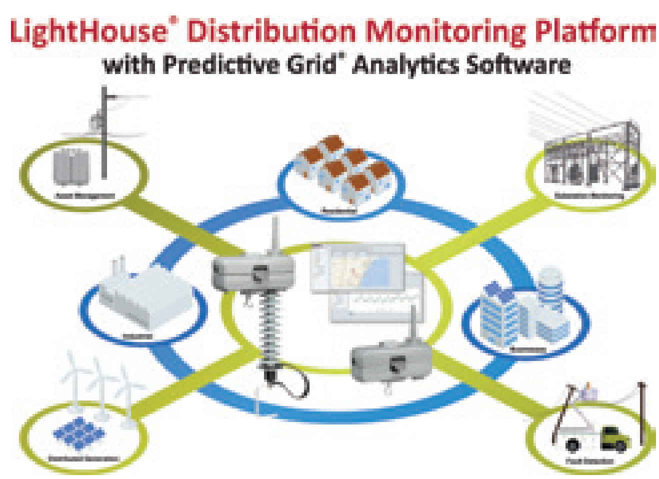
Line disturbances are nearly impossible for traditional monitoring solutions to identify and are more pervasive than one might expect in a utility's network. The published Predictive Grid Analytics Reports reveal that 84 percent of events captured on DTE's network were classified as line disturbances. Trending analysis verifies the correlation between line disturbances and outages, and monitoring line disturbances as a precursor to outages should become an industry standard.

Predictive grid in action

Although the evolution to a truly dynamic, predictive grid will take time, utilities deploying smart grid sensors are beginning to experience their full benefit today. A large investor owned utility in the northeastern United Sates provides a great real world example. This utility had only deployed smart grid sensors for a few months when they began receiving notifications of line disturbances on their 34.5kV network from LightHouse software. Over the course of several hours, an increasing amount of line disturbance events were detected in the same area of their grid. The data captured by the smart grid sensors provided line engineers with the exact location of the future fault. This saved the utility valuable time by avoiding having to patrol an entire 20-mile section of their power grid in the dark.



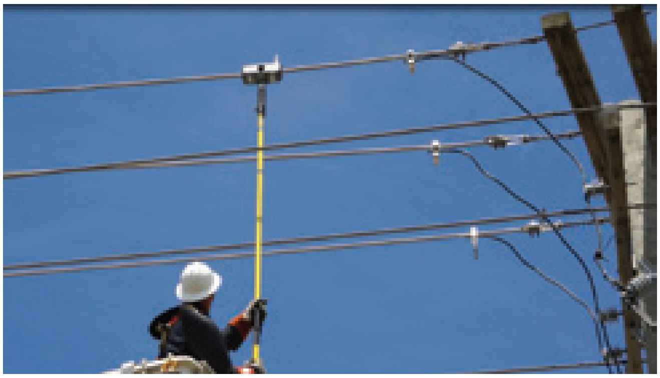
LightHouse fault waveform capture



LightHouse distribution monitoring platform

In this situation, traditional monitoring solutions weren't able to detect the issue. These precursor events went undetected by substation relays and SCADA devices, which of course failed to notify network operators of the impending situation.

Lighthouse MV Power Sensor installation



Hot stick installation of smart grid line sensor

Smart grid sensors directed distribution engineers to a substation, where they discovered a serious problem with a voltage regulator that was experiencing internal arcing and about to blow. The faulty equipment was quickly isolated and repaired. Had the voltage regulator ruptured, over 2,000 customers would have lost power for several hours causing an estimated 360,000 Customer Minutes Interrupted (CMI). A ruptured voltage regulator would also have caused a serious environmental and safety issue, with over 80 gallons of oil spilling out and polluting the immediate vicinity.

MV Power Sensor

Summary

Power outages and interruptions are a financial drain on our economy. New industry challenges, like renewable energy generation, are expected to significantly stress our aging distribution network over the next few decades.

The future of the grid, whether it's an extension of the Internet of Things (IoT) movement or some other paradigm, will mandate an expansive real-time monitoring platform capable of spotting issues before they occur. As highlighted in the latest Grid Modernization Index report issued by the GridWise Alliance, utilities need to quickly move away from a 'data starved' environment. How do utilities gain much needed visibility today, knowing that so much will change over coming years? They do so by investing in a software defined, over-the-air upgradeable solution capable of growing and evolving to solve future applications.

The best monitoring platforms contain affordable smart grid sensors, which in a single form factor combine highly accurate measurement tools and waveform capture, and analytics software capable of predicting outages and events before they occur. In this type of solution, utilities will finally find an ally in their quest to bridge the gap between yesterday's reactive grid and tomorrow's grid of the future.

ABOUT THE AUTHOR

As Vice President of Smart Grid, **Erik Christian** is responsible for Tollgrade's go-to-market strategy for smart grid in all key markets including North America, Latin America and Europe and drives marketing, product direction, business development and sales engineering. Prior to Tollgrade, Erik worked as an Investment Banker at Oppenhiemer & Co. and CIBC World Markets in New York City, specializing in Technology, Media and Telecommunications mergers and acquisitions, equity offerings and debt financing and at Columbia Capital, a Washington DC venture capital firm.

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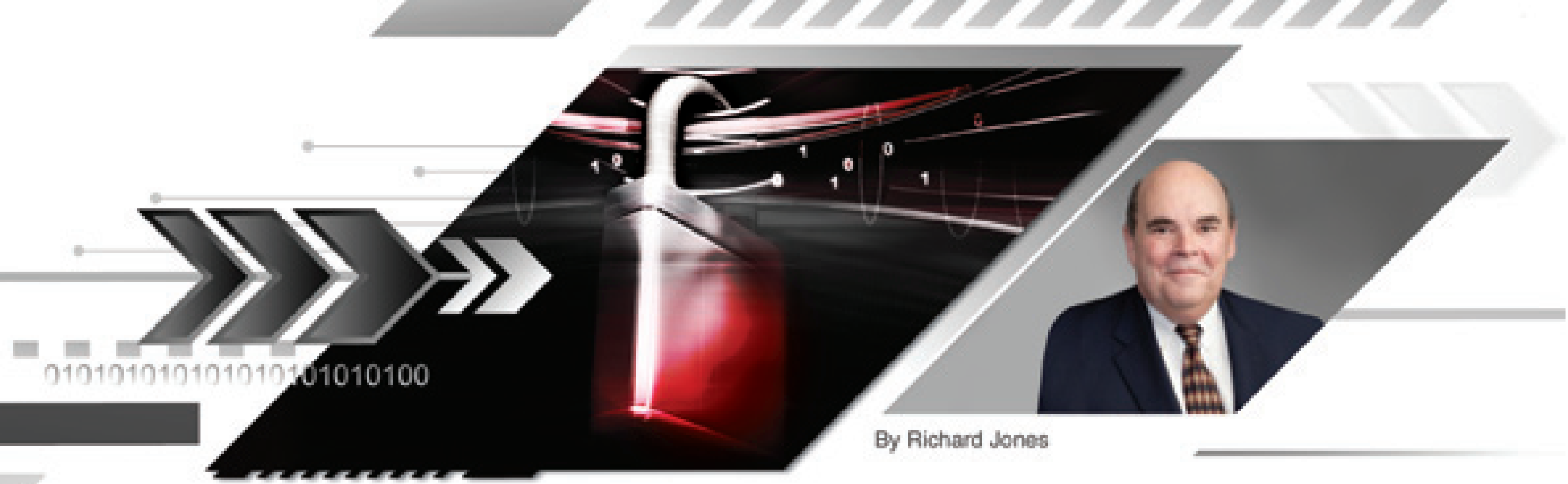

By Richard Jones

SECURITY SESSIONS

CIP Version 5/6 Compliance -- Don't Forget the Substations

The Good: A FERC Order providing an extension of time to defer the implementation of the critical infrastructure protection (CIP) version 5/6 Reliability Standards from April 1, 2016 to July 1, 2016.

The Bad: Establishing and maintaining cybersecurity in an industrial setting, such as the substations, is still extremely complex and difficult. The concern is always, "Am I taking the appropriate security measures, is my organization capable of sustaining this level of operations, and ultimately is the money being spent in appropriate places to enhance security?" as opposed to just making sure a utility complies with the literal meaning of the current standards.

The Ugly: Version 5/6 is steeped in the fear that a major cybersecurity breach, impacting the North American Grid, is just one hack away. Today, cyber terrorism is expected and it's a utility's responsibility to have effective protection and a tested response and recovery plan in place. The primary goal of Version 5/6 is to prevent, or at least minimize the impacts, of any cyber attack on the Bulk Electric System (BES) components of the North American Grid.

The Opportunity: To use this extension to not only continue to drive towards compliance and meet the letter of the law but to now take this opportunity to plan and deploy more optimum technology and process solutions that also meet the intent of the law – to improve the security posture of the North American Grid.

There Is No Substitute for Connectivity and Visibility into the Substations

With regard to CIP Version 5/6 compliance, there needs to be a full understanding of what works and what does not. The majority of utilities may not be confident that they have the right approach yet – even at this late stage. Many organizations will now target compliance by July 1st, but will compliance adherence be improved? Or still just enough? Will their security posture have been improved? Is it more sustainable? As of July 1, was this time used effectively?

The choice of appropriate 'security (compliance) management' tools, technologies and processes to be deployed at the substation and in the associated control and switching centers has been largely left to each utility. As illustrated here, the thoroughness of the solution deployed will be a function of that utilities current capabilities, risk appetite and accuracy of the protected asset inventory.

For instance, as part of its security operations each utility needs to determine to what extent the substations and the level of connectivity can or should support remotely handled password management and account management. Often this may require significant reconfiguration and perhaps device upgrades. Utility companies are struggling to succinctly address this question because the number of devices to manage at every substation is significant, and the variation in types of devices is overwhelming. Following the extensive inventory efforts at the substations that were demanded by CIP-002, there is a realization that a significant number of IEDs (intelligent electronic devices) will still require manual intervention for password management as opposed to being automatically managed by a tool. For each type of these legacy devices a manual protocol must be designed and implemented requiring extensive vendor coordination and compliance and awareness training for the substation support staff.

Additional considerations for security monitoring of these devices include:

- Are utilities looking at the appropriate type of alerts and events?
- Who is tasked to monitor all of this information?
- How is this data being analyzed?
- Is the assessment of risk based on local or regional knowledge?

Another example from the model relates to Asset and Configuration Management. Of course, Asset Management is a huge enterprise concern at most utilities, but now it takes on a very serious edge, as its effectiveness will impact the security and compliance of the utility. Utility organizations must now address the management of the asset-related information across the information and operational technology boundary. Even now as we approach the original target date, many utilities are still having an internal battle deciding which, and what level of granularity, information goes into corporate asset management systems versus into similar types of systems at a utility operating or business unit. The issue is not with regard to the federated data model, but simply how to coordinate the update of the information effectively in the industrially oriented, critical infrastructure environment that the substations represent. Simply put: as we understand the situation today, utilities are not comfortable that all of their current solutions are the right ones!

Because of this conundrum, the result may be a sub-optimal approach, where different versions of the same data are maintained on separate systems. Taking this approach, utilities will be still prone to preventable problems – if the wrong database is selected, an entire substation can be affected. The best solution resides with a properly targeted asset management solution – away from antiquated spreadsheets and multiple localized technology solutions which if not coordinated with the main asset management system, inevitably will cause many problems.

Exacerbating the asset management problem is the fact that at this point in time many utilities have chosen not to 'IP enable' their substations, even though it may make operations more effective. While understanding that this minimizes the number of CIP Version 5/6 compliance actions a utility needs to take today, this results in a blind spot or a lack of visibility into the 'hackable devices' at the substations, or the presence of unapproved devices and local malware agents. Not to mention that the intent of the regulation was to improve security at our critical infrastructure not to provide an open invitation and opportunity for cyber terrorists. The bottom line is that if this opportunity is taken the next set of regulations will be even more extensive mandates as to what the utilities need to do to protect the nation's infrastructure.

It seems that the security problems targeted for solution by CIP Version 5/6 may continue at every corner, and additionally the cost of compliance and an improved security posture is a major concern.

Consider the financial cost associated with achieving the cybersecurity capabilities that were the intent of full CIP Version 5/6 compliance. It is a significant monetary commitment for a utility to implement the needed IP connections and monitoring capabilities at every substation in order to ensure adequate protection. The fact is that most utilities cannot afford this, so they conduct a balancing act where the security breach risk is weighed against the operational cost of running and sustaining IP connectivity to every substation. On one side of the scale, utilities have a reduction in operational costs and complexity by limiting the number of compliance requirements to deal with, on the other side of this they are reducing the visibility into the substations for monitoring any unwanted activities, and in many cases also limiting the operational efficiencies a fully 'IP enabled' substation will bring.

But it's not all financial gloom and doom: utilities can leverage some of the existing communication infrastructure and also use this moment in time to improve and update outdated and unsupported technologies that may be deployed at some of their substations. While understanding that this cost is not insignificant, the cost of implementing the necessary IP to adhere to the security intent of the CIP V5 Standards at the substations is reduced if the facility is already connected to the main facility with fiber optics, and the long term operational, security and compliance benefits are definable and appropriate for action today.

Who Is Inside The Substations?

In addition, careful consideration must continue to take place to ensure the appropriate team is upgrading and replacing the devices at the substations. And while compliance demands that utilities need to know the background of every individual walking around their substations, it should be operational and security concerns that determines the mix of IT and OT capabilities and skills of these people. Changing the firmware in an operationally deployed relay or RTU requires coordination with system operations as well as an appropriate understanding of how to ensure that the unit is being put back into service appropriately. You cannot just pull the relay and shove it back into the rack.

Utilities are continuing to think through these issues and as before indications are they are not sure they have yet arrived at the right answer. Concerns remain:

- Should the general IT staff have access to a substation to install switches?
- Should the general IT staff have administrative access to our critical control systems and technologies?
- How is the company managing the operations and maintenance of the substations that are shared between the distribution and the transmission systems?
- How do you manage the actions of those who have access to the substations?
- What is the best governance and operating model for the ownership and management of the substation devices and other control systems?

Adding Some Perspective on Asset Management

From a security conscious asset management perspective, utilities need to take a good look at their device inventories and the required configuration data to effectively formulate a proper governance plan for substation and control system O&M. Oftentimes this is more difficult than initially perceived because asset management at utilities has multiple completely different sets of internal stakeholders with their own operational drivers, in addition to the vast array of information forms and genre of data to contend with. There is a significant investment of time, money and operational egos required to effectively address this issue and effectively 'normalize' the data to appropriately match all of their needs.

Unfortunately, many, if not most, utilities do not have the time to spend to properly understand all the data to the needed comfort level of each stakeholder to achieve consensus; it helps that most of this data is already electronically maintained in some form, so utilities have an identified starting point. However, simple compliance with Version 5/6 remains the current 'heartache' around the extended July 1st deadline. Given where we are today, for most utilities it has to be sufficient to make sure that the devices are configured correctly, governed by the correct firmware, or secured with appropriate measures and the mitigation plan is defined.

The "Low Impact" Substation Loophole

To fulfil the objectives of v5/6, the compliance (and security) of the low impact substations will still need to be addressed by April 1, 2017. The glaring issue is that most utilities in the U.S. have not even begun to consider this issue. The scale of the Version 5/6 High/Medium Impact work has been so significant that most utilities do not yet have the available resources to even begin to plan or consider the operational issues ahead for this effort.

In fact, when you look at the compliance requirements for the low impact category of systems and facilities, there are actually a very small number of requirements that are mandated to be addressed. For instance, as many of us recall from our frantic efforts throughout the past year, and the discussions above, the maintenance of an accurate and useful inventory of high and medium cyber systems and assets alone is often an Herculean effort. But in this case for the low impact cyber systems and assets this is not required. This may sound good, but this lack of a mandate may drive some additional sub-optimal practices.

Most likely we will now have additional sets of inventories, devices and configurational complexities to manage and upkeep for the lowly 'rated' groups of our protected assets. Purely from an efficiency perspective, let alone security considerations, shouldn't all of the information be handled and managed in the same manner regardless of currently defined impact levels? Threats change, and quite simply put you are only as secure as your weakest link. And if that link happens to sit on the same network as your high impact systems and assets – advanced malware and persistent attack methodologies may represent a severe security risk.

Additionally, because the 'operational' application of the advances in security and compliance are coming at a significant investment for the high and medium 'rated' facilities, it may just be business reality that limits their deployment to the low sites. Consider a utility that has 50 medium impact 'rated' substations. The same utility may have 300 low impact 'rated' substations. Evaluating the effort and costs of securing these low impact 'rated' substations with the same tools and processes starts out with a 6X multiplication factor and goes upwards from there as many of these substations may not have connectivity, may largely consist of electromagnetic devices not IEDs and may be in distant locations with minimal physical security.

The good news (from a cost perspective) is that utilities have this 'loophole' to make a judgment call as to how much security to deploy in addition to the minimal required compliance requirements.

The bad news is that most utility companies may have not even begun to consider this because they are still rushing to get the more highly 'rated' facilities and systems ready for the July 1st deadline.

The big question is: will they address the threats at the lower rated facilities adequately? Just being compliant will not necessarily improve the security posture.

In Conclusion

Finally, even if all the planets properly align on July 1st, there is still the 'stress test moment' to contend with. All the planning is completed and utilities have put the best systems in place, but the rush to meet the deadline may be so extreme that most of these utilities may still not have had the chance to test the security solutions and validate that they're operating properly with no impact to the reliability of the grid. In many cases, the effectiveness and efficiency of these new security systems and processes will have to be assessed, and more appropriate solutions defined and deployed to fill any gaps.

The CIP version 5/6 compliance efforts is more like a triathlon, just when utilities have completed one section of the race, there is another leg of the triathlon to accomplish, and version 7 is already in the works.

Utilities should view the compliance mandates, and in particular the extension to July 1, as an opportunity to do the right thing from a security perspective – that is FERC's intent. It is understood that it's next to impossible to be 100 percent secure, particularly with the utilities' scale and variety of assets and facilities; it all comes down to matters of degrees in reducing the risk of a breach. Ultimately, it's about finding and establishing the best-fit solutions, with the best combination of stakeholders that address your threat and risk profile across your operational assets and facilities regardless of compliance driven ratings. Finally, if utilities don't have the in-house expertise or available staff, there are consultants that understand the big picture and can help manage the associated costs and meet the needed level of resources. Maintaining the reliability and ongoing security of the North American Grid must continue to be the paramount objective of the utility.

ABOUT THE AUTHOR

Richard Jones, VP, Grid Security, for BRIDGE Energy Group, is a recognized thought leader in Cybersecurity, NERC CIP and general utility regulatory compliance and reporting with over 25 years of energy and utility industry experience providing business, technology, and management consulting based services. Prior to joining BRIDGE, Richard held a number of security leadership positions with the big 5 and industry focused consulting firms.

Protecting Electrical Transmission and Distribution Equipment from Animal-Related Outages

Guest Editorial 1

By Bernard Summerville, C.Eng. MIET

The transmission and distribution of electrical energy is a vital service that is required in order to keep our modern world moving in a way that we have become accustomed. Highways need to be lit up at night, businesses have to operate without interruption and essential services such as water treatment plants and hospitals must be able to handle the stresses of this ever evolving world, all of which require a steady and reliable supply of electricity. The system that supplies the electricity that we have come to take for granted is inherently vulnerable to interruption, which can cause outages. As the networks have become more complex and extensive to keep up with demand, more hardware has been installed particularly in overhead configurations. This can translate into an increased risk of animal related outages unless appropriate precautions are put into place to prevent such occurrences. Animal induced faults on transmission and distribution systems have long been a problem and records show that they have plagued engineers both in frequency and severity. Problems such as these do not disappear on their own and, in fact, statistics show that animal-related outages are becoming more and more prevalent. Aside from the obvious concerns about the reliability of the systems, such faults significantly escalate the equipment and maintenance costs associated with unplanned outages.

Terminations, conductors, busbars, and various other components in outdoor electrical transmission and distribution systems such as substations provide excellent climbing apparatus for wildlife that is naturally inclined to seek higher ground from predators or are in search of food, the consequences of which can be the interruption of electrical supply to customers, along with extensive and expensive damage to equipment. These problems are not solely confined to remote stations out in the country but are equally prevalent in suburban and urban locations as well. The vast majority of animal-related outages occur primarily at standoff insulators associated with buswork, the bushings of transformers, circuit breakers and capacitors. The studies on animal-related outages show that equipment in the voltage range of 5kV to 38kV is the most susceptible to such occurrences. This is because electrical clearances in this voltage range can be easily spanned by animals such as squirrels, raccoons, birds and the like, with the resulting damage to equipment becoming extensive and costly. A transformer bushing that is beyond repair and requires replacement is a typical example of serious damage caused by animals in transmission and distribution systems. Similarly, a damaged pothead, which needs to be replaced, creates an expensive supply interruption due to the required rejointing of the cable. Consider an animal initiated flashover on, say, the 15kV secondary side of a main transformer. The porcelain skirts of the bushing could be damaged to the extent that the entire bushing must be disconnected and replaced, this necessitates the dropping of the oil level in the transformer for removal of the bushing. The material, labour and downtime costs associated with such an occurrence can be extremely high.

The solution to animal-related outage problems

Having recognized that it is impossible to prevent animals by land or by air from climbing or perching on outdoor electrical equipment, the installation of insulated cover up is the first logical step in combatting the problems incurred by animal invasion of the system. Available today are form-fitting reusable insulating boots in an extensive range of configurations to cover every conceivable type of termination and connection associated with transformers, circuit breakers, capacitors and busbar systems. This comprehensive range of boots provides the ability to completely encapsulate any and all complex arrangements of busbars and terminations, preventing animals from damaging the system as all of the live surfaces are no longer exposed. Throughout the electrical distribution network, there is an increasing use of automatic reclosers. These are installed in strategic positions to enhance the network reliability by reducing transient electricity supply interruptions caused by lightning and storms. These devices are typically pole-mounted and their principle function is to maintain the continuity of supply. They are compact in design and are constructed with their bushings in close proximity to each other. This makes the device particularly vulnerable to animals spanning the gaps between the bushings, making simultaneous contact and causing interruption, here again, insulated cover up boots are necessary on the terminations to maintain the complete integrity of the installation.

Transformer station with reusable insulating boots encapsulating the 13.8kV transformer bushing terminations, busbar, busbar supports, and expansion joints

The insulating boots used in transmission and distribution systems must retain electrical integrity throughout their lifetime and from a practical point of view, they must be easily fitted and removed for maintenance procedures. The material must be formulated to withstand a wide range of climate conditions including exposure to extremely hot and cold environments, moisture and dryness, direct ultraviolet light and must also be inherently flame retardant. For these reasons the ideal cover up is form-fitting and needs to be manufactured from high-grade flexible insulation material to match the system voltage requirements.

The tolerance for loss of power supply by electrical utility customers has become less over recent years and will continue to do so as the world relies more and more on electricity for common day to day activities. Consumers are insisting upon zero interruption of supply and are calling for the appropriate guarantees of continuity. Investigations show that the supply authorities who have invested in animal control programs by encapsulating the vulnerable areas of their systems with boots can meet the demands of their customers and additionally, they are enjoying the benefit in the reduction of animal induced outages and equipment failures.

ABOUT THE AUTHOR

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Guest Editorial 2

Utility Integrated Microgrids

By Eric Stein and Farid Katiraei

Many electric utility companies are actively developing microgrid projects that will be integrated within the existing utility distribution system. The challenges and opportunities associated with a utility integrated microgrid will vary from utility to utility and site to site. Each utility site will have many unique attributes (e.g. system characteristics, customer mix), and variables (e.g. number of customers, generation types and sizes) that need to be carefully considered and properly evaluated as part of the project planning and design stage. The first step in the conceptual design process is to consider the objectives and goals for the microgrid. Although this is a critical first step in the design of any microgrid, the focus of the article will be on the challenges and benefits with integration of a microgrid within the larger existing distribution network.

Existing Electrical Configuration

Each utility distribution system has its own unique topography. The PECO Energy distribution system can be characterized as a mature metropolitan area network that evolved over many years. The evolution of this network has been driven by population and load growth in the Philadelphia area and technology changes over the years. As a result, many areas within the distribution network were overlaid with additional circuits of increasing voltage that reflect the load growth and technology changes. While this topography provides customers with increased reliability and resiliency advantages, it presents challenges for the implementation of a microgrid.

PECO partnered with Quanta Technology in 2015, to help advance multiple conceptual pilot designs that had been developed. An iterative process was utilized to evaluate, enhance, and develop each pilot into a high performance conceptual design. Feasibility and business case studies were developed for each pilot that identified benefits, performance, costs, optimal design configuration, and operating capabilities. PECO microgrid designs are focused on maintaining service to critical and public service providers during storms and other events that can cause lengthy grid power outages. These types of public service providers can support surrounding area customers with the critical services they need during long term grid outage events. To accomplish this goal, PECO decided on incorporating parts of existing feeders in a microgrid system boundary and design partial feeder microgrids, as defined in figure 1. Partial feeder designs are focused on maintaining service to a small geographic area that is fed from a larger feeder. The initial review of the existing distribution system electrical configuration in these areas quickly revealed that there were multiple circuits and voltages feeding these areas. This fact more closely reflects reality for many mature utility companies in established metropolitan areas and highlights the additional levels of complexity for partial feeder design in these areas. In contrast to building a microgrid in a green field, it was discovered that, in order to include the desired public service customers in a microgrid system boundary, there were varying amounts of electrical reconfiguration work required for each proposed area. The varying amounts of complexity and cost have a large impact on cost and feasibility of a project, which may result in multiple design iterations to further re-evaluate customer mix and microgrid size to manage cost versus expected value propositions.

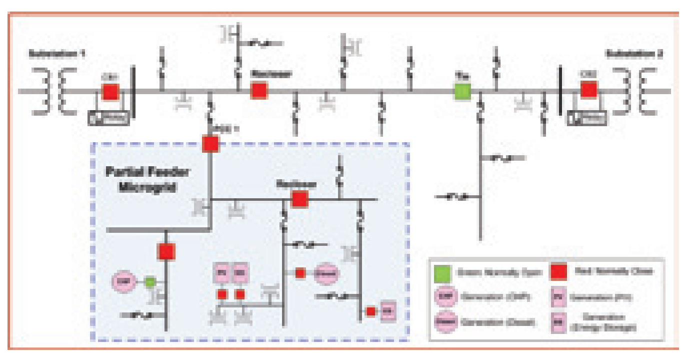

Figure 1 – A typical microgrid developed on part of a distribution feeder supplied from two different substations (partial feeder microgrid)

As previously mentioned, one of PECO Energy's primary goals is to increase resiliency in areas that have reliability challenges associated with large storm events. It is not a surprise to find out that these areas are typically supplied by aerial distribution facilities that are more susceptible to wind and ice storm events. While partial microgrid designs mitigate damage associated with the loss of utility supply between the substation and the microgrid, they will not be successful if there are existing aerial facilities within the microgrid footprint itself. Each project that was evaluated had some combination of aerial and underground facilities within the microgrid footprint. As a result, various amounts of aerial hardening work were identified to ensure that the microgrid would continue to operate in extreme weather situations, when it is needed most.

Reliability Considerations, Analysis, and Benefits

A significant effort was made by PECO and Quanta to evaluate and analyze existing reliability performance within each proposed microgrid footprint. Historical reliability data was collected for each microgrid footprint. Reliability performance drivers, such as cause and fault location, were analyzed to determine how much impact the microgrid would have on reliability improvement. Future reliability performance was estimated based on the learnings from this analysis to determine the benefits that could be achieved with the microgrid. As expected, the greatest benefit was in the area of minimizing outage duration (CAIDI). While there was some improvement in reducing the number of interruptions (SAIFI), this benefit is variable and dependent on the design and operating capabilities of the microgrid. This is primarily due to the fact that most on site generation would normally be off at the time of a grid interruption and would require some amount of time to start up and perform the load restoration process. Microgrids with simple load restoration schemes and battery storage will have higher SAIFI improvements than ones that do not.

Technology Integration and Interoperability Challenges

To achieve coordinated control and operation of the distributed energy resources and loads within a microgrid, various technologies and assets within the microgrid boundary need to exchange measurement data, information (setpoints and status signals), and commands among each other, or between end devices and a central control system. In a microgrid, real time monitoring, control and protection is the key technological enabler in supporting the autonomous operation and overcoming the technical challenges.

Some of the key technical challenges for utility microgrids include: transition between island and parallel modes of operation, protective relay and distribution system operation coordination, managing voltages and reactive power requirements on branches with bidirectional power flows, as well as fault detection and protection within the microgrid footprint. New control and protection schemes that are suggested as potential solutions to the above technical challenges are all requiring a reliable and fast communications infrastructure with focus on interoperability as the core function. Without interoperability, integration of the technologies and schemes becomes the most burdensome aspect of microgrid deployment and will add unmanageable risk in sustaining an island.

Enhancing the electrical distribution system with Microgrids

There are many options and benefits associated with microgrids. Some of the key benefits include: enhancing resiliency and reliability of the grid, leveraging the utilization of renewable resources, and facilitating the participation in ancillary service market, to name a few. However, there are many benefits that will enhance the overall operation of the larger utility macrogrid. Utility companies are best positioned to understand, coordinate, and control microgrids and other types of distributed energy resources to enhance and maximize the benefits for all customers. Potential utility applications include: targeted load relief, additional reliability contingency support, system voltage and frequency support, and deploying microgrid in areas that have load constraints and growing electrical demands. To leverage these capabilities and benefits, utilities will need to incorporate microgrid control within their existing distribution operations centers and integrate this control with their distribution management systems.

Closing Remarks

There are many challenges and opportunities for utility integrated microgrids. This article touches on a few of the technical and operational challenges associated with the development of a utility integrated microgrid project. Although, there are many utility connected microgrids in existence today, most have a limited capability to enhance and complement the macrogrid. As utility integrated microgrids proliferate, it is expected that the industry will focus on more mature use cases and benefits and develop a better understanding on how microgrids can benefit all customers in a utility service area.

ABOUT THE AUTHORS

Eric Stein is a Principle Engineer at PECO Energy with over 34 years of experience in generation and electric and gas distribution systems. He has a Bachelors degree in mechanical engineering from Villanova University and has Masters degree in engineering and organizational dynamics from Widener University and the University of Pennsylvania. Eric also served in the US Navy as Hull Maintenance Technician.

Farid Katiraei, Ph.D. is senior director of Renewable Integration and Microgrids for Quanta Technology. He has more than 15 years of professional experience in the areas of distributed generation interconnection, power electronics and modeling and analysis of system transients and dynamics. In the recent years, Farid has been the technical leads for design, development and testing of several pilot projects for utilities in North America involving renewable technologies, advanced distribution automation, energy storage and microgrids. Farid has received his PhD from university of Toronto in 2005. He is a Senior Member of IEEE, Steering committee chair of the international microgrid symposium, and active participants in several technical working groups and standards development task forces within IEEE, IEC and CIGRE.

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