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MAGAZINE

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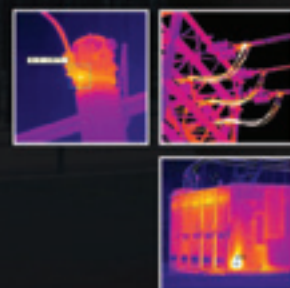


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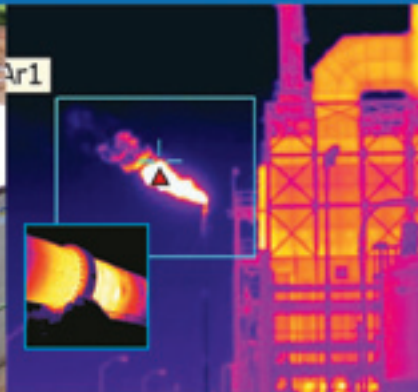
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POWERPOINTS

Brain Candy is its own Reward

At the risk of sounding like a broken record, DistribuTECH 2014 in San Antonio, Texas reinforced the reasons why I love this industry. The amount of brain-power on that floor was, as always, impressive and was a great feeding ground for my little gray cells. The very nature of the exhibitors made learning not only a tremendous pleasure, but also fun. Many of my meetings ended with a personal knock on my noggin with the silent affirmation – “This is fantastic stuff?”

Smart grid, big data, cloud, renewable technologies, infrastructure hardening, and thought leadership were predominant amongst exhibitors. The Ontario, Canada government is well aware of the value the show can bring and it too was on hand with several Ontario companies in tow all dedicated to transmission and distribution, from all generated sources.

One of the things I like to do is simply stand in a booth and listen to the conversations between exhibitors and attendees. The approach to problems, difficulties, and possible solutions is as unique and expansive as the personalities and knowledge of the engaged people. I can't profess to be able to remember all of what I hear but very often pertinent and interesting bits and pieces sink in.

Flying from Toronto's Pearson International Airport to the U.S. to get to the show started very early in the morning. In order to clear the customs hurdle that has been in place since 9/11 one has to be at the terminal at least three hours prior to wheels-up. My flight was for 6:40a which meant my being there at approximately 3:00 in the morning. A friend drove me to the airport through a raging blizzard and because we left a bit early I walked through the terminal doors at 2:30a. The American Airlines check-in staff wasn't due on site until 3:00 and as it turned out, they were weather-delayed and didn't make an appearance until four. One good thing about being that early is you are near the front of the line where I had the dubious pleasure of hearing about upcoming holidays to the Dominican, a golfing vaca in North Carolina, a junket to Disneyland, and a holiday planned at a dude-ranch in Texas.

As usual, like most places in Canada, the topic of discussion eventually turned to hockey and of course everyone has to hear about everyone else's favourite team and the hope it will make it to the Stanley Cup. One fellow stood out because his only luggage was a beaten-up gym bag, which was only partially filled. He was on his way to see his ex-wife in Miami. Curious about his lack of luggage, I asked him how long he planned to stay. Two to three weeks was the answer. I hope he had a drawer full of underwear somewhere otherwise he'd end up with just an elastic band around his waist after all that time.

Once the airport staff got their act in gear, we moved quickly through ticket check-in only to be held up yet again when the staff had to hustle everyone in a tour party to Miami to a waiting airplane. The snow just kept blowing and blanketing the aerodrome and dozens of us just kept standing in one place.

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While we were waiting I struck up a conversation with a fellow DistribuTECH attendee. He was operations and communications manager at one of the most advanced public utilities in south-eastern Ontario. We agreed to stay in touch – it's good to have as many quality contacts as one can muster in my job.

Once through passport control and baggage check, I headed for the security screening. Shoes off and on the conveyor along with jacket, belt, wristwatch, and pocket contents in a tray and then through the arch for me – done. Or so I thought. As I was waiting for stuff to come out of the 'oven' the security agent across from me started muttering to her colleague seated at a screen. I saw my jacket reversing and stopping for closer scrutiny. The agent looked at me and said, "Sir, is this your jacket?"

"Yes," I said matter-of-factly.

"Reach into that pocket and take out the contents and show them to me," she sternly said while pointing to that area of my jacket.

I reached in and immediately knew what this carry-on was about. I had inadvertently left my house keys there and a small Swiss Army Knife was attached.

"Take the object from the ring and show it to me."

I did as she asked.

"You can't take that on board." Her smugness was starting to piss me off.

"How do I get to keep it then?" I asked.

"You will have to take it outside to a designated area, put the object in an envelope, address it to yourself, and pay a fee for postage and handling. Then you must come back through customs," Her self-satisfied look was really getting to me.

I was already standing in my socks, holding my beltless trousers up and picking up my other valuables so wasn't too inclined to hang onto it. "Do you like this knife?" I asked facetiously.

No answer was the strange reply

"Who doesn't like a Swiss Army Knife?" I half seethed. "You keep the bloody thing. I hope you find happiness with it."

Thus ended my experience with pre-boarding clearance. Not once did the agent or her colleague utter the word 'knife' Swiss Army or otherwise.

Finally on board and after a lengthy wait on the de-icing apron, we unstuck over an hour late on our way to Dallas where I was to change for the flight to San Antonio. The gentleman next to me on the first leg was also on his way to DTECH. He was an engineer with a well-known electrical company and was a guest speaker on a panel discussing microgrids. Another excellent contact especially for our work in the magazine on renewable energies.

On the 400 kilometre short-haul flight to the home of the Alamo, I was given the aisle seat on the last row of the plane. The outside view was the port-side engine nacelle. I asked the gentleman next to me in the window seat to let me know immediately if he found he suddenly had an unobstructed view of the sky through the window so I could get my affairs in order. Luckily for everyone on the flight I was there to ensure all of the tri-head screws remained in place and tight on that engine cover. One can never underestimate the power of will and suggestion.

There is always at least one lousy traveller on every flight. If they're not constantly up and down like an outhouse seat checking on their belongings in the overhead bins, they're on an endless back-and-forth trip on the aisle to the lav. On that flight I'm sorry to say 'that person' was the guy in front of me. He couldn't change position without throwing himself against the seatback and he kept putting his feet on the bulkhead in front of him and pushing back. The worst of it was that my seat didn't recline because there was baggage stowed behind it against another bulkhead. Every time he drilled himself into his seat hoping to recline it further, the headrest portion nearly flattened my nose against my face.

My seatmate was also on his way to the conference. He was the owner of a company that designed and built the communications units that are used inside the new meters that help make them 'smart.' His sales were in the millions. His company also had the maintenance contract to service units from another firm. We struck up a delightful conversation and we too agreed to stay in touch. Luckily he had a sense of humour similar to mine as we both made stupid remarks about the view, missing engines, and amateur flyers.

No matter what, though, you can handle anything if you turn it into an adventure. My adventure started early and I wouldn't trade it for the world because if you have the right frame of mind, there's always a bright spot. In my case it was DistribuTECH and all that it offered.



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Schneider Electric Canada reached a milestone in its relationship with Habitat for Humanity Canada.

With a donation of \$230,000, presented to Habitat for Humanity Canada president Kevin Marshman, Schneider Electric has donated close to \$2M in equipment and monetary contributions to Habitat for Humanity Canada since 2004. Schneider Electric Canada has long been affiliated with Habitat for Humanity, participating in a number of builds, projects and providing support with cash and in-kind donations for more than 10 years.

The Midcontinent Independent System Operator, Inc. (MISO) broke ground on a regional operations center in Little Rock, Ark., signifying a continued commitment in the reliable delivery of least-cost energy to MISO members and their customers from the Great Lakes to the Gulf of Mexico. This action marks the next phase of the successful integration on Dec. 19, 2013, of the four-state electric grid spanning the southern region into MISO.

"A regional presence is important," said MISO's President and CEO John Bear. "This facility will provide the space necessary for us to build upon and develop a more focused approach to transmission system management and will result in more reliable and lower cost energy for end-use consumers."

Similar to the company's North Region Operations Center, the facility in Little Rock will serve as the command center for MISO's newly established South Region. MISO expects to hire roughly 50 employees with an average yearly salary of \$85,000 for various positions, including real-time operations, market operations, customer services, government and regulatory affairs, information technology and administrative support.

"Little Rock is an appropriate location for us," continued Bear. "It's a well-educated workforce, in a city with a great deal of experience in transmission planning and engineering."

"We've worked with higher education and the private sector to build a workforce that can bring more high-paying jobs to Arkansas," Governor Mike Beebe said. "This is another strong example of collaboration producing continued economic growth for our state."

MISO expects to spend \$22 million on its new facility in West Little Rock. The building is scheduled to be completed by the end of 2014 with an employee move-in date scheduled in spring of 2015.

"MISO is a great addition to Arkansas and is a testament that the committed partnership between the City of Little Rock and the Arkansas Economic Development Commission continues to attract topnotch 21st century businesses fostering job creation," said Little Rock Mayor Mark Stodola.

Dignitaries who attended the ceremony include Arkansas Governor Mike Beebe, Little Rock Mayor Mark Stodola, Arkansas Economic Development Commission Executive Director Grant Tennille, and Little Rock Regional Chamber of Commerce Chairman Gary Smith.

CG to Assist in Grid Expansion of One of the World's Largest Electricity Exporters ANDE Paraguay

Avantha Group Company CG signed a contract with the State Utility of Paraguay - Administracion Nacional de Electricidad (ANDE) for supply of 19 single and three phase transformers amounting to a total of 683.3 MVA, for expansion of the country's 220 kV Electricity Network. Paraguay is one of the world's largest exporters of electricity. It exports to neighbouring Brazil and Argentina. CG has been present in South America for the past two decades.

CG, which has a consolidated global manufacturing capacity of 95,000 MVA; 46,000 MVA in Asia, 31,000 MVA in Europe, and 18,000 MVA in North America, will manufacture these transformers in India and supply them in 3 lots. Spare parts, supervision of installation and commissioning, and on-site training, will also be provided.

This contract was won under a competitive international public bidding process. The Paraguayan grid has 1.3 million customers and approximately 32,000 kms of distribution lines. It has been growing at 4% p.a. since 2009. This contract represents the strengthening of 10% of ANDE's current transforming capacity.

ANDE's grid also faces difficulty due to distribution losses which are amongst the highest in the region. To assist in reducing those losses, and improving the grid's energy efficiency, CG recently also won a contract for the manufacture, supply, and installation of 30,000 Smart Meters in that grid.

As part of its global manufacturing capacity, in the America's, CG has a greenfield power transformer plant and a distribution and medium power transformer plant with a combined capacity of 10,000 MVA in Washington, Missouri, an 8,000 MVA Power Transformer facility in Winnipeg, Canada, and an Extra High Voltage (EHV) Switchgear & Mobile substation manufacturing facility in Sapucaia do Sul in the state of Rio Grande do Sul, Brazil.

This underlines the fact that CG is well positioned for serving the South American market and can provide its array of power Transmission & Distribution (T&D) products which includes Transformers, Extra High Voltage (EHV) equipment, Instrument Transformers (IT), Medium Voltage (MV) Switchgear, Gas Insulated Switchgear (GIS), Mobile Sub-stations, and Smart Grid devices, to Power Utilities and Industries in that region.

Commenting on the contract, Avantha Group Company CG's CEO & Managing Director, Laurent Demortier said, 'CG's global expertise in power transmission and distribution is now making its presence felt in the South American region too. We are proud to be involved in this major project with ANDE, and become a key player in their grid expansion and modernization programme. Our customers in the fast growing networks in that region can rest assured that we are fully equipped to meet all their demands with cutting edge quality and prompt deliveries.'



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Proof Positive that Energy Efficiency is the "Sweet Spot" For Congress and For Our Country

A Statement From Alliance to Save Energy President Kateri Callahan

Legislators from both sides of the aisle and both ends of the political spectrum agree on one thing: policies that advance energy efficiency in the U.S. are good for our economy, good for consumers and businesses, and good for our environment. The proof? Today (March 5th) the House of Representatives - which has been grid-locked on energy and climate issues - passed an energy efficiency bill with well over two thirds voting in favor.

Two visionary members of the House Energy and Commerce Committee Alliance Honorary Vice Chair Rep. Peter Welch (D-Vt.) and Rep. David McKinley (R-W.Va.) championed the legislation (H.R. 2126) that is estimated by 2030 to yield roughly \$640 million in annual energy savings as well as the creation of new jobs and significant reductions of greenhouse gas emissions. Importantly, these national benefits will be realized with little cost to taxpayers and no government mandates.

How can so much be achieved with this legislation? Energy efficiency is the cheapest, cleanest and most abundant national resource. And, the more our national leaders find ways to tap into this important resource, the more energy productive our economy will become. And, when we are more energy productive we are creating jobs and reducing emissions associated with energy production and use.

The Energy Efficiency Improvement Act delivers these important benefits to America by reducing energy use from the built environment, which is the largest consuming energy sector in our economy; encouraging energy efficiency practices in leased spaces; promoting energy efficiency in federal data centers; allowing the use of grid-enabled water heaters for demand response programs; and, spurring the benchmarking of energy usage in commercial buildings.

The Alliance believes that passage of this bipartisan bill will mark the beginning of a new era of bi-partisan cooperation on energy efficiency policies that will strengthen the U.S. economy, create jobs, enhance our environment and increase our energy security.

Energy grid investments keep power flowing to Alliant Energy customers

Upgrades will decrease length of outages and support economic growth

Alliant Energy's Wisconsin customers will continue to have power they can count on after more major investments from Alliant Energy. In 2014, crews are adding more than \$130 million in improvements to its energy grid in Wisconsin.

'Wisconsin customers will see our crews working on the grid from Beloit to Wisconsin Rapids, and from Prairie du Chien to Sheboygan,' said Linda Mattes - Vice President of Energy Delivery. 'As crews get busy, especially this spring, we ask drivers to slow down and be aware of work areas.'

This year, work on the energy grid will include upgrading power poles, wires, and transformers in communities, along streets and in neighborhoods. Crews will also work on the part of the energy grid that includes underground natural gas pipelines. 'All of this equipment works together so the lights turn on when you flip the switch, and so your furnace has gas to heat your home,' said Mattes.

Wisconsin customers are seeing continuous improvement in the energy grid. In 2013, for example, Alliant Energy crews added more than \$130 million in upgrades. In addition to making the system stronger, this work supports economic development. Businesses can expand or start construction quicker when the energy grid is ready for them.

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THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

How Utilities Can Batten Down their Operational Hatches in the Fight against Mother Nature

Rodger Smith, senior vice president and general manager, Oracle Utilities

We are in conversation with Rodger Smith, senior vice president and general manager, Oracle Utilities. He and his teams work tirelessly to establish new ways to mitigate Mother Nature's wrath by helping utilities keep customers aware and, in the aftermath of severe weather, help them get electric power restored as quickly and as painlessly as possible.

EET&D: Rodger, I think it is probably fair to say that utilities have placed a renewed focus on outage and storm management recently. What's your take on the situation?

Smith: Well, as we all remember quite well, the U.S. East Coast was hit hard by Hurricane Sandy, followed closely by a major Nor'easter, in October 2012. Together, the two events became known as Superstorm Sandy – the second-costliest hurricane in U.S. history.

Combined with other severe storms within the same timeframe across North America, Superstorm Sandy, as well as 2011's Hurricane Irene, resulted in a renewed focus on the resiliency of the electric grid, including questions about what can be done to better harden it against outages, and what utilities can do to better prepare customers for major outages when they do occur.

Obviously storm and outage management have always been a focus for utilities, but those major storms really forced them to push the pedal to the metal, so to speak, on how they'll better manage their future operations.

EET&D: I believe we both attended a panel discussion – including representatives from several utilities – at DistribuTECH in January focused on the lessons learned from Superstorm Sandy. What was the biggest thing that struck you about that particular session?

Smith: One of the main things that grabbed my attention was the packed room and engaged audience – which illustrated just how important outage management and storm preparation are for today's utilities.

A White House report¹ released last year noted that severe weather is the leading cause of power outages in the U.S. These severe weather events have prompted all utilities, even those that felt they already had strong storm preparation mechanisms in place, to reevaluate their approaches. While utilities can't promise their customers that they'll be able to completely avoid power outages during severe weather, technology and lessons learned from previous storm experiences can help utilities prepare for the next big storm, which is exactly what the session at DistribuTECH offered attendees.

Confirming those same sentiments, we surveyed utility employees at the show and 95 percent of respondents said they believe storm and outage management planning and preparation is either important or very important for today's electric utilities. Respondents also unanimously said that their utility has invested in storm management and outage preparation over the past year, and more than half (54 percent) described their investment as 'heavy' or 'strong.'

Bottom line, storm management is very much top-of-mind for the utilities industry these days.

EET&D: So what would you say is the best way for utilities to approach storm and outage management?

Smith: If we look for a moment at the 'Three Ps' of best practice – planning, preparation, and prevention – the latter P, prevention, is the most challenging. Complete storm-based power outage prevention would require rebuilding much of the electric grid, which is financially impossible. Planning and preparation, on the other hand, are continually aided by lessons learned, as well as the adoption of new technology and in-application data analytics. Nearly all respondents (96 percent) that took our survey at DistribuTECH said that their utility had taken steps to plan for storms in the past year, and 55 percent said one of those steps was making sure their outage management systems and processes are up-to-date.

¹ Economic Benefits of Increasing Electric Grid Resilience to Weather Outages, Executive Office of the President, The White House, August 2013.



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Smith: Utilities have access to more data than ever before, thanks to their smart grid investments. But are they doing all that they can to analyze the data available to them? By meshing weather forecasts and recorded damage from previous, similar storms, they can better predict potential damage, and do their best to prepare for it by pre-placing the right people and resources in areas most likely to sustain the most damage. It's clear that many utilities are already taking these steps, as 59 percent of our DistribuTECH survey respondents said that their utility integrates forecasts and damage reports to help prepare for storms.

Further, investing in strong outage management and distribution network management tools will provide utilities with full visibility across their entire grid to more swiftly determine outage issues while at the same time enabling them to operate safely, securely, and efficiently. Robust tools enable self-healing, autonomous restoration wherever possible, bringing customers back online quickly.

The key to success, however, is effective communication.

EET&D: Why would you say communication is so important?

Smith: Communication is critically important because no utility can prevent one hundred percent of outages, one hundred percent of the time. So, when outages inevitably occur, utilities not only must address the issue from an operational standpoint to get the lights back on quickly, but they must also ensure there is constant communication with stakeholders and customers to keep them up to date on the current status and progress.

For the most part, utilities understand this and are working toward it, but there's ample room for improvement. As a supporting point, 34 percent of respondents in our DistribuTECH survey cited customer and stakeholder communication as one of the most important components to managing and responding to outages. Of course, we'd like to see that percentage be higher, but the good news is utilities agree there is room for improvement: Not even half of respondents (49 percent) rated their utility's communication with customers before storm-related outages as good or very good and only 59 percent said their communication during a storm was good or very good.

For utilities that feel their internal or external communication needs improvement, I think it's best to look at some of their peers as examples. The best utilities go above and beyond by being proactive communicators with customers, using the

information they've gathered from weather alerts and previous storm data to distribute alerts on potential outages that may occur. Proactive communication is a good customer service practice and demonstrates that the utility is truly looking out for its customers' best interests.

Simply put – when the lights go out, customers want to know what the problem is and when their power is going to be restored. Effective communication helps keep customer expectations in check and reduces the amount of calls coming into the call center.

EET&D: Along those lines, it seems that social media and mobile channels have become a primary form of communication for most people today. Would you say that utilities are jumping on the bandwagon, too?

Smith: For the most part, I would say that utilities are moving in this direction, but I don't think the industry is completely on board yet.

We've talked to many utilities about their use of social media and the majority have agreed that ignoring these channels is no longer an option; utilities have to be in the social space because it's where customers go for information. To me, if utilities aren't communicating where their customers are, they may as well not be communicating at all.

Nearly a third of respondents (31 percent) at DistribuTECH said their utility provides weather forecasts and outage updates to customers via their social media channels (primarily via Facebook and Twitter). Furthermore, about a quarter (23 percent) said they send weather alerts and instructions to customers via email and text messages. Obviously there's still work to be done, but again, it's great to see utilities moving into the social space.

EET&D: Can you give some examples of how utilities can use social media and mobile channels to their advantage in the event of a storm?

Smith: Of course. In the event of a storm, utility customers can use their smartphones to upload photos of neighborhood damage and downed lines to social media sites, which provides utilities with real-time information that they can then use to dispatch the appropriate resources and personnel needed to resolve the issues.

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Pepco, for example, uses social media for 24/7 outage communication, as well as other customer outreach. A customer that tweets at Pepco about an outage will receive a response asking for the exact address of the outage, enabling the utility to provide specific details and an estimated restoration time. The utility also uses Twitter to send proactive messages, such as ones alerting customers that crews are working to restore power in various areas.

That's just one example of many, but it points to the fact that utilities are putting more of a focus on real-time communication and transparency with their stakeholders and customers. More and more service-driven interactions will

come through social media channels in the future, where consumers see greater possibilities for 24/7 two-way communication and rapid problem resolution.

This is a big deal because utilities have typically been a little slower to adopt these kinds of changes compared to other industries. Using social media effectively is new territory for many utilities, but those that embrace it will likely see improved communication and customer relationships.

EET&D: What do you see as the greatest challenge for utilities moving forward?

Smith: That's a tough question and it's truly difficult to identify just one challenge. I think the main thing that utilities will need to focus on is using all the data available to them and transforming it into real, tangible business value – both from an operational and customer service perspective.

I think another challenge for utilities today will be to find ways to treat customers as individuals, rather than as one large group. Customers expect the right information on the right channel at the right time from their utility companies, from crisis communication (such as outage management) to customer education (such as energy efficiency or safety tips). Utilities are beginning to rise to the challenge, moving to a more proactive communication approach.

Obviously, storms and outages are unavoidable and storm-related challenges will continue to test utilities' resilience. However, new technologies and information sources continue to emerge as potential assets for storm preparedness and response, and I, for one, am looking forward to seeing how utilities can capitalize on these resources to better serve themselves and their customers.

EET&D: It's been a pleasure speaking with you Rodger. By the amount of activity at DistribuTECH I can well imagine that you're run off your feet. It's also really good to know that companies like Oracle are at the forefront of working with and applying smart technology to look after customers both before and after a serious weather event.



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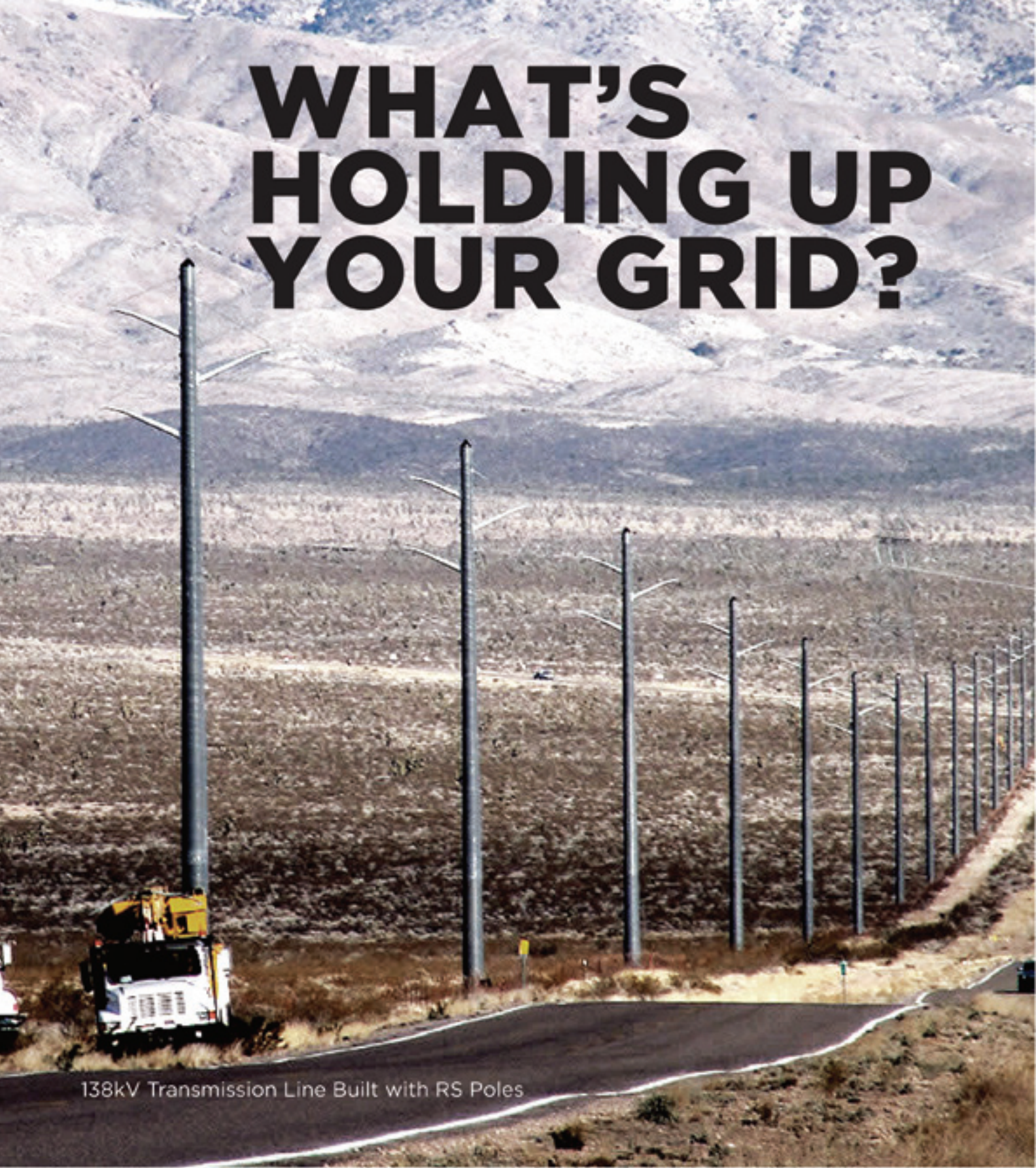
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Committing to Sustainable Utility Design

By Will Kirby, ENV SP, PE



Utilities are entering an era of change that could significantly enhance the sustainability of the projects we build. Stakeholder involvement and demands for more sustainable business practices are becoming more important, and for good reason. The population is currently depleting more natural resources and creating more pollutants than the Earth can sustain. Not only are resources becoming scarcer, but also the challenges and demands are becoming greater. Populations demand more power and more reliability, while the changing climate and severe weather systems result in greater strains on the aging grid. The path forward must change or the consequences for future generations could be drastic. The solutions will not always be easy, but with new tools like the Envision™ rating system assisting in the process, we can improve the quality of our practices.

State of Infrastructure

United States infrastructure was given a D+ rating ('poor') in 2013 by the American Society of Civil Engineers. A majority of infrastructure sectors in Canada received 'fair' to 'very poor' in 2012 on the Canadian Infrastructure Report Card. In America alone, it is estimated that US\$3.6 trillion is needed to be invested by 2020 just to get the infrastructure up to passing grade. In an age of reporting, transparency, and consumer relations, taxpayers and stakeholders will demand their money is being spent appropriately and efficiently. Company and utility reporting, such as the Global Reporting Initiative,™ provide methods to assist these entities in conveying to the public and stakeholders how they are implementing sustainable business practices. Many Fortune 500 companies are voluntarily deciding to participate in reporting because they know it adds value to their company. Those that aren't participating could likely be required to in the future. Indexes such as the Dow Jones Sustainability Index assess and value companies based on their commitment to this principle. Many individual corporations, such as Wal-Mart, have their own internal sustainability indexes and measuring tools. The Envision™ rating system can provide the guidance and framework to help utilities also achieve these business practices.

Enter Envision™

In 1998 the Leadership in Energy and Environmental Design (LEED) rating system was developed by the United States Green Building

Council (USGBC) to drive sustainable building design. To date, LEED has been applied to over 7,000 projects in more than 30 countries. It is the most accepted and successful green rating system on the market, setting the bar for all rating systems to follow in the coming years. Inhabited buildings were always the main target for LEED, leaving a major gap for civil infrastructure among other sectors. In 2012 the Institute for Sustainable Infrastructure (ISI), in conjunction with the Zofnass Program for Sustainable Design at Harvard, developed the Envision™ rating system to fill this gap. Utilities, public works, and civil infrastructure companies now had their answer to LEED. This isn't just a rating system to give recognition however, it is a design tool meant to provide guidance from concept to finished project.

Envision™ provides new guidance and metrics to gauge the sustainability of an infrastructure project by evaluating the contributions to the following five categories: Quality of Life, Leadership, Resource Allocation, Natural World, and Climate and Risk. The ultimate goal is to reduce, or in some cases reverse, the negative impacts created by a project. It has been designed to encompass all types of civil infrastructure, including transmission lines and substations. Previous rating systems have not covered all types of civil infrastructure, likely hindering the sustainable design development of the utility industry over the past decade or more due to lack of visibility, opportunities and incentive. Envision™ provides utility companies an opportunity to enhance project performance and sustainability without a major sacrifice to schedule or budget.

Opportunities for Utilities

While opportunities exist for new design and planning strategies, many utilities are already employing certain measures that fall within the best practices envelope. Many credits focus on stakeholder involvement and reducing negative impacts to the community, which is common practice for utilities on the front end of projects. Other credits may involve more extensive documentation and front-end work to earn points. If adopted during the early planning stages, it is anticipated that most projects can confidently earn lower-tier rating levels without making major adjustments to the standard project process and design. Projects that have complete team commitment at the earliest stages of the project, strive for innovative solutions, and target higher credit levels could earn top-tier rating levels (e.g. Platinum or Gold).

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Below is a chart reflecting anticipated point total ranges for low-achieving and high-achieving transmission and substation projects. As detailed in the figure below, the delta between high- and low-point totals is significant, indicating the great opportunity for high-performing projects. Some progressive utilities even want to see these kinds of studies conducted for past or current projects to give them an idea of how they are doing and where they can improve once they fully engage in the Envision™ process. The tool is readily available online to help companies evaluate a project that has already been completed.

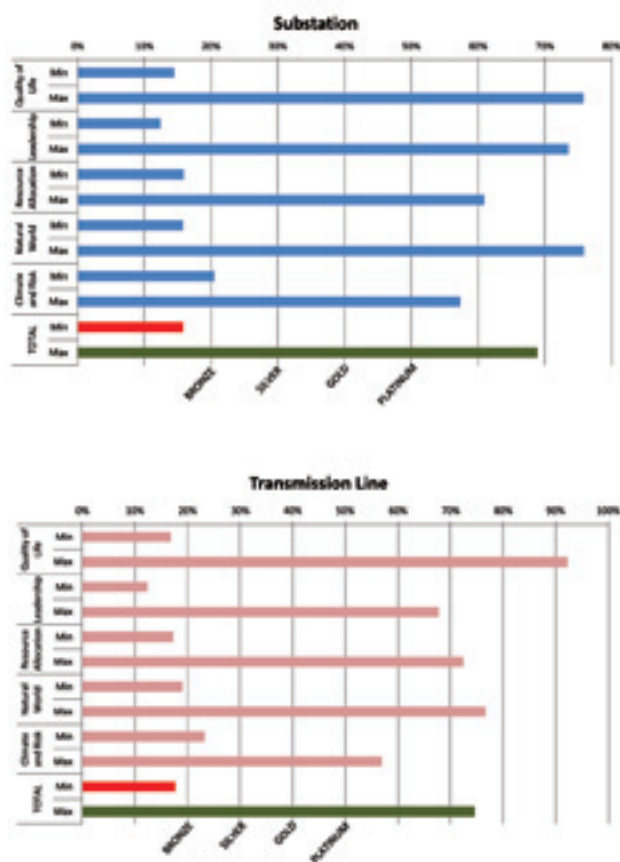


Figure 1 – Anticipated Utility Project Envision™ Credit Levels

At their core, all civil infrastructure projects are intended to provide for the health, safety and welfare of the population. Throughout history however, public infrastructure projects have not always been kind on the environment. It should not be a surprise that the credit categories – *Quality of Life* and *Natural World* – contribute the two highest point totals to the overall total upon which the project is rated. Utility projects have potential to score very high in both of these categories. Increased power transmission and distribution can improve community quality of life, stimulate growth and development, and build local skills. Not all credits in *Quality of Life* reflect what the project will change or affect, but rather how the project will minimize or preserve.


Utilities must focus on ways to preserve views and local character for example, while still managing to provide reliable electricity. *Natural World* credits also largely reflect how the project can reduce, avoid, protect, preserve, and control. New transmission lines and substations are largely built on undeveloped land, or green fields, meaning the impact to the natural world can be great. Transmission projects on occasion cut through farmland, forests, and other areas that can naturally create strong opposition among the public. Utilities are well aware of the efforts needed to optimize the route and engage the public. This is never an easy or cheap process. The Leadership category of Envision™ will help utilities engage the public early and often, and to foster a collaborative environment between the parties involved in the project. It is no secret that transmission lines and substations are not always popular among neighbors. Obtaining a shiny Envision™ Certified plaque for the project may not appease everyone, but at a minimum a utility can point to all the efforts undertaken to build a project that did everything feasible to result in a positive triple bottom line (economic, social, and environmental).



Rising waters and other changes in our natural world will provide increasing challenges for utilities.

Implementing the Envision™ Tool

In order to be most efficient, the utility needs to bring on one or more Envision™-credentialed team members (ENV SPs) that will guide the project through the process from concept to finished project. ENV SPs earn their credentials by completing training modules and taking an online test that reviews the credits and intent of Envision™. It is a requirement that a project applying for certification must have an ENV SP on the team. This team member will assist the group in assessing every portion of the project in hopes that it will extend the longevity of the infrastructure while reducing impact. The first project was not certified until late 2013, meaning that no project has been brought from concept to finished product under the framework by an ENV SP, thus the full intent of the system has yet to be realized.

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The cost of incorporating Envision™ into a project is anticipated to be low – compared to the overall project cost – and it should not significantly affect the project schedule. Utilities often focus on the upfront cost, but the ENV SP team members will try to assist them in looking at the project through different lenses regarding cost. Many hear the word sustainability and first associate the concept with cost. Companies around the world, including utilities, have proven that sustainable design can be accomplished while maintaining top-tier economic (and social) performance. In the 2013 Dow Jones Sustainability Indices, an energy company by the name of Energias de Portugal SA (EDP) was the utility industry group leader. It is no coincidence that EDP has a long history of sustainability initiatives and proactive approaches. These business practices are pervasive among the group's management; in fact, EDP monitors and evaluates their own 'Sustainability Index' on a quarterly basis. As seen in the following graphic, EDP does not seem to be underperforming due to this business model which has evolved over the past few decades. Rate payers and stakeholders are beginning to demand these sustainable business practices from their utilities, and Envision™ will not only assist in these practices, but also provide recognition for their efforts.

Sustainability Scores

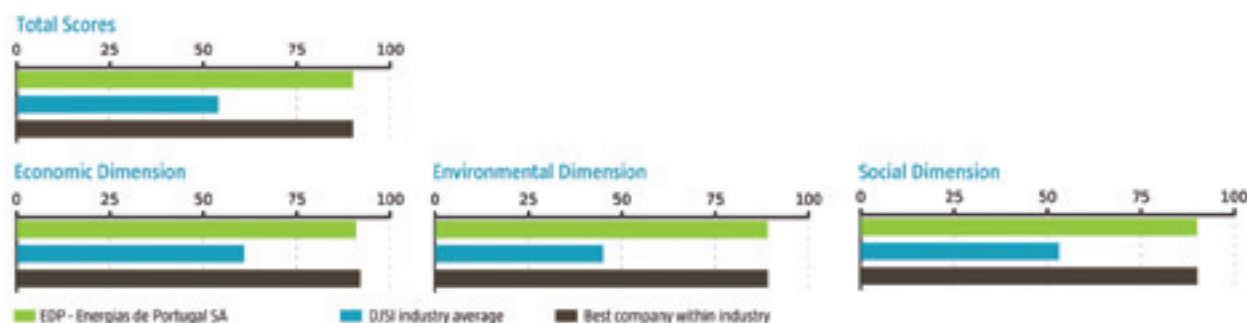


Figure 2 – Dow Jones Sustainability Index for Top Utility Group Energias de Portugal SA (Courtesy of Dow Jones Sustainability Indices)

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Changing the Status Quo

Recent changes due to the Federal Energy Regulatory Commission (FERC) 1000 order may shake up the industry, notably to the right of first refusal policy. "The rule also promotes competition in regional transmission planning processes by removing from FERC-approved tariffs and agreements a federal right of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation," stated former FERC Chairman Jon Wellinghoff in a 2011 press release. Now that utility companies will not get first shot at all projects within their region or service area, they will inevitably see more competition from innovative developers and other utilities. The overall goal is to keep increasing reliability for existing customers while delivering low-cost power to new markets, including renewables. Envision™ will help utilities provide the value to keep growing their business and stay competitive in this changing landscape. Creativity and innovation will happen at the front end of the planning process. In the past, utilities might not have always been addressing the right project, which is something that the system also strives to address. Perhaps the solution is not a new 60-km transmission line, but higher capacity storage or a micro-generation unit. Utilities should not only be asking if the project is done right in the end, but also if this is the right project to begin with.

Moving forward as a society, the electric grid is arguably the most critical component of public infrastructure. So many things people do every day are entirely dependent upon being able to plug into an electric outlet. The design of the electric transmission infrastructure system needs to be progressing and innovating at a comparable pace as the rest of society. Much of transmission and substation infrastructure has outlived its useful life and is based on very mature technologies that have changed little over the years. Ample opportunity exists for innovation in many areas within electric transmission, and specifically in the area of environmentally conscious design. The competition created by FERC 1000 highlights and emphasizes these opportunities and incentivizes stakeholders to take advantage of them. The future is very bright for stakeholders involved in the transmission and distribution industry. As more and more opportunities present themselves, innovation is a natural by-product. The opportunities in the sustainability arena are clear. The rating system has already created a program that guides a project in the direction of a more sustainable product. Emphasis on sustainability is a valuable and noticeable way to stay ahead of competition, satisfy shareholders, and add value to business. The Envision™ system is a tool to guide utilities down the path to achieve that value.

About the Author



Will Kirby is a Staff Transmission Engineer in the Transmission & Distribution global practice at Burns & McDonnell. He has almost five years of experience at the company working on overhead transmission and distribution line design. Will earned Bachelor of Science degrees

in Civil Engineering and Architectural Engineering in 2008 from Missouri University of Science & Technology and is a registered professional engineer and an accredited Envision™ Sustainability Professional. Will has been working on sustainable design studies and efforts for the past three to four years.

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From Research to Action

Communication Research and Actions to Enable the Future Electric Power System

By Matt Wakefield, Director, Electric Power Research Institute (EPRI)
Joe Nowaczyk, Director, Salt River Project (SRP)
and Jason Handley, Manager, Duke Energy

Introduction

Customer satisfaction continues to be a key priority for the electric power industry and two key drivers for customer satisfaction are reliability and affordability. Many emerging technologies, sensors, and intelligent devices being deployed on the grid are helping to improve both reliability and affordability, but to successfully enable these technologies a supporting infrastructure must be in place. A very important enabler is communication technology that provides the necessary connectivity to not only the devices, but also utility workers.

Over the last six years many large-scale smart grid demonstrations around the world have been applying, evaluating, and demonstrating a wide range of technologies to accelerate the commercialization of electric grid technologies. EPRI's involvement in these projects along with in numerous other demonstrations around the world has identified communication standards, availability and performance as one of the most significant and common gaps to overcome to achieve the goals of a smarter grid.

To provide just a flavor of emerging applications, their benefit and the associated communication challenges, here are several examples:

Application	Benefit	Communication Challenge
Transmission and Distribution Asset Health - Deployment of communicating sensors to monitor the status and health of grid assets	Prediction of failures before they occur and extension of life for healthy assets to avoid premature replacement costs	Having single-use non-standard, non-interoperable communication interfaces in devices; Built-in communication technology becoming obsolete before the asset does; Cyber security attack surface-area increasing with devices deployed
Distribution Automation (DA), Conservation Voltage Reduction (CVR) and Secure Remote Substation Access - More intelligent and automated devices being deployed to improve grid operations	DA improves reliability, CVR improves distribution system efficiency and secure remote substation access improves operational performance and maintenance.	DA often requires fast communications; CVR requires connectivity to sensors for voltage and capacitor banks and line regulators for operation; Being able to securely access remote substations and devices
Integration of Distributed Energy Resources (DER) - Managing and controlling demand response, solar, storage, EV's, microgrid's, etc.	By managing the resources, they can be a grid asset vs. a burden and enable higher penetration levels	Successful integration requires implementation of standards as well as requiring the associated connectivity to the resources
Workforce Management - Providing utility workers with a variety of applications such as storm damage assessment and work order management.	Automates manual processes, reduce the time for restoration after storms, enables mutual assistance crews	Requires a supporting communication infrastructure and standardized application and security protocols to maximize benefit
Advanced Metering - Automatically perform meter reading and emerging distribution operations analytics and applications such as CVR	Leverage meters as sensors for distribution applications and other innovations beyond meter reading	Advanced metering communication infrastructures have not been designed for advanced functionality

Each of these examples can be individually addressed very effectively and in many cases that is exactly what's happening; however, this is a problem. As each operational or business need is identified, a survey of available communication systems is performed and if there is not an in-place communication infrastructure that will meet the needs, a new one is deployed. As a result, this 'accidental communication architecture' is developing. We know communication needs are increasing, communication technology is rapidly evolving, most existing utility infrastructures will not meet future needs, and advanced communication infrastructures can be cost-justified by a single application. With all these factors, it is increasingly important to have a communication technology strategy that takes these factors into account to meet the future electric grid operational needs.

EPRI is addressing these research areas in a number of ways. One project addressing many of these challenges is the [Field Area Network \(FAN\) demonstration](#). The FAN concept is a ubiquitous, high-performance, secure, reliable network to meet the needs of a broad range of smart grid applications that historically have been performed by separate communication infrastructures. This in turn may produce measurable impacts on the power system. These impacts provide value in the form of reduced utility and customer cost, increased reliability, improved power quality, or reduced impact on the environment. The FAN system itself does not produce these benefits, but can enable all of them. A FAN system with no applications has only a cost, but a FAN system supporting multiple applications can be very valuable.

The following two examples of communication technology strategies from SRP and Duke Energy provide a glimpse into the future of utility communications based on their individual needs and visions.

SRP and their Field Area Network

The SRP power district is one of the nation's largest public power utilities providing electricity to more than 970,000 retail customers in a 2,900-square-mile service area that spans three Arizona counties, including most of the metropolitan Phoenix area. In addition, SRP delivers about one million acre-feet of water annually to a 375-square-mile service area and manage a 13,000-square-mile watershed that includes an extensive system of reservoirs, wells, canals and irrigation laterals.


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For SRP, the FAN is a strategic capability that provides benefits for existing systems and planned upgrades by unifying a variety of single-purpose communications systems. It provides additional benefits by enabling an additional set of applications that would otherwise be impractical due to technical limitations or cost. The set of applications that SRP evaluated for the FAN include Distribution Feeder Automation, Capacitor Control, Electronic Systems Monitoring, Water SCADA, Water Delivery Gate Keeper, Video, Network, and Advanced Metering is being considered for future evaluation. The project developed the data and analysis to answer the questions: “Should SRP implement a FAN?” and “What type of FAN architecture and technology should be deployed?”

Duke Energy and their Digital Grid Vision

Duke Energy defines the digital grid as an end-to-end energy Internet powered by two-way digital technology. It is comprised of an Internet Protocol (IP) based, open standards communication network that allows for automation and the exchange of near real-time information as well as enabling the adoption of new technologies as they become available.



- Exclusive use of services from one or more public wireless carriers for the Field Area Network
- A private Field Area Network deployed and managed by SRP
- A hybrid combination of public and private Field Area Networks
- A network shared with public safety in the 700 MHz band

This digital grid network must have the bandwidth, embedded sensing, control and software, both distributed and centralized, to collect, organize, and analyze an immense volume of information. This requires the two-way bandwidth to link the real-time events detected with the appropriate grid devices that will respond to those events both grid-wide and locally. This enables utilities to address load and congestion, system stability and equipment health or outages in a more efficient manner and improve reliability.

This network will require an integrated implementation strategy that adheres to a common infrastructure model. An incremental and disconnected approach is more costly and ineffective.

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From Research to Action

The communications network must make it easier to adopt new technologies and solutions, allowing Duke to take advantage of advancements in storage, micro-grids and distributed generation as well as adapting to future energy transformations. This network will need to support local intelligence that provides autonomous, decision making controls as well as centralized notifications, overrides and inputs with situational awareness from multiple sources. The autonomous operations of the devices will need to take in to consideration factors that include: a customer's preferences and actions, equipment operating parameters, weather, equipment failures, local and more wide-spread grid activities such as actions in other homes, neighborhoods, cities, and states.

Duke's communications architecture in Ohio and its smart grid field test area in Charlotte connects public carrier WAN access to each distribution transformer. Simultaneously, the communications node serves as a communications gateway to manage and operate various smart home, smart meter, and distribution devices.

No single technology is capable of meeting the needs of or providing the coverage necessary for the electric utility service

territory. A communications node designed to have the options of utilizing wireless and wired connectivity can support three types of communications:

- **Wide Area Networking (WAN)** –The network connecting the communications nodes to the enterprise data center and back office.
- **Local Area Networking (LAN)** –The network serving end points such as sensors, capacitor banks, homes, etc. - in the same general area as the communications node. Local connections to communications nodes are considered part of the LAN network (ex: a serial connection to a capacitor bank)
- **Node-to-Node Communications (N2N)** –A peer-to-peer form of communications that can be utilized in lieu of, or in conjunction with a WAN connection to a communication node.

The communications node architecture can support multiple wireless and wired communications technologies in order to address unique situational requirements. It's also flexible enough to support very specific applications.





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Conclusion

A cohesive, unified and ubiquitous communication infrastructure is an aggressive goal and many factors play into what solution is the best for each utility. By working together collaboratively, the electric power industry can continue to make significant advances to understand the cost, benefits, challenges and architecture options to prioritize the necessary research that can have the most positive impact on electric grid reliability and affordability.



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About the authors



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Jason Handley, P.E. is Technology Development Manager in the Emerging Technology Office at Duke Energy. Jason has over 18 years of electric utility experience specializing in the smart grid, distribution automation,

and operations management. His research and development role allows Jason to use his years of experience to develop, install, test, and evaluate new technologies for Duke's electrical grid. Jason is responsible for developing and updating the strategic roadmap for power grid devices at Duke Energy.

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Utilities and the Incident Command System

By John Kullmann

To improve emergency response operations, utilities across the United States and Canada are increasingly adopting the Incident Command System (ICS). Given what appears to be the increasing severity of weather, the greater number of incidents that result, and instant visibility into events in a wired world, it is no surprise that ICS is gaining in prominence in the utilities industry. Most importantly, ICS is likely to gain even wider adoption because it is a proven approach to coordinated, cost-effective incident management.

To identify trends, best practices, and challenges of ICS in the utilities industry, Macrosoft, Inc. conducted an online survey during August 2013. It encompassed 85 participants, representing investor-owned as well as municipal utilities, drawn for every region of the U.S. (see Figure 1, with customer bases that range from fewer than 100,000 customers to more than three million.

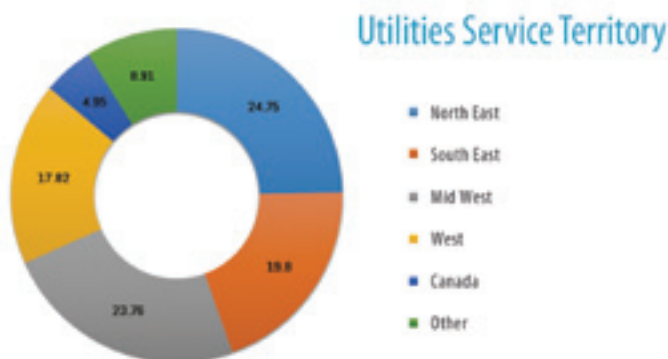


Figure 1

Survey results present a decidedly mixed picture. While much progress has been made, significant obstacles remain. For example, companies are expected to implement ICS but they fail to budget for it, yet this relatively small investment could help them avoid the enormous costs of sub-optimal incident response year after year. Many respondents indicate that during an incident they lack adequate communication with the field or with people they don't normally work with, pointing up the need for systems that provide fast and effective communication both internally and externally. As with communication, many companies appear to need a technology solution to help guide

them through the ICS process. But obstacles can also be opportunities, as the survey results indicate in four critical elements of ICS: adoption, training, execution, and tools and technology.

ICS Adoption

Ninety-five percent of survey respondents see ICS as 'important' or 'very important' for effective emergency response. About half use ICS every time an incident occurs, followed by a little less than 30 percent who report using ICS 'sometimes' when incidents occur, and 20 percent who are not using it but feel they should.

Asked how they currently implement ICS when an incident occurs, almost half (47%) said they follow the National Incident Management System (NIMS) guidelines, the national blueprint for effective and efficient incident management. But they say also that they customize the guidelines for utility company use. Fourteen percent of respondents use some, but not all, of the guidelines, while 25 percent primarily use their own management system, and 14 percent use none of the guidelines.

Although several respondents said that there is little that is unique about utilities that hinders adoption of ICS, far more cited distinctive industry characteristics. Most utilities, for example, are regionally focused, as opposed to entities that are municipally or nationally focused. Further, utilities work by circuit. An outage in one municipality may require work in another community, a dynamic that local governments sometimes do not understand. Utilities can also be extremely hazardous, requiring a difficult balance between 'make safe' and 'restore.' In addition, utilities have obligations to certain regulators, agencies, and investors; and although senior management is responsible for operations, during an incident many agencies suddenly feel that the utilities report to them.

The overwhelming agreement about the importance of ICS could eventually mean a ground swell of support within the utility industry for the adoption of the ICS process and the establishing of appropriate forms and tools. At the very least, such agreement suggests that utilities not currently using ICS should begin investigating how it might benefit them to adopt it.

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ICS and the Utilities

We are in conversation with Ann Steeves, MCP, MBCP, Operations Manager with Portland General Electric (PGE) about the advantages of a utility adopting the Incident Command System (ICS).

EET&D: Can you provide me with the demographics of the utility?

Steeves: PGE's service territory covers urban (Portland Metro) and rural areas in a seven county area. The company serves almost 900,000 customers (residential, business, and industrial/commercial).

EET&D: Are there unique challenges (geography, prevailing weather, etc.) faced in serving your customer base? In that vein, are utilities bound to move up from analog to two-way digital communications systems to ensure more accurate and wider coverage of their service territories when reaching field crews?

Steeves: Oregon is on the Pacific Ring of Fire which hosts a very diverse landscape including the risk of the Cascadia Subduction Zone earthquake/tsunami (predicted to be 9.0 shaking for up to four minutes followed 20 minutes later by a tsunami along our coast); Pacific Storms (they don't call them hurricanes out here) and Winter Storms with snow and ice. PGE is strengthening its current communications capabilities to reach crews in any number of locations.

EET&D: Is ICS mandated in your state?

Steeves: ICS is not mandated in Oregon but strongly encouraged and widely adopted. Some of the best trainers in the country hail from Oregon (those who serve on Type 1 Incident Management Teams (IMTs)).

EET&D: Has there been an incident where the ICS has 'saved your skin' or that of your customers?

Staffs that are trained and use ICS frequently; it is always 'on' and follow a planned, trained process of escalation. If you plan, train and exercise well, ICS becomes one of the tools in your toolkit.

EET&D: Are the implementation and standard features of ICS user-friendly – how easy would it be to sell to a nay-sayer, for example?

Steeves: Initially, ICS is not easily understood and requires a paradigm shift or culture change. Those implementing the system have to first understand the utility, how it responds, and adapt a cadence for ICS implementation that will make it adoptable. Today, ICS as offered at the national/federal level is NOT utility friendly. The Western Energy Institute (WEI) out west is working with all of the interested utilities to take ICS to the next level.

EET&D: Do you have an ICS training program in place?

Steeves: PGE has an ICS training program in place and is focused on three levels:

- Corporate Incident Management Team
- Facility based Incident Management Teams to handle local incidents
- ICS in the Field – PGE Personnel arriving on scene with Law Enforcement or Fire

EET&D: From strictly the T&D side, taking into account individual inherent bureaucratic differences, who in your estimation is more likely to accept and implement the program – where costs, standardization, training, etc. are all taken into account Munis, IOUs, ISOs, Co-ops?

Steeves: Part of this equation is making ICS valuable and affordable. The materials currently available at the national/federal level have not been tailored to utilities. The industry still needs to approach this work in order for utilities to see the benefit of ICS. One other topic of discussion is 'to certify or not to certify' – this is a rather expensive proposition in terms of FEMA seat time requirements – reinventing the wheel would be more costly. The industry will need to decide.

The more utilities gain in terms of ICS the more likely they will be to utilize a system that has been implemented in a variety of other disciplines with demonstration of its value and the more interoperable utilities will become when they have to support one another through mutual assistance in times of need.

EET&D: We can't thank you enough Ann for taking the time out of what must be a crazy schedule to let our readers in on some of the important details surrounding ICS in general and how it fits in with PGE's mandate.



About the author

Ann Steeves is the Operations Manager for Business Continuity Emergency Management (BCEM) at PGE.

The Challenges of Training

From the survey, the challenges of training emerged as a recurrent theme. For example, while the adoption of standard guidelines may be accelerating, the availability of training to the industry appears to be insufficient. The training that the Federal Emergency Management Agency (FEMA) offers remains focused on the community-based first responders – utilities may therefore find it difficult to adopt materials and exercises that are not applicable to utility-response. In addition, some respondents observed that it is difficult to find the time to train an already busy workforce on a second set of responsibilities

How companies train on ICS varies widely:

- 40 percent follow the national guidelines
- 29 percent use in-house, non-FEMA training only
- 23 percent use FEMA online training and in-house training
- 8 percent use FEMA online training only.

As these results indicate, a great deal of in-house, non-FEMA training is currently taking place, but when non-FEMA training is conducted by utilities, industry experts say, it tends to be about 'organizational incident management' rather than ICS.

Frequency of training also varies widely. Fifty percent of companies train on ICS annually, about 10 percent train quarterly, and among those who responded 'other' several say they train monthly. In addition, a few companies train based on employee turnover or whenever there is a corporate mandate to train.

Regular formal training remains a critical success factor for all ICS functions, no matter how the training is conducted. During an incident, procedures must be followed out of deeply ingrained habit – there is no time to open old training guides. Given this imperative, job aids and just-in-time computer-based training can be a great help. Yet utility companies have not yet automated, standardized and made scalable the processes for its use, some of which disparity may be attributable to the lack of materials suitable for the industry.

Execution: ICS in Action

A number of companies indicated that for them ICS is 'always on.' For the other respondents, the trigger points for activating ICS fall into three distinct groups:

1. Size of the incident
2. Number of outages
3. When someone either internally or externally declares that it is time to use it.

Asked which critical success factor is the biggest challenge during an incident, almost 27 percent selected 'comprehensive resource management' (see Figure 2). 'Action planning' and 'manageable span of control' were each cited by 16percent of respondents as the biggest executional challenge of ICS.



Figure 2

ICS specifies that any single person's span of control should be between three and seven individuals. If more than seven resources are being managed by an individual, then that person is being overloaded. To avoid overload, ICS expands the command structure by delegating responsibilities, which can empower otherwise junior employees to make decisions that exceed the authority of their day-to-day jobs. Asked whether junior employees are given greater authority when ICS is activated:

- 56% said 'sometimes,'
- 20% who said 'always,'
- 13% who said 'never'
- 12% who said 'ideally, but not currently'

Further, said some respondents, even though their companies have adopted ICS and train on it personnel often revert to their normal day-to-day way of doing things when an incident occurs.

As the issues of resource management and span of control suggest, ICS is a management system, not merely a communication system, yet 30 percent of respondents say that when their companies activate ICS it is used only for communication. While the 70 percent who said that their companies use ICS as a management system, is an overwhelming majority, it is sobering to reflect that as many as three in ten companies do not leverage the intended purpose of the system.

One of the great advantages of the system is its ability to scale. Eighty-six percent of companies that use ICS expand and contract it according to the nature of the incident. Surprisingly, however, less than 30 percent of companies always begin preparing for demobilization on day one of an incident and 40 percent never do. Huge cost overruns can be incurred if demobilization is not planned

early, resulting, for example, in a parade of bucket trucks all restoring power to the last home. By contrast, effective ICS demobilizes crews once there is a schedule for remedying all disruptions to the system.

Enablers: Tools and Technology

Fifty-six percent of companies have modified 'standard' ICS forms and tools to match their requirements. That's not surprising, since those forms were not designed for electric power companies in the first place, but widespread modification of forms will result in multiple versions of ICS across the industry. However, there are 14 forms that are used either always or sometimes by at least half of utility companies and might provide the starting point for standardization across the industry (see Figure 3).

Please indicate which of the ICS forms (or similar forms) your organization currently uses?				
	Always	Sometimes	Not Needed	Ideally
203, Org. Assignment List	67%	12%	5%	16%
202, Incident Objectives	64%	17%	7%	12%
201, Incident Briefing	56%	26%	2%	16%
204, Assignment List	56%	23%	5%	16%
209, Incident Status Summary	55%	23%	8%	15%
211, Check-In List	48%	25%	10%	18%
213, General Message	46%	22%	15%	17%
215, Operational Planning Worksheet	46%	21%	8%	26%
214, Unit Log	40%	15%	18%	28%
205, Radio Comm. Plan	33%	21%	23%	23%
221, Demobilization Plan	33%	28%	18%	23%
308, Resource Order Form	32%	24%	24%	19%
206, Medical Plan	31%	23%	21%	26%
218, Support Vehicle Inventory	30%	22%	24%	24%
216, Radio Requirement Worksheet	26%	16%	37%	21%
217, Radio Frequency Assignment	26%	16%	34%	24%
210, Status Change Card	26%	20%	34%	20%
219, Crew, Helicopter, Aircraft, Dozer	23%	18%	44%	15%
220, Air Operations Summary	17%	14%	50%	19%
226, Individual Personnel Rating	14%	14%	39%	33%

Figure 3

A large number of survey participants cited automated systems as a key enabler of an improved ICS process. They also identified the critical requirements of such a system: ease-of-use, ample reporting for senior management, ability to communicate with existing systems, real-time situational awareness, and uniformity across multiple utilities. However, as the survey results indicate, automated systems and uniformity across the industry have a long way to go. In fact, almost two-thirds of companies use ICS solutions that are either paper-based or homegrown.

In addition to the 66 percent of respondents who are using a paper-based or homegrown system, a number who responded 'other' identified their systems as a mix of the two. In answer to a related question, 56 percent of respondents indicated that their companies have no software application supporting their ICS process.

ICS and the Utilities

With a different take on the Incident Command System, EET&D is speaking with Joseph (Joe) M. Golden, Jr., EMT-P, CHMM, CEM, CBCP, MEP. Joe is a Critical Infrastructure Protection consultant.

EET&D: Please give us an idea of where your job as consultant has taken you?

Golden: I've worked with utilities in the Northeast, South/Gulf Coast, Texas, and California.

EET&D: Was there any incident in particular that you would consider to be a 'wake-up call'?

Golden: For the Northeast it was definitely hurricanes Irene and Sandy. For the South, I would have to say the horrific April 25–28, 2011 tornado outbreak. The Gulf Coast and Texas when they were hammered by Katrina, Rita, and Ike.

EET&D: Is ICS generally mandated?

Golden: I've worked with utilities in states that required ICS and others that don't.

EET&D: Has there been an incident where the ICS has 'saved your skin' or that of your customers?

Golden: One utility told me that learning and practicing ICS allowed them to 'eat an elephant one bite at a time'... that is, ICS principles (e.g., management by objectives, incident action plan, span of control) allowed them to tackle a comprehensive recovery effort that would have seem overwhelming before.

EET&D: Are the implementation and standard features of ICS user-friendly – how easy would it be to sell to a nay-sayer, for example?

Golden: The key is to customize training on ICS to the utility. Utility management and staff do not see the benefits of ICS while training using wildfire and non-utility disaster scenarios. Once the concepts and principles of ICS are applied to a utility in training, the benefits become clearer and practice does become user friendly.

EET&D: Do you have an ICS training program in place?

Golden: Most of my work with utilities started with creating and implementing their ICS training program.

EET&D: From strictly the T&D side, taking into account individual inherent bureaucratic differences, who in your estimation is more likely to accept and implement the program – where costs, standardization, training, etc. are all taken into account Munis, IOUs, ISOs, Co-ops?

Golden: The issue is culture change – the need to transitioning from a reactive approach to proactive approach. Looking at what you're doing today, planning on what you can do tomorrow with the resources at hand, and implementing the plan tomorrow.

EET&D: Joe, on behalf of the magazine, I would like to thank you for your insights as a consultant in this key area. We appreciate your time from an obviously ubiquitous and hectic schedule.

About the author



Joseph (Joe) M. Golden, Jr., EMT-P, CHMM, CEM, CBCP, MEP has been working with utilities and critical infrastructure for 20 years in improving their preparedness, incident management, and response capabilities.

These results are worrisome in that paper-based tools are slow and lack search and reporting capability while home-grown tools lack consistency across the industry and are subject to neglect.

Companies also use a wide variety of means to deliver information to the field (see Figure 4). While 37 percent of companies deliver information to the field via email or mobile data terminals, 27 percent do so verbally or via paper. Further, those who responded 'other' indicated that they use wide variety of combined communication methods, which may include email, text, cell phone, verbal, and paper. While the use of multiple methods is understandable, the question arises as to whether these combinations of methods are used in a consistent fashion or are merely ad hoc, allowing personnel to use whatever is convenient rather than what is best for the situation and the company.

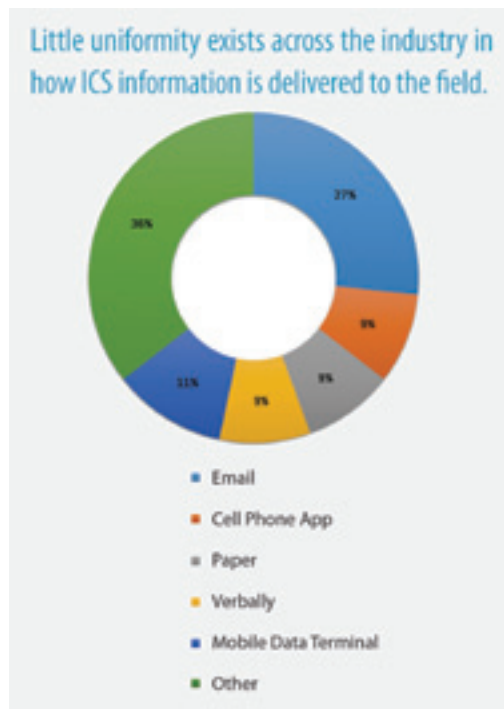


Figure 4

The Way Forward?

The adoption and implementation of ICS, as with any comprehensive system intended to manage highly complex phenomena, will inevitably encounter obstacles. But those shortcomings – the lack of uniformity, standardization, and automation in ICS adoption, training, execution, and tools – also suggest some concrete steps the industry could take to overcome them.

For example, companies could begin by sharing the ways in which they have modified and customized the most widely used ICS forms. They could then identify best practices and create industry-wide standard forms – preferably 'smart' forms that can be passed from shift to shift on a common platform. A widely adopted software application or automated guide to ICS could also significantly help provide a higher level of uniformity, efficiency, and effectiveness than ad hoc and homegrown approaches. The emergence of an automated, industry-wide system could be facilitated by the creation of a standards-body to ensure to ensure uniformity. In addition, utility companies may want to consider further combining their efforts in a development and training institute that might be something like FEMA's Emergency Management Institute. In any case, industry experts observe that the more standardization and commonalities both within the industry and across entities that interface then the more effective ICS will be, benefitting everyone: customers, companies, and the communities they serve.

ABOUT THE AUTHOR



John Kullmann is Vice President of Marketing and Sales at Macrosoft, a New Jersey Technology company. With more than twenty years experience, John is a recognized expert in business development efforts for professional services firms. He is responsible for expanding Macrosoft from its traditional roots as a leading software development and system implementation company into an equally accomplished provider of packaged technology products.

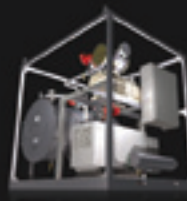


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Wireless Field Area Networks

Key Foundation for Smart Grid Applications

By Bert Williams

Increasingly, utilities are deploying intelligent electronic devices (IEDs) and other smart apparatus in substations and along distribution feeders as well as equipping field workers with laptop, tablet and handheld computers. These technologies are often labeled smart grid. They enable valuable applications such as automated metering infrastructure (AMI), substation automation, distribution automation, outage management, automatic load shedding, and the ability to manage alternative energy sources.

Two way smart grid communication links the people and devices in the field with software at substations and the utility's operations center, enabling applications that deliver vast improvements in efficiency, security, reliability and resiliency. Extending communication from the substation control house to the substation yard and along distribution feeders is best accomplished using wireless field area communication networks. This article discusses the requirement for a utility wireless field area network and describes how a wireless mesh network architecture can meet these requirements.

Typical Utility Communication Network Architecture

Utilities typically implement a multi-tier communication network architecture described as follows and illustrated in Figure 1, below:

- Tier 1: The utility's core IP network, shown in yellow in Figure 1. It is generally implemented using fiber and point-to-point (PTP) wireless. In the example of a utility, the core IP network often connects many of the distribution substations. The demarcation point between the Tier 1 network and Tier 2 network is generally a port on a VLAN-capable Ethernet switch. The Tier 1 network connects to the Tier 2 Field Area Network (FAN).
- Tier 2: The FAN, shown by the dashed blue lines in Figure 1. This tier uses wireless technology, usually broadband wireless mesh, point-to-multipoint (PTMP), and/or cellular data. Substation automation devices (e.g., breaker controllers, voltage regulators, and remote terminal units (RTUs)), distribution automation devices (e.g., capacitor bank controllers, recloser controllers, and smart transformers), AMI collectors, and mobile workers equipped with laptops, tablets or handhelds connect to the FAN. FAN connections can be wireless or wired Ethernet or serial links.
- Tier 3: The Neighborhood Area Network (NAN) or advanced metering infrastructure (AMI) network, including smart meters and collectors. This tier is illustrated by the dashed grey lines in Figure 1. It is generally implemented using narrowband wireless mesh or cellular data. When a broadband wireless mesh network is used to implement the Tier 2 network, the AMI collectors in the Tier 3 networks are generally co-located with the mesh routers that form the Tier 2 network. The collectors attach to a wired Ethernet port on the mesh routers.

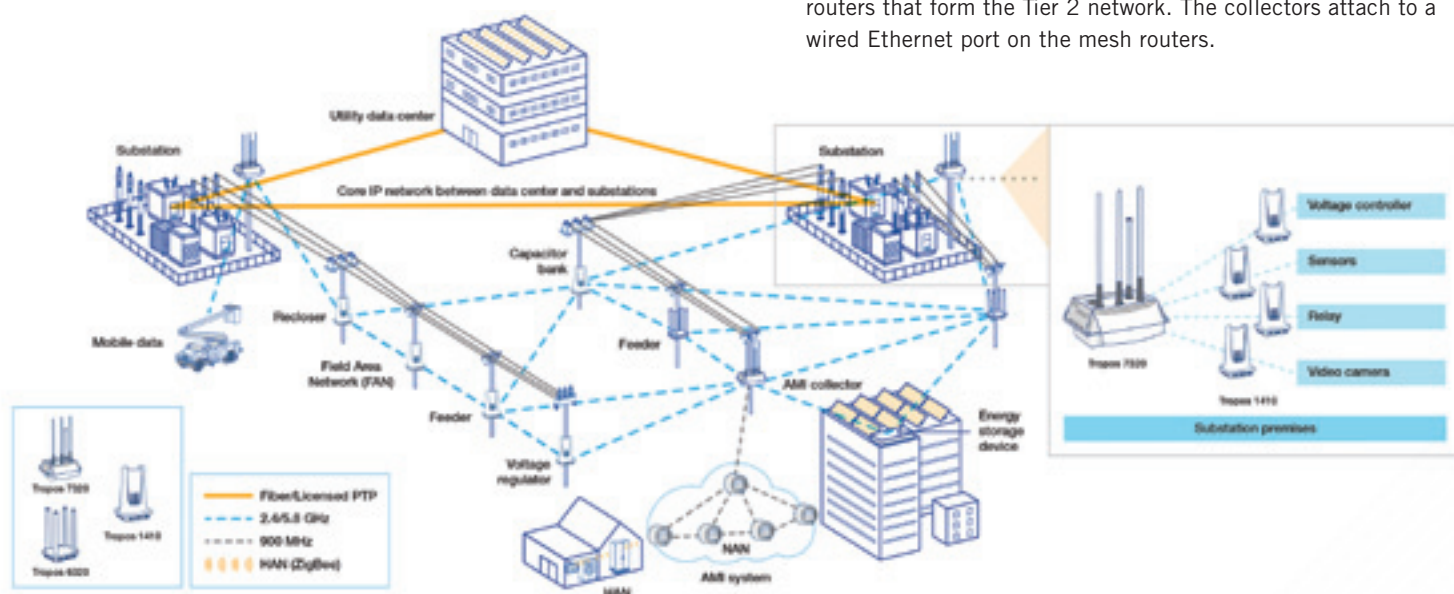


Figure 1: Typical Utility Communication Network Architecture

Wireless Field Area Networks

Key Foundation for Smart Grid Applications

- Tier 4: The Home Area Network (HAN). HANs are implemented using ZigBee or HomePlug technology. They network smart appliances and in-home displays, connecting to the NAN via a smart meter. The HAN is shown inside the house in the lower middle portion of Figure 1.

Note: The remainder of this article focuses on the Tier 2 FAN.

Field Area Network Requirements

FANs fill the communication gap between the core Tier 1 networks and devices, as well as personnel, in the field. FANs are most often implemented with wireless networking technologies because their large geographic coverage areas, large number of connected devices and the need to support mobile field workers make it technically and economically infeasible to implement them using wired technologies. Wireless networking technologies used in FANs include cellular, narrowband point-to-multipoint (PTMP), broadband PTMP and broadband wireless mesh networks.

To support many applications concurrently, FANs must meet the superset requirements of all current and future smart grid applications.

High Reliability

Communications are most critical during outages. FANs must operate even when events disable the electric grid. Ideally, the wireless network will incorporate cognitive radio software that can, for instance, automatically route around interference, failures and congestion. Individual communication devices must be ruggedized, weatherized, and supply battery backup.

Scalable

Field area communication networks must scale to cover large geographic areas, potentially the utility's entire service territory. They must also scale to support, directly or via NANs, millions of connected devices. At the same time, because utilities may choose to roll out their smart grids incrementally, the FAN must be economical to implement on a small scale, say at a single substation or along a single distribution feeder.

High Performance

Traditionally, utility applications sent and received little data. Consequently, utilities generally installed low capacity networks.

As IEDs and other intelligent field devices proliferate, become smarter and gather more information, capacity needs are changing. High capacity networks are required because more applications and devices use the FAN and they send and receive more data.

Additional capacity is also required to support mobile workforce applications.

Many applications in the distribution system are not latency sensitive. However, the few that are, including protection and safety applications, are critical. Because a unified FAN must support the requirements of all deployed applications, low latency is essential.

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Wireless Field Area Networks

Key Foundation for Smart Grid Applications

Because of these factors, utility FANs must deliver sufficient capacity to support all current and future smart grid applications simultaneously and provide latency that is low enough to support the most delay sensitive application.

Secure

Like all networks, wireless field area networks come with potential vulnerability to cyber-attacks. In IP-based FANs, this challenge can be met by implementing a multi-layer, defense-in-depth security architecture using enterprise tools and techniques.

Mobility

Providing communications for field crews requires that the FAN support mobility.

Multi-Application

It may seem a tautology that a network that can support many applications must offer multi-application support. However, supporting multiple applications on a network drives some specific technical requirements such as the need to provide virtual local area networks (VLANs) and and quality of service (QoS). For example, while low latency is essential, it doesn't help if traffic for safety and protection applications is stuck in a queue behind less important traffic, e.g., AMI interval reads. Therefore, application prioritization is required to ensure that delay-sensitive traffic gets to its destination in time.

Flexible

To support the widest variety of applications and devices, the FAN must be built on industry standards such as TCP/UDP/IP, 802.11 (Wi-Fi) and 802.3 (Ethernet). To best integrate legacy field devices and avoid stranded assets, the FAN must also support secure network connections to devices that use serial links and automation protocols.

Field Area Communication Network Technology Choices

As shown in Figure 2, numerous wireless technology choices exist for implementing FANs. However, when the characteristics of these technologies are compared to FAN requirements, broadband wireless mesh networks, supplemented by PTMP links when needed, best meet the requirements.

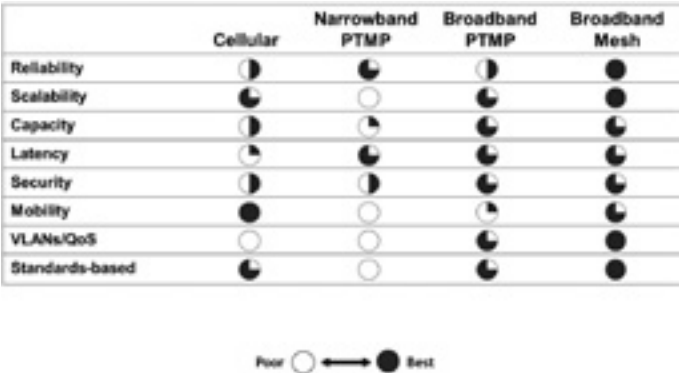


Figure 2: Wireless FAN Technology Choices

Broadband wireless mesh networks offer the following characteristics:

Highly available: Wireless mesh networks provide high availability by automatically selecting the best route through the network from multiple radio frequency (RF) paths, channels and bands. To withstand extremes in climate, mesh routers with extended operating temperature ranges, enhanced wind survivability and housings fabricated using specialized alloys and plating are available.

Scalable: Broadband wireless mesh networks have been proven to scale to large coverage areas (3,000 square miles in Abu Dhabi), large number of users transferring massive volumes of data (19,000 users transferring nearly 600 GB of data daily in Google's Mountain View, California network, 1 TB of data transferred daily in Ponca City, Oklahoma), large numbers of M2M end-points (more than 1 million electricity and water meters in Abu Dhabi) and large numbers of routers (more than 3,000 routers operating in the network in Abu Dhabi). However, because mesh networks generally don't require tower construction, they can also economically cover small areas, such as a single distribution feeder.

High capacity and low latency: Broadband wireless mesh networks can provide >10 Mbps of throughput at each mesh router with latency of <1 ms per mesh hop.

Secure: Broadband wireless mesh networks can implement a multi-layer, defense-in-depth security architecture using open security standards. Open standard, enterprise security tools and techniques have been honed for years and are constantly being updated. As a result, utilities can leverage the past and ongoing work of the enterprise and internet security community. Using a multi-layer, defense-in-depth approach with standards based tools wireless mesh networks have attained FIPS 140-2 compliance and are compatible with NERC CIP v5, NISTIR 7628 and IEC 6235.

Mobility: Broadband wireless mesh networks provide seamless, session-persistent roaming at vehicular speeds for as long as they stay within the mesh coverage area. Clients, including those that have established an IPsec/VPN connection, can move between nodes, gateway and even IP subnets without losing connections. The best mobile network connections can be achieved by using a mobile mesh router.

VLANs/Application QoS: Broadband wireless mesh networks support VLANs and QoS. VLANs enable traffic from different applications and user groups to be segregated. They permit security and QoS policies to be tailored to the needs of each application/user group. QoS capability ensures that traffic for latency-sensitive mission-critical applications are prioritized relative to latency-insensitive communications such as metering data.

Wireless Field Area Networks

Key Foundation for Smart Grid Applications

Flexibility/Interoperability/Open Standards: Broadband wireless mesh networks support open standards so that they can interoperate with other standards-based smart grid components. Standards supported by wireless mesh networks include TCP/UDP/IP, 802.11 (Wi-Fi) and 802.3 (Ethernet). To integrate legacy field devices and avoid stranded assets, some mesh routers also support secure network connections to devices that use serial RS-232 or RS-485 links and automation protocols such as DNP-3 and IEC 61850.

Implementing Field Area Communication Networks Using Broadband Wireless Mesh

Broadband wireless mesh networks are implemented by installing mesh routers throughout the coverage area. Along a feeder, units typically mount on the horizontal mast arm of a street light pole or to a power pole and are typically AC powered. To provide wireless communication across a substation floor, mesh routers can be mounted to structures and equipment within the substation. Mobile mesh routers can be installed in vehicles.

Some mesh routers, called gateways, connect to the Tier 1 core IP network. In areas where gateways are required but a fiber drop to the Tier 1 network is not readily available, PTMP wireless links can fill the void. The percentage of mesh routers configured as gateways varies depending on the amount of traffic that needs to travel to/from the Tier 1 network and the FAN.

Mesh routers not configured as gateways communicate entirely via wireless. Upon installation, mesh routers automatically discover one another and self-organize into an interconnected wireless mesh network. Each mesh router determines the presence of both clients and other mesh routers. Once a mesh router has identified the existence of other like devices, it builds a table of neighboring devices and the corresponding paths through the network that each neighbor provides. The mesh router then identifies the optimal path to send data across the network, to the wired gateway.

Not All Mesh Networks Are Created Equal

Unfortunately, in the utility industry, the term mesh network has created some confusion because two different types of mesh networks are used for two different applications.

Utilities tend to be more familiar with the AMI meter meshes used to implement the NANs that transport metering data between meters and their associated AMI collectors. These narrowband mesh networks use lower frequency bands, supply much less capacity and cover smaller geographic areas with fewer connected devices than the broadband mesh networks that are the subject of this article.

Broadband wireless mesh networks use higher frequencies, typically the 2.4 GHz and 5 GHz RF bands. These frequency bands supply more and wider RF channels, providing higher capacity and the option to automatically move between channels within a band and between bands to mitigate interference. Broadband mesh networks have been proven to scale to very high capacity (1 TB per day), large coverage areas (3,000 square miles) and large numbers of connected devices (1 million).

Conclusion

Communication networks are a key component to smart grid implementation. Utilities implementing smart grid communication networks generally use a multi-tier network architecture. A number of wireless technology choices are available to Tier 2 network – the field area network or FAN. When comparing the capabilities of these technology choices to the requirements of the FAN, broadband wireless mesh networks, supplemented by PTMP links when necessary, provide the best match to the requirements.



About the author

Bert Williams is the Director, Global Marketing for ABB Tropos Wireless Communication Systems and brings 30 years of experience in successfully leading the marketing organizations of networking companies. Mr. Williams was Vice President of Marketing for Tropos Networks from 2002 to 2007 and returned to the company shortly before its acquisition by ABB after working as an executive marketing consultant for four years. Prior to Tropos, Bert held senior marketing positions at Alteon WebSystems (acquired by Nortel Networks), Qualix Group, SynOptics Communications (part of Bay Networks), Synernetics and Advanced Micro Devices. He holds a BS with University Honors in Electrical Engineering from Carnegie Mellon and an MBA from Harvard Business School.

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Smart Grid Laboratory

Research, Innovation, Testing, and Education

By Dr. Bala Venkatesh, PE

Introduction

Ryerson University founded the Centre for Urban Energy (CUE) in September 2010 along with founding sponsors, Hydro One, Ontario Power Authority (OPA), and Toronto Hydro. Ryerson University has invested about \$1.5 million towards the Centre's infrastructure and devoted significant manpower towards its development and operations. Founding sponsors Hydro One, Ontario Power Authority and Toronto Hydro have invested around \$7 million towards research projects, research fellowships and student awards. These sponsors further contribute to the success of the centre through countless hours of manpower by participating in research projects and other activities at the Centre.

Since its inception, the Centre for Urban Energy has initiated 18 large projects on topics such as smart grids, energy storage, transmission and distribution system analysis renewable energy, . A few projects have been completed such as the design of controller for Temporal Power's flywheel, energy storage system. Currently, is pursuing a flagship project on energy storage in batteries worth \$8 million in collaboration with Natural Resources Canada, Hydro One, Toronto Hydro, OPA, Ontario Centres of Excellence, Electrovaya, Manitoba HVDC, Manitoba Hydro, and Tennessee Valley Authority.

The facility also operates an incubator for encouraging innovators from Ryerson and all other Ontarians to bring new productize-able ideas for research and commercialization. CUE has several projects where it collaborates and partners with other also Ontario universities such as Western University, University of Waterloo, University of Ontario Institute of Technology, York University and University of Toronto.

The vision of this centre is to be a world class research and innovation centre dedicated to solving urban energy challenges. In addition to Research and Development, CUE shall pioneer in large utility scale demonstration projects that shall facilitate innovation and commercialization of groundbreaking energy solutions of the future.

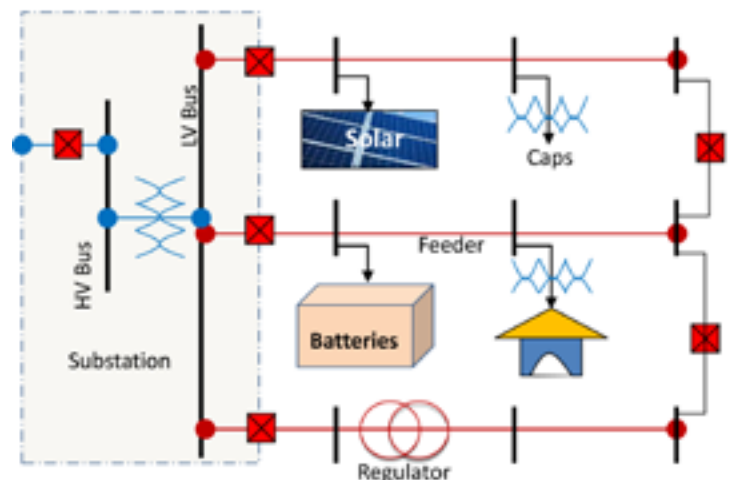
Schneider Electric Smart Grid Lab

Now that the Centre for Urban Energy has been operating for three years, it is looking to expand its operations by building a smart grid laboratory with several characteristics: research, innovation, testing and education. The lab has been made possible by the generous funding from Schneider Electric and the Ontario Ministry of Energy.

Purpose of the Laboratory

The laboratory shall be a multifunctional laboratory mimicking – in a reduced scale – an automated distribution system at 3-phase 600 V. The essential components of this laboratory shall include:

- Solar panels with inverters (controlled)
- Energy storage (batteries) with controlled bi-directional converters
- Controlled AC Loads with AC-DC-AC back-to-back converters
- Controlled DC Loads with rectifiers
- Circuit breakers with IEC 61850 interface
- Transformers
- Relay equipment including ECTs and EVT
- Hardware for IEC 61850 ring.
- A Distribution Management System (DMS) including hardware and software



At Ryerson University, we will study, develop and implement the following smart grid projects:

1. Supervisory Control

The network, as shown in Figure 1, can be isolated by opening circuit breaker CB1. On achieving generation and load balance, the system can be operated as a microgrid. The purpose of such research work is to implement, test and demonstrate converters and inverters that can be used for frequency control of an islanded system. Furthermore, this shall enable demonstration of supervisory control and protection of the microgrid.

2. Harmonics Study

Of concern to utilities, is the impact of harmonics on assets such as transformers and capacitors. This laboratory shall try to study, measure, quantify, and understand the impact of harmonics from sources with power electronics on transformers. As can be seen, the laboratory architecture lends to this type of investigation. Studies shall be undertaken to quantify harmonic effects, at various levels of generation by these sources, on assets such as transformers. Parameters such as total harmonic distortion shall be studied. Their cumulative effect of these generation sources on assets shall be studied as well.

3. Optimize 24-Hour Energy Consumption

For large customers such as high rise condominiums, hospitals, universities, hotels and other dense energy users, energy bills and reliability of supply is a concern. They all own, operate and maintain backup diesel generators. As can be seen, the DS architecture is comparable to such large users. An aim of this laboratory is to develop and implement a 24-hour scheduling system such that energy bills are minimized (by energy arbitrage) and reliability is maximized for overcoming any supply failure through energy storage.

4. Microgrid Operation

In future, microgrids shall be a commonplace in large customer sites – with comparable AC and DC Networks. This laboratory shall establish a microgrid when circuit breaker CB1 opens. Near term load forecasting, short term load forecasting, load management, operation improvement, energy storage optimization – and DG management are also the essential functions for microgrid operation.

5. Protection and Coordination

Protection and control methods for microgrids are a topic for future study. This laboratory shall undertake research in this direction to develop appropriate protection schemes and relaying techniques. Further, the laboratory shall have switchgear that enables fault isolation and restoration.

These futuristic switchgear solutions require appropriate developments in protection and relaying equipment. Research and innovation efforts in this laboratory shall focus in that direction.

6. Advanced Metering Infrastructure (AMI)

A portion of the smart grid laboratory will become an advanced metering infrastructure (AMI) test facility. It will allow new metering products and innovations to be plugged in and tested ahead of industrial scale pilots. The laboratory shall be a neutral site engaging in non-revenue type feature testing.

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In addition, efforts are being undertaken to explore the possibility of using advanced metering infrastructure to enable local energy commerce, improve system reliability, provide improved distribution system performance. Research, innovation and demonstration efforts in this laboratory shall focus on creating next generation solutions using advanced metering infrastructure in tandem with advanced distribution management systems.

7. Pilot Testing

The Centre for Urban Energy is big on pilot testing of new and innovative products. It provides a neutral testing opportunity for products of interest for utilities and energy innovators. Examples are the ElectroVaya battery testing, Temporal Power flywheel, IceBear thermal energy storage (sponsored by Toronto Hydro). The proposed laboratory will help in testing smart grid ideas on a utility scale demo right here in Ryerson's downtown campus. It will provide easy physical access and remote access internet. This collaborative space shall provide a unique opportunity Ontario institutions for the testing and demonstration of smart grid products.

8. Conservation and Demand Management

Conservation and demand management technologies and solutions are being championed in Ontario. These solutions enable demand-supply balance by avoiding new generation through either conservation programs or demand response tools. Conservation programs reduce net energy consumption. The other tool is demand management where peak demand is reduced during peak hours thereby reducing clearing prices. Which has a profound effect. In the province of Ontario, these programs are rolled out via distribution companies. This laboratory will enable development of new conservation and demand management solutions.

Which can also be pilot tested and validated in the same space.

9. Other Research and Innovation

Several smart grid projects are underway at Ryerson University's Centre for Urban Energy, the University of Waterloo Institute of Sustainable Energy, Western University and other institutions in Ontario such as the Clean Energy Institute. These include algorithms and products for analysis, control, and optimization of smart grid elements such as advanced distribution systems and microgrids. These research and innovation products need a venue for pilot testing and demonstration. This laboratory shall provide an industrial test bed for such pilot testing and demonstrations for developers, investors and other international participants who might wish to engage and benefit.

10. Education

The Centre for Urban Energy hosts 10 student projects on smart grids from the Department of Electrical and Computer Engineering each year. They are funded through generous grants from Hydro One and Toronto Hydro. These students will directly benefit by being trained in this state-of-the-art facility. Ryerson University has also announced plans for graduate programs in Energy and Innovation. Students in these graduate programs shall have a four-month internship in this smart grid laboratory as a part of their curriculum. Creation of this laboratory shall directly facilitate training of highly qualified personnel specializing in smart grids contributing to provincial economy.

About the author



Dr. Bala Venkatesh is both founding Academic Director and head of the Ryerson Centre for Urban Energy (CUE). He currently serves

as a Professor of Electrical Engineering at Ryerson and has also taught at the University of New Brunswick, Multimedia University (Malaysia), and Anna University (India). He has published more than 100 articles in journals and conferences and has supervised 34 MSc and PhD theses. In total, his extramural funding is more than 10 million dollars. He is a registered professional engineer in Ontario and, in the last two decades, has worked on over 10 consulting projects in India and Canada.

Everything that could possibly go wrong in AMI rollouts already has ... and we've learned from it

New mobile workflow optimization approaches are rewriting smart meter deployment best practices

By Shashi Gupta

Problems associated with poor installations of advanced meters have done tremendous damage to public perceptions about the utility industry. To those familiar with the challenges associated with advanced metering infrastructure (AMI) deployments, it comes as no surprise that significant quality and process issues, such as hot meter sockets and other safety and reliability problems, have come to the fore. AMI can present customer-facing issues too, including customer billing errors from improperly registered meters and poor handling of utility customers by an inexperienced, hybrid workforce. Lost meters and poor inventory tracking, schedule overruns and inefficiencies in a range of processes can drive up project costs.

Utility executives are demanding new processes, tools and strategies to confront these risks. To withstand regulatory and media scrutiny, AMI rollouts require fail-safe programs and processes that ensure automated process compliance and tracking. Utility executives know that when it comes to batch errors, hot sockets, and billing mix ups that "one such incident can stall the whole project." In an environment where every public mistake is magnified, best practices are beginning to emerge, and workflow optimization systems are playing a pivotal role in ensuring adherence to standards and structures providing documentable audit trails.

What Can Go Wrong? – Identifying AMI Deployment Risks

System-wide advanced metering infrastructure (AMI) deployments represent an unusually substantial resource commitment for a utility. A highly varied workforce that includes relatively inexperienced field personnel often carries out AMI rollouts. Problem areas generally relate to installation processes and personnel, rather than being specific to a particular meter manufacturer. AMI deployment problems include:

1. Hot meter sockets and associated fire hazards
2. Meter registration, batching, and pairing installation errors
3. Meter inventory errors (lost meters and/or inefficient tracking)
4. Inefficient processes (for workers, managers and/or administrators)
5. Safety, reliability, or customer-facing process deficiencies
6. Liabilities arising from a lack of audit/photo trail of standards-based activities

The New AMI Best Practices

Early smart meter deployments yielded some hard lessons, and that knowledge has become the basis for metering specific approaches that draw on business process management approaches, particularly mobile

workflow optimization. Utilities today can apply these practices to avoid pitfalls and ensure success.

No.1 – Think Processes, not Features

To find the right approach, utility managers accustomed to evaluating software solutions on features and functionality will need to look at workflow optimization solutions in a holistic, process-centric way rather than in a fragmented 'module centric' fashion. Doing so will reveal the powerful common business process management principles as the source of dramatic improvements across different workflow scenarios. What are your productivity objectives? Workflow optimization can address a variety of challenges in AMI deployments, including:

- Ensuring proper work assignments are given and that new team members are assigned work based on their skill set as soon as they are badged
- Allowing the rapid update of assignable tasks after completion of new training.
- Managing the life cycle of a project's inventory
- Integrating bar-coding and GPS data into process steps (e.g. tracking meter movements from a pallet being opened, to boxes being moved, to individual meters being installed, with workers scanning their badges so status and location of each meter is traced)
- Guiding workers through each step in various workflows, using interactive questions or prompts, from the moment the meter is removed from the box
- Providing a single system rather than multi-system integration for time sheet and payroll system data tracking

In the early days of AMI deployment, there were no mobile workflow optimization solutions built specifically for this purpose. Those who recognized the role that business process management (BPM) could play had only generic tools that needed to be adapted on an ad hoc basis. Today's solutions incorporate the lessons of the past, building workflows that address the needs and challenges of AMI deployments. Whereas legacy enterprise software solutions often lack native ability to process photographic records, perform job assignment changes based on new certifications, or integrate time sheet and payroll system data, new AMI solutions achieve lasting productivity gains because they are infused with hard won knowledge and purpose built to avoid systemic inefficiencies, process bottlenecks, and common errors.

Mobile workflow optimization has taken long-standing principles of BPM out of factory and IT-centric environments and applied them in new ways for utility-related fieldwork. In addition to choosing an AMI-specific tool, a utility must take a great deal of care to collaborate with the solution provider in designing an optimized workflow for each step in the installation process. An IOU executive reflected on the impact this made in their deployment, "The upfront planning we did with the vendor is really paying dividends. The solution is a real-time system. I can look at the system right now and I can tell you how many meters are currently installed and I have a report that can tell you how many have been installed today."

No. 2 – Deploy 'Forced March' and 'Fault-Resistant' Workflows

Humans are fallible, yet the best workflows do not over – or under – automate a workflow. Optimal approaches find the perfect balance in the interaction of human and automated systems. 'Forced march' workflows help design out errors by rigorous identification of common errors in specific workflows and redesigning tasks that guide the user through the new process step by step. For example, a water utility had a problem with the work process of using a clip to connect a radio to a meter. Installation technicians found it difficult to determine whether the clip was fully inserted. The connector clip has two holes in it, which fully protrude only when the clip is firmly inserted and the radio is connected correctly. To ensure proper connection, a step was added to the workflow requiring the installer to insert toothpicks into the two holes, and then photograph them. The photograph not only provides evidentiary proof that the clip was installed correctly, but also serves as a verification record that gets stored for quality assurance record keeping. Steps in many of the other workflow processes similarly force the correct process to be accomplished and documented, thereby forming key elements of the forced march, which help to eliminate failures.

Similarly, fault-resistant workflow designs prevent workers from engaging in error-prone work processes. This is accomplished by analyzing the "fault trees" of a process and designing against them. One common problem in mass meter deployments is "batching." This occurs when -- instead of removing and replacing one meter at a time -- installers remove many meters at once. Often, when they go to put in the new meters, it becomes impossible to associate the correct old meter with the new meter. Consequently, bills go to the wrong customers, creating a serious public relations issue. Batching can be eliminated by requiring the technician to follow this 3-step process:

1. Take a photo of each meter prior to removal and installation
2. Log the legacy meter number into the system
3. Scan the new meter serial barcode

The workflow mandates that the steps be performed in strict sequence, forcing the technician to install each meter one at a time, and eliminating any possibility of a mix-up.

No. 3 – Collaborate with Experts to Hone Your Tools

An expert who understands both AMI challenges and workflow optimization can tailor your tools for a variety of purposes. Take on expert advice to learn about the tools that address the needs of a specific deployment. Here are a few to consider:

- Photographs of installations can provide valuable opportunities to document customer equipment issues and proactively engage customers for corrective steps while warning them of any hazardous conditions.
- Barcoding can play an important role, too. As parts move through the field, at each change in custody – from the warehouse manager to the installer or between installers in the field – equipment barcodes and worker badges allow managers in the office to identify precisely who has custody of each meter.
- Statistical sampling can identify 'error-prone' situations and single those out for analysis. For example, because newly trained workers, or workers thrown into unfamiliar situations, are among the most error-prone, the sampling process can focus on them. While the overall worker sampling would normally be 7 percent or lower, the sampling for a new worker involved in meter replacements can be set, in the first days, to 100 percent. The best sampling is a real-time shadowing that involves recording observations. As the worker gains experience, the sampling tails off until it reaches the average for all employees.
- Time-stamped GPS data can create an audit trail to track worker progress and improve worker productivity and accuracy.
- Other techniques can address cascading inventory issues by showing, for example, precisely when a pallet has been opened and exactly which units are on the pallet. Such tightly controlled asset management drastically reduces the likelihood of any meter being lost.

No. 4 – Build Positive Customer Engagement into the Process

Early AMI deployments encountered unexpected challenges in consumer engagement. Today's best practices recognize this and proactively incorporate outreach to keep customers informed and satisfied. Mobile workflow optimization guides important customer-facing activities during AMI deployment. An investor-owned utility manager said, "The solution is very process oriented. It is a series of built-in checks. Did you knock on the door? Did you leave a door hanger? So before you can go on to the next process, you have to complete the previous process, do the steps, and answer the questions. The technician cannot change the order of operations or skip steps." The workflow optimization solution ensures that utility communications processes are followed as planned.

Everything that could possibly go wrong in AMI rollouts already has ... and we've learned from it

Utilities deploying AMI today must confront a range of misperceptions and consumer fears around fires, RF exposure, high bills, and more. Mobile workflow optimization solutions address these stakeholder concerns through carefully documented deployment records, workflows and photographic audit trails that greatly reduce the risks associated with the rare occurrence of 'hot sockets.' One utility reported using its mobile workflow optimization solution to take photographic thermal readings of empty meter sockets during installation to ensure a site-specific audit trail of socket conditions. Through a variety of methods, mobile workflow optimization solutions reduce utility liability risks and the risks posed by potentially negative public relations exposure during AMI rollouts. Photos that show on-site conditions before and after work can go a long way to protect a utility from legal liabilities. One utility executive noted, "We have had some situations where the meter reading may be entered incorrectly. Our contractor performed a 'blind validation' of every meter reading captured in the field, using the photo of the legacy meter face, zooming in to read the digital display or the analog dials. This gave us 100 percent accurate meter readings and the photo evidence to back them up. So, if a customer contested their billing, we could verify the accuracy of the reading in our system right in the office, instead of going to the expense of another truck roll to actually look at the meter again."

A Promising Body of Knowledge

The lessons learned by early AMI rollouts have yielded detailed knowledge, which is now available in industry specific workflow optimization solutions. These are yielding successful AMI rollouts that avoid many of the most widely reported deployment pitfalls. In the process, these utilities have lowered risk, increased field productivity, and enhanced consumer engagement. Looking ahead, mobile workflow solutions hold potential to optimize other utility applications including rollouts of load management, home area networks, distributed generation, and

T&D inspections. Forward-looking utility executives who have applied mobile workflow optimization solutions to AMI rollouts have laid a strong foundation to confront unknown challenges and exploit coming opportunities in the distributed energy future.

About the author



Shashi Gupta is an expert in mobile technology that offers the safest, most efficient, least-cost solutions for managing field workforces – by balancing the processing power of computers with the cognitive power of human minds. He is CEO of Apex CoVantage.



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Inside California's Aggressive Energy Storage Mandate

By Mark MacCracken

As we all know (as much as we may hate to admit) California has often been ahead of the times. It is the state that gave birth to the personal computer, punk rock, and martinis after all.

California has also often been the first to push new innovations in energy technology, like solar and wind. So it is no surprise that in October 2013 California became the first state to pass legislation with aggressive energy storage targets: 1,325 megawatts (MW) by 2020.

According to the California Public Utilities Commission (CPUC),¹ the reasons for the energy storage mandate:

1. Increase energy storage at the grid level will optimize the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments
2. Integrate renewable energy
3. Reduction of greenhouse gas emissions to 80 percent below 1990 levels by 2050, per California's goals.

Basically, the goal is to make it more efficient and environmentally friendly for California's big three investor-owned utilities to meet their energy demands. For instance, if you think about a gas plant that is 100 MW in size with a minimum capacity of 50 MW, it can only vary in energy output from 50 to 100 MW. If you take that same plant and use an energy storage solution, the 100 MW plant can now discharge at 100MW but also absorb at 100 MW, so it now has a range of 200 MW – effectively doubling its power potential.

What is the Mandate?

The energy storage target of 1,325 megawatts of energy storage by 2020, including renewable energy generated from solar and wind, is a product of Commissioner Carla Peterman's groundbreaking proposal that was approved by the CPUC. The targeted amount is approximately the amount of energy used by one million homes in a year. Utilities must begin quickly, with a mandate to buy a combined 200 MW of energy storage technology by the end of 2014.

The utilities impacted by the mandate are Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric.

The mandate is technology neutral, meaning the utilities can choose from a wide variety of energy storage technologies and approaches available. However, there are still certain logistics and processes that need to be developed. The installation of energy storage solutions

comes with the caveat that projects need to be reasonable in cost. In the short term, this will be determined by evaluation software tools, but eventually a protocol will be used for benchmarking and general reporting purposes. But this still leaves the questions of what is considered 'cost-effective?'

The Big Picture: Renewable Energy

There is a tremendous need and push for the integration of renewable energy into our power grid as we attempt to phase out fossil fuels like coal and oil. Evidence of this push can be seen in the California Renewables Portfolio Standard. This program, the most ambitious of its kind, requires investor-owned utilities, electric service providers, and community choice aggregators to procure 33 percent of total energy from renewable sources by 2020.² Despite this goal already being aggressive in nature, there are many legislatures pushing to increase that target.

However, the fossil fuels we are replacing with renewables are not just forms of energy, they are forms of stored energy. Renewables like wind or solar are pure energy and considered variable generation sources. They are intermittent in nature and hard to predict because they lack the energy storage aspect of fossil fuels. The inability for renewables to match demand with the fluctuating supply can reduce the stability of the grid. Every utility ultimately wants to smooth peak demand and have a good load factor in order to supply electricity as efficiently as possible. In order to replace fossil fuels, it is time to start thinking about how to add storage capabilities to renewable sources.

Integrating energy storage into the grid is the only way to make renewables a viable, sole energy source, mitigating intermittency of solar, wind and other sources. It also solves many other problems along the energy supply chain: T&D deferral, demand response, power quality & reliability, and frequency control.

So what are California (and other) utility companies thinking about today?

Utility companies have a big learning curve when it comes to energy storage, and some big investments in pilot programs ahead. Here are the three areas that are likely on the top of their minds.

1. **Power quality:** Typically utilities must maintain their power to a frequency of 60 Hz in the US. With current systems, utilities experience energy loss as demand for energy oscillates above and below this frequency. Energy storage can help utilities smooth frequency to meet the 60 Hz cycle at all times.

Inside California's Aggressive Energy Storage Mandate

For example, flywheel systems use a kinetic, or mechanical battery, spinning at very high speeds to store energy that is instantly available when needed. It works by accelerating a cylindrical assembly called a rotor to a very high speed and maintaining, or storing, the energy in the system as rotational energy. The energy is converted back by slowing down the flywheel.

Another example is advanced battery technology, which is able to store a large amount of energy for longer lengths of time, and is often used for power-critical grid applications.

Finally, super capacitors have the ability to store energy and recharge in seconds. Often used in electric cars, super capacitors are typically composed of highly porous carbon that is impregnated with a liquid electrolyte.

2. **Bridging power:** Energy storage can help transition from low output when demands are low ramping up to higher levels of output during peak hours. For example, high-energy super capacitors, lead acid batteries, and flow batteries can store energy for 3 to 4 hour period and discharge very quickly.

Current battery technology allows for the production of hybrid, long-life lead-acid energy storage devices. It combines the fast charging rates of an ultracapacitor technology with the energy storage potential of a lead-acid battery technology in a hybrid device with a single common electrolyte. It can store energy and then release it very rapidly.

3. **Energy management:** Energy storage technologies can shift power from one time period to another. So if you store energy at night you can discharge in hot afternoon.

For example, the latest thermal energy storage tanks can store renewable energy, like wind and inexpensive night-time electricity, in the form of ice for use during peak demand periods.

Or there is pumped hydro technology, which uses off-peak electricity to pump water from a low level reservoir to higher elevation. During periods of high demand, the water is released through turbines to produce electrical power to meet peak demand without over-stressing the power grid.

Distributed energy storage versus grid energy storage

Energy storage can exist anywhere along the energy supply chain, from the plant to distributors all the way to the end users. Today, the most common form is at the end user, otherwise known as distributed energy storage. For example, many commercial buildings can use thermal energy storage to store ice for cooling of the building at a later time. This has proven to be an extremely affective and reliable method for avoiding charges associated with peak demand hours.

This type of storage can count towards the total amount of storage for the California utilities; however the rules for how it will be counted have

not been completely finalized. With the mandate, CA legislators are also envisioning a great increase in grid energy storage, or storing energy within the electrical power grid itself. For example if a power plant production exceeds consumption it can store excess energy for use at a later time – thus production can be maintained at a constant level, with little need to ramp up and down based on demand.

Similar mandates around the world & industry outlook

Today the percentage of energy storage capacity to power created and used globally each year is extremely low. According to the Electric Power Research Institute (EPRI), currently pumped-storage hydroelectricity is the largest-capacity form of grid energy storage available, accounting for more than 99 percent of bulk energy storage worldwide, approximately 127,000 MW in 2012.

However, there are many initiatives globally to increase that number in addition to the CPUC mandate in California. According to a recent article in Environmental Protection, New York will be the next state to consider such a mandate.³ In New York, where real-estate is a premium, the use of distributed energy storage illustrates end users are willing to invest in storage technologies. Already there is over 20 million square feet of New York City office space cooled by ice-based thermal energy storage.

However, the attractiveness of energy storage extends much further south as well. In mid-December 2013, the Puerto Rico Electric Power Authority and the island's main utility released new minimum technical energy storage requirements for renewable energy projects, which states that new renewable energy projects incorporate energy storage equivalent to 30 percent of the project's nameplate capacity for 10-minute frequency regulation applications and 45 percent of the project's capacity for one-minute ramping control.⁴

Final Thoughts

While California may be the first, others will follow. And this is a very good thing. Whether it is thermal energy storage, pumped hydro, batteries or flywheels, integrating energy storage into the grid is the only way to make renewable energy a viable option for our future, while at the same time solving some of our biggest challenges related to T&D deferral, demand response, power quality & reliability, and frequency control. California's mandate of 1,325 MW of energy storage is equivalent to the amount of used in one million homes in one year. That's more homes than there are people in San Francisco, no small feat by any means. But if every city had a similar, or even more aggressive, mandate, think of the benefits it would create.

About the author



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THE BIGGER PICTURE

BY BOB BIGGS



Five Keys to Audit Success

Background

Generation, transmission, and distribution owners and operators (Registered Entities)¹ all have compliance responsibilities related to NERC and NERC CIP standards, aimed at improving reliability of the bulk electric system and securing appropriate cyber assets and supporting infrastructure. Regional Entities (REs)² are obligated to NERC to conduct audits of their Registered Entities' compliance programs and implementation, which can culminate in monetary fines and additional regulatory engagement and oversight.

Demonstrating compliance is made more difficult if entities do not understand the NERC audit processes. Additionally, RE auditors do not always possess the same skill sets or expect the same things and this often results in different methods being applied and additional entity difficulty responding to the auditors. By considering 'Five Keys to Audit Success', entities can assure effective audit preparation and management, facilitate the audit processes, and demonstrate compliance that can be realized on an ongoing basis.

Five Keys to Audit Success

1. *Establish your knowledgeable audit support team well in advance of an audit.*

Entity audit prep teams should be 'standing teams' that remain intact between audits, employing the organization's compliance team (Senior Management, Compliance Officer/Manager, and Subject Matter Experts or SMEs). Some or all of the audit prep team will be your actual audit team.

Entities often do not establish formal audit preparation teams or projects. Additionally, if established, the audit preparation teams are chartered much too late to be optimal. The entity may rely upon a contract organization to conduct a mock-audit; again often too late to be optimal. Many of the teams do not possess all of the skills needed to assure success without difficulty. Personnel that prepare your company for an audit

have a very vital role and are the 'face' of your company. With that in mind, membership on an audit prep team should be considered an honor and an assignment of importance.

While technically knowledgeable, many of the personnel associated with NERC Compliance Program implementation may have little or no experience with the audit process. SMEs may also lack 'soft skills'³ that are highly important during an audit (especially an onsite audit).

Audit preparation takes a dedicated group of folks knowledgeable of the NERC Standards and Requirements, familiar with their organizational structure, trained in the entity's compliance program policies and procedures, and comfortable communicating with regulators.

Key Considerations for Audit Prep Teams

Optimal audit preparation team make-up consists of a Senior Management Sponsor, Compliance Officer or Manager, and appropriate SMEs. A good practice is to know at all times who these members are and to 'press' them into service once an audit schedule is known. This is most easily accomplished by maintaining updated Reliability Standards Audit Worksheets (RSAWs) that have SMEs established for each Standard or Requirement. The Senior Management Sponsor and Compliance Officer or Manager are as assigned in the organization.

- Conduct audit prep team indoctrination sessions to ensure understanding of the team's responsibilities, individual team member responsibilities, and the audit process and schedule.
- Soft skills, such as professional demeanor and verbal communication, must be emphasized through training. All members of an audit prep team must receive training.
- Prepare a project schedule to ensure early and complete audit preparation. This project schedule should use the RE-specific audit timetable, audit specific milestones, and due dates. Each team member should fully understand the audit schedule, process, and specific responsibilities.



- The timeliness, adequacy, and accuracy of responses to the regulator's questions or requests for information (Request for Additional Information or RAI) during an audit are crucial in demonstrating compliance. To ensure success, entities must establish their expectations and communicate this to their organization and especially the audit prep team.
- Prepare the audit prep team and SMEs on what constitutes quality evidence, evidence organization, and how to respond to questions or additional information requests (RAIs) presented by the auditors.
- Conduct a mock audit to 'test' the audit prep team under simulated audit conditions. This mock audit should include industry peers, outside consultants, and internal auditors (if available). Coaching during the mock audit should be minimized. Conduct a debrief to capture lessons learned and address each area for improvement.
- SMEs at the company should assist in preparation of audit responses and be available for additional support both prior to and during the audit.

Audit prep team training and development, both between audit periods and prior to the actual audit, are keys to audit success.

2. *Clearly understand the audit process prior to audit notification by the regulator (RE and/or NERC)*

There are over 1,000 requirements in the approved NERC standards, but not all are part of typical audits in a given year. NERC produces an annual implementation plan that includes an Actively Monitored Standards and Requirements Listing (AML). They are selected out of the universe of NERC standards to cover areas deemed most significant to reliability. Other NERC standards may be included if the RE finds a need to examine them due to triggering events or other circumstances. REs develop an audit plan and consider an entity's compliance history, events, and size (relative to MW and number of functions/assets) to perform a qualitative risk evaluation. REs may expand audit scope and include Reliability Standards and Requirements not identified in the AML. Further, REs may reduce audit scope from AML, but they must notify NERC of their intent to reduce audit scope from AML or make a deferment of a scheduled compliance audit. The scope reduction/deferment form requires justification and submittal to NERC for approval at least 90 days prior to the audit. NERC may make requests for information pertaining to any notifications of audit scope reduction or audit deferments, as NERC ultimately reserves the right to deny any audit scope changes or audit deferments by a RE.

During the audit process and prior to actual conduct, the RE will issue the following items: ⁴.

- **Audit Notification Letter:** Indicates the date of the audit, type of audit – onsite or offsite (table-top), pre-audit instructions,

registration clarification request, audit agenda, auditor contact information, and types of information and data to be provided by the auditee. Additionally, many times links to the RE website are also provided in the notification letter.

- **Pre-audit Survey or General Information Request:**⁵ The RE will ask the auditee to fill out general entity information such as facility description, size and voltage class, neighboring entities, other auditee facilities within the RE's jurisdiction, and most importantly, the auditee must answer specific questions describing its internal compliance program (ICP), and provide evidence supporting each answer. Of importance is a company's compliance program, which is a factor when evaluating penalties for a reliability standards violation.
- **RE auditor biographies:** Entities may object to audit team members in writing (usually 15 days in advance of the audit start) on the basis of conflict of interest or lack of impartiality. Entities' objections cannot generically preclude participation of FERC or NERC representation on any audit. However, entity objections regarding participation by specific individuals will be evaluated based on the merits of the objections raised.
- **Auditor data request (may be included with the Audit Notification Letter):** A RE data request will 1) specify the specific format of the data requested, 2) provide any evidence tables, 3) request specific evidence lists (such as PRC-005 equipment listings) to be used for sample selection, and 4) give instructions on data provision, as well as dates for submittal and how to submit the data. The data requested consists, e.g., of RSAWs, policies and procedures, and supporting evidence.
- **Registered Entity Certification Letter:** RE will provide a certification letter template to be used by the auditee to certify the completeness and accuracy of the audit package prior to submittal to the RE. An officer of the company normally signs this letter; however, on occasion it may be appropriate for the Compliance Officer to sign the letter (depends on organization structure).

3. *Engage the Lead Auditor early and often throughout the audit process.*

The fact that an auditor may have audited other registered entities does not equate to understanding your organization's environment or having an immediate appreciation for how you manage compliance.

Upon receiving the audit notification, an entity's Compliance Officer and/or audit prep team lead should contact the Lead Auditor and get to know him/her. Be sure during initial contact to ask any clarifying questions regarding the RE's audit notification and information requests received. Tell the Lead Auditor about yourself and any key facility operational activities that are ongoing (focus on reliability whenever possible). Let the Lead Auditor know that you are looking forward to sharing your compliance program and its results with him/her and the audit team. Continue to provide updates to the Lead Auditor as you submit information to him/her.



Once the audit entrance meeting has been scheduled, take time and prepare a high-level overview of your facility, organization, and your compliance program. Make sure to discuss any improvements to your compliance program that you have made and that may be ongoing.

Audit Conduct: Most audits last three to five days and are conducted onsite at the audited entity's location or as 'Table Top' audits that are conducted offsite by the RE, using information provided by the entity. During the audit conduct, stay engaged with the Lead Auditor daily to ensure that the Audit Team is receiving all the needed support and information to conduct the audit. Typically, Lead Auditors will provide frequent or daily status updates without any prompting. However, you should establish that you want to receive frequent updates so that no surprises present themselves, and to smooth the process for the RE. When a request for additional information (RAI) arises, seek first to clearly understand the request and the reason for it, take prompt action to fulfill the request, and finally, ensure that the response is complete and accurate.

If, during the audit process, a potential violation is identified, be self-critical, ensure understanding of the requirement, and what the performance deficiency is e.g., failed to meet requirement (action not taken), missing evidence, insufficient evidence/low quality, or not included in the compliance program. If the potential violation cannot be quickly resolved, promptly enter the issue into your corrective action process, take action to restore compliance, determine the cause of the potential violation, extent of condition, and implement action to preclude recurrence. Actions to address potential violations must be taken expeditiously and communicated to the Lead Auditor as soon as possible. Rapid recognition of a performance issue or potential violation and prompt and thorough corrective action demonstrates a healthy Internal Compliance Program (ICP) and satisfies most mitigation plan elements, should one be required. Remember to focus on reliability first.

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4. *Maintain a robust ongoing ICP containing appropriate controls and a self-audit process.*

Audits of NERC Standards and Requirements are scheduled primarily on a three or six year periodicity based upon registered functions. Each year, Standards are revised, a new Standard implemented, or a Standard is retired. Both NERC and the Regions are involved in the Standards process and all are approved by FERC. Along with the dynamic Standards process, entities are continually operating and maintaining their facilities. All of these dynamic processes create an ever-changing and challenging regulatory landscape.

Given that entities must always be and remain in compliance with applicable Standards and Requirements, constant vigilance is needed.

In order to establish a compliance culture, each entity should implement an ICP. This program should be based upon the 13 questions developed from FERC's enforcement guidance. Within these thirteen questions are key programmatic processes that should be implemented.

- Documented compliance policy and procedures.
- Awareness training of personnel in compliance program specifics.
- Wide dissemination of the compliance program.
- Specific training as needed to perform regulatory activities for all relevant staff.
- A corrective action process (find, fix, and prevent recurrence).
- Reliability Compliance Manager/Officer has independent access to the CEO and/or Board of Directors.
- ICP is operated and managed so as to be independent.
- Program has sufficient resources.
- Support and participation of senior management.
- Regular reviews are conducted of the internal compliance program and changes made as appropriate.
- Self-auditing is scheduled for the internal compliance program.
- Accounts for disciplinary action.

Key Actions Indicative of a Strong Compliance Culture

An entity must implement a robust training and communication plan surrounding its ICP. Senior Management should frequently participate in this training plan. Workplace posters, emails, and other awareness tools should be used to promote awareness of compliance.

NERC Compliance policies, procedures, and processes must be developed, taught, implemented, and evaluated for effectiveness. Regulatory policies, procedures, and processes must be controlled and kept current with applicable Standards and Requirements. These procedures must be approved and contain a history of revisions.

Records of all regulatory required activities (training, maintenance, communications, inventories, etc.) must be retained for the specified periods and quickly available for audit.

An effective means to schedule and track regulatory commitments such as self-certifications, NERC Alert responses, actions taken in response to violations, and NERC Standard changes must be implemented.

A corrective action process must be implemented that addresses potential and actual regulatory issues by identifying the issue, determining the cause, and taking actions to correct the specific issue and to prevent recurrence.

Each entity should implement a risk informed self-assessment process that evaluates internal controls for effectiveness and addresses those needing attention. The scheduling of these self-assessments should be developed considering the regulatory risk, potential impact to the bulk electric system, and any routine regulatory audits and self-certification schedules. The entity evaluation should be scheduled independent of any regulatory activity.

Entities should strive to implement a strong ICP that includes all elements of FERC's 13 questions.

5. *Know what the auditors will be looking for to support a compliant conclusion.*

NERC Compliance staff has developed Compliance Audit Directives, Bulletins, and Tools for all Regional Entities to use in performing Compliance Audits and Spot Checks. Their purpose is to provide consistency and objectivity in assessing each Compliance Audit. The Tools [NERC RSAWs] are based on the specific reliability standards to be reviewed during the audit and contain auditor insights, such as relationship to FERC Orders and methods of verification of compliance. These sources and tools must be used to ensure success.

NERC and the REs used to focus mostly on having procedures and policies in place that include regulatory requirements, with some supporting evidence to support a compliant conclusion. Many of the Regions now focus more on operators and SMEs and whether or not they understand and actually operate to their policies and procedures (...discuss/demonstrate for me how you meet...). Robust evidence organization and process mapping are becoming much more common in entities that are highly successful in demonstrating compliance to the regulator.

To ensure success, an entity needs to provide evidence for support of its compliance during the duration of the audit period. REs often request that responses be prepared in searchable electronic formats, whether in the original submittal or subsequent information provided. SMEs at the entity should assist in preparation of responses and be available for additional support and information. In particular, the RSAWs and questionnaires submitted are requested to be in MS Word format. SMEs at the company should assist in preparation of responses and be available for additional support both prior to and during the audit.



When completing RSAWs, ensure that you read and follow what the RSAW instructs. For each requirement you must respond in narrative form on how you are meeting the specific requirement and provide specific references to support your statement. This narrative response should be specific to the requirement and as brief as possible, while conveying the necessary information to demonstrate compliance. A tip is to include an evidence reference when possible to demonstrate proof of process. More complete supportive evidence will be included as necessary.

Evidence supporting compliance should demonstrate a clear line of site to a determination of “compliant”. To address a regulatory requirement, each entity should have processes, procedures, or policies that depict how the entity intends to meet the specific requirement. To prove compliance with these entity processes, procedures, and policies you will have documentation or other means to document the results of the implementing instrument. For example, if a standard and requirement require entity staff training, acceptable evidence would be the procedure that includes the requirement for training, the lesson plan for the training, training attendance sheets for those trained, and evidence, such as shift staffing, to demonstrate that all required personnel actually received the training. Further, it may also be necessary to provide multiple copies of this training evidence depending upon the periodicity of training and the period of the audit. Evidence can take many forms such as screen shots, test records, voice recordings, memos or letters and many more. Of import is that they must be specific, dated, and retained for the specified period.

It is very important to understand what the Lead Auditor instructions are for submitting evidence and data filed for an audit. You must always follow these instructions. Below are a few good practices:

- Create a folder for each Standard.
- Create sub-folders for each Requirement and Sub-requirement.
- Place the RSAW for each Standard in its specific folder.
- Make sure you have implemented the required file naming convention prescribed by the Lead Auditor or agreed to by him/her.

- Within the RSAW, identify all evidence by Requirement and Sub-requirement and place these files into the appropriate folder, as needed.
- You can also create a folder for miscellaneous files that contain additional entity information that is not directly supporting the audit scope, but may be needed should additional questions arise.
- Highlighting of all specific narratives and bookmarks within files is highly recommended.
- Bookmarking electronic files is highly desired; however, many Lead Auditors do not want you to do this because of problems they have had. You may want to demonstrate successful transfer of information and the ability to use the bookmarks if the Lead Auditor will entertain it. In any case, satisfy the Lead Auditor.

REs provide secure portals to submit audit packages. Each Standard should stand alone with the file structure noted above, so creating a folder for each Requirement, Sub-requirement, and the RSAW and the associated evidence is the method most often used.

ABOUT THE AUTHOR

Bob Biggs has more than 35 years of utility experience in generation plant operation and maintenance (fossil, hydro, nuclear, and wind), protective systems, self-assessment programs, facility ratings, and regulatory compliance. He deeply understands the regulatory lifecycle of NERC standards, development, regulatory policies and procedures, Regional Entity audits, findings, enforcement, and mitigation. Formerly the head of Entergy’s Electric Reliability Standards Corporate Compliance Division, Bob is the Services Manager and currently serves as Office of NERC Compliance Services Director for Certrec – a leading regulatory compliance expert that helps utilities manage the regulatory process to their advantage through a suite of Internal Compliance Program solutions.

References

- ¹ Registered Entities will be referred to as entities throughout this article.
- ² Regional Entities will be referred to as REs throughout this article.
- ³ Soft-skills are interpersonal skills associated with effective communication, body language, etc.
- ⁴ This is a typical listing depicting the items regions will request during the audit process. The names can at times be a bit different; however, the contents will be essentially the same.

- ⁵ A registered entity is not required to have a formal company compliance program. This survey is for documenting what your company currently does or does not have in place for promoting compliance inside of your company. The RE, to evaluate any reliability standard violations, will keep this information on file for use. A company compliance program is a factor when evaluating penalties for a reliability standards violation, so please answer the questions accurately because they can be audited.

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By Chris Sincerbox

SECURITY SESSIONS

Exploring Weak Ciphers

– An Explanation and an Example –

Introduction

If utility personnel responsible for cyber security compliance have had any exposure to the Critical Infrastructure Protection (CIP) program sponsored by the North American Electric Reliability Corporation (NERC), then there is a good chance that the term ‘weak ciphers’ has been mentioned in some sort of fashion.

More specifically, if the utility organization has any exposure to independent cyber security vulnerability assessments done by third parties, then it is also probable and perhaps most likely that personnel responsible for cyber security compliance may be even asked to remove ‘weak ciphers’ references from the assessed EMS/DMS/OMS system.

To be concise, a cipher described in the above context refers to the field of cryptography. Cryptography as applied to the control system is the practice and technique for securing data communications between a sender and a receiver. Control system data communications are often transmitted over externally controlled third-party mediums. Some examples of this would be telemetry data transferred over a routable protocol such as DNP; data exchanged between utilities using IEC60870; or control system information presented to corporate users using HTTP/HTTPS. On seeing secure communications, third-party adversaries could not interpret the communications. In contrast the sender and receiver see the same secure communications and are able to exchange information. To do this, a cipher or algorithm for encrypting and decrypting communications is used. Secure communications is typically employed in EMS/DMS/OMS systems where data is transmitted across LANs that are outside of the defined electronic security perimeter (i.e. ESP) or WANs.

Given this scenario, if one is to address the issue of ‘weak ciphers’ some very basic questions need to be answered. For example:

1. What exactly is a weak cipher?
2. How vulnerable is a weak cipher?
3. Who uses weak ciphers?
4. Why are weak ciphers still in use?
5. How does one go about discovering if weak ciphers are being employed?
6. How does one remove weak ciphers?

Weak Cipher Definition

A weak cipher is defined as an encryption/decryption algorithm that uses a key of insufficient length. Using an insufficient length for a key in an encryption/decryption algorithm opens up the possibility (or probability) that the encryption scheme could be broken (i.e. cracked). The larger the key size the stronger the cipher. Weak ciphers are generally known as encryption/decryption algorithms that use key sizes that are less than 128 bits (i.e., 16 bytes ... 8 bits in a byte) in length. To understand the ramifications of insufficient key length in an encryption scheme, a little background is needed in basic cryptography.

Basic Cryptography Background

Cryptography is the process of converting ordinary information (i.e., plaintext) into a scrambled unintelligible mess (i.e., ciphertext). This conversion process is called encryption. The second process of cryptography is called decryption which takes the ciphertext and recreates the plaintext. These processes (encryption/decryption) are controlled by a ‘key.’ The key is a secret that is shared between the two communicating parties. The key is used to cipher the plaintext and to decipher the ciphertext.

Secure communications revolve around four basic components. These four components are: the encryption/decryption algorithm to use on the data to be exchanged, the encryption/decryption algorithm to use for the shared key exchange, the authentication type and the message authentication code.

Encryption Algorithms for Data Exchange

There are two basic types of encryption algorithms. One type uses a symmetric (i.e., same) key (or a shared key). The other type uses asymmetric keys (two keys are used; one key is a private key and one key is a public key). The symmetric key encryption method uses the same secret key (i.e. or session key) to encrypt and decrypt messages. This method is fast and is typically used for data exchange. Symmetric encryption poses an initial session key exchange problem. For example, How does each party securely exchange the same secret key value? This is accomplished by using the asymmetric encryption. The asymmetric method uses two keys:

1. **Public key:** Given freely to the other party. It is used to encrypt the ciphertext
2. **Private key:** Only one party has this secret key. It is used to decode it back to cleartext.

The asymmetric encryption/decryption method is slow compared to the symmetric method but it solves the initial key session exchange problem (the public key is given out freely with no compromise of security).

Encryption Algorithms for Shared Key Exchange

In a secure communication both a symmetric and asymmetric encryption/decryption method are employed. The slower asymmetric encryption approach (public key is distributed, private key is secret) is used to start a secure communication session or tunnel. A symmetric session key is then generated and exchanged securely using the asymmetric encryption session or tunnel started earlier. The subsequent data exchanges are then encrypted and decrypted using the faster symmetric algorithm, which uses the securely transmitted shared session key that was exchanged with the asymmetric algorithm.

Authentication

To prove that a piece of information comes from a certain individual (the term used for this is non-repudiation) or entity digital signatures are used. Asymmetric encryption is used to accomplish this. For example, Fred generates a private and public key. Fred then gives the public key to Gloria. Fred then uses the private key to encrypt a data message and sends this to Gloria. Gloria uses Fred's public key to decrypt the message. This proves the message comes from Fred. This verification of identity is done during the initial setup of a secure communication process. Challenge strings (in encrypted form) are exchanged during secure communication negotiations to verify authentication of both parties.

Hash or Message Authentication Code

The hash or message authentication algorithm is used to create a unique 'fingerprint' of a piece of information (i.e., a transmitted packet). The hash algorithm processes the message to be exchanged

and produces a unique identifier. The hash identifier is always the same fixed size regardless of the amount of data being exchanged. This hash or message digest (i.e., fingerprint) is used to verify that the data being exchanged has not been altered while in transit. The hash value guarantees the integrity of the information without verifying the message content bit by bit. Typically one-way hashes are used (i.e., cannot reverse engineer the hash value). Each secure endpoint calculates a hash value and compares it on both ends. If the hash values match, the message has not been altered in transit.

The more common symmetric encryption algorithms are listed in the Table 1 below:

Symmetric Encryption Name	Description
AES	Advanced Encryption Standard (AES) is specified by NIST in FIPS 197< http://csrc.nist.gov/publications/fips/index.html >. AES is a 128-bit block cipher supporting keys of 128, 192, and 256 bits
DES	Digital Encryption Standard (DES) is described in FIPS < http://csrc.nist.gov/publications/fips/index.html > 46-3. Triple DES Encryption (also known as DES-EDE, 3DES, or Triple-DES) is data that is encrypted using the DES algorithm three separate times. It is first encrypted using the first subkey, then decrypted with the second subkey, and encrypted with the third subkey.
RC4	Rivest Cipher 4 (RC4 or ARCFOUR). See details in RC4< http://en.wikipedia.org/wiki/RC4 >. RC2, RC5 and RC6 are other types of block ciphers that use symmetric keys. The RC groups of algorithms are FIPS non-compliant.

Table 1 - Symmetric Key Algorithms

The common asymmetric encryption algorithms are listed in Table 2 below:

Asymmetric Encryption Name	Description
RSA	The RSA encryption algorithm as defined in PKCS1< http://www.rsasecurity.com/rsalabs/pkcs >.
DH	Diffie-Hellman (DHE) Key Agreement as defined in PKCS3: Diffie-Hellman Key-Agreement Standard, RSA Laboratories, version 1.4, November 1993< http://www.rsasecurity.com/rsalabs/pkcs >.

Table 2 - Asymmetric Key Algorithms

The common hash algorithms are listed in Table 3 below:

Hash Name	Description
MD5	The MD5 message digest algorithm as defined in RFC 1321
SHA1	Hash algorithms defined in the FIPS PUB 180-2.

Table 3 – Hash Algorithms

Grouping the four components together derives a complete cipher suite description. Table 4 presents a list of common ciphers and the individual components used. Kerberos (KRB5) is another form of computer network authentication that uses both symmetrical and asymmetrical approaches to encryption. The number presented after an algorithm is the key size (in bits) used.

The cipher names themselves typically contain the types of algorithms used in each step. For example, DHE-RSA-AES256-SHA contains the four components separated by a dash.

SECURITY SESSIONS

Cipher Name	Protocol Version	Shared Key Exchange	Authentication	Data Exchange Encryption	Message Authentication Code
DHE-RSA-AES256-SHA	SSLv3	DH	RSA	AES(256)	SHA1
DHE-DSS-AES256-SHA	SSLv3	DH	DSS	AES(256)	SHA1
AES256-SHA	SSLv3	RSA	RSA	AES(256)	SHA1
KRB5-DES-CBC3-MD5	SSLv3	KRB5	KRB5	3DES(168)	MD5
KRB5-DES-CBC3-SHA	SSLv3	KRB5	KRB5	3DES(168)	SHA1
EDH-RSA-DES-CBC3-SHA	SSLv3	DH	RSA	3DES(168)	SHA1
EDH-DSS-DES-CBC3-SHA	SSLv3	DH	DSS	3DES(168)	SHA1
ECDHE-RSA-RC4-SHA	SSLv3	DH - PFS	RSA	RC4(128)	SHA1
ECDHE-RSA-AES128-SHA	SSLv3	DH - PFS	RSA	AES(128)	SHA1
DES-CBC3-SHA	SSLv3	RSA	RSA	3DES(168)	SHA1
DES-CBC3-MD5	SSLv2	RSA	RSA	3DES(168)	MD5
DHE-RSA-AES128-SHA	SSLv3	DH	RSA	AES(128)	SHA1
DHE-DSS-AES128-SHA	SSLv3	DH	DSS	AES(128)	SHA1
AES128-SHA	SSLv3	RSA	RSA	AES(128)	SHA1
RC2-CBC-MD5	SSLv2	RSA	RSA	RC2(128)	MD5
KRB5-RC4-MD5	SSLv3	KRB5	KRB5	RC4(128)	MD5
KRB5-RC4-SHA	SSLv3	KRB5	KRB5	RC4(128)	MD5
RC4-SHA	SSLv3	RSA	RSA	RC4(128)	SHA1
RC4-MD5	SSLv3	RSA	RSA	RC4(128)	MD5
KRB5-DES-CBC-MD5	SSLv3	KRB5	KRB5	DES(56)	MD5
KRB5-DES-CBC-SHA	SSLv3	KRB5	KRB5	DES(56)	SHA1
EDH-RSA-DES-CBC-SHA	SSLv3	DH	RSA	DES(56)	SHA1
EDH-DSS-DES-CBC-SHA	SSLv3	DH	DSS	DES(56)	SHA1
DES-CBC-SHA	SSLv3	RSA	RSA	DES(56)	SHA1
DES-CBC-MD5	SSLv2	RSA	RSA	DES(56)	MD5
EXP-KRB5-RC2-CBC-MD5	SSLv3	KRB5	KRB5	RC2(40)	MD5
EXP-KRB5-DES-CBC-MD5	SSLv3	KRB5	KRB5	DES(40)	MD5
EXP-KRB5-RC2-CBC-SHA	SSLv3	KRB5	KRB5	RC2(40)	SHA1
EXP-KRB5-DES-CBC-SHA	SSLv3	KRB5	KRB5	DES(40)	SHA1
EXP-EDH-RSA-DES-CBC-SHA	SSLv3	DH(512)	RSA	DES(40)	SHA1
EXP-EDH-DSS-DES-CBC-SHA	SSLv3	DH(512)	DSS	DES(40)	SHA1
EXP-DES-CBC-SHA	SSLv3	RSA(512)	RSA	DES(40)	SHA1
EXP-RC2-CBC-MD5	SSLv3	RSA(512)	RSA	RC2(40)	MD5
EXP-KRB5-RC4-MD5	SSLv3	KRB5	KRB5	RC4(40)	MD5
EXP-KRB5-RC4-SHA	SSLv3	KRB5	KRB5	RC4(40)	SHA1
EXP-RC4-MD5	SSLv3	RSA(512)	RSA	RC4(40)	MD5

Table 4 – Common Ciphers

Export Ciphers Explanation

From the previous definition of weak ciphers any encryption algorithm used that have key lengths less than 128 are considered weak ciphers. The weak ciphers have been bolded in Table 4. Note that no weak cipher is used in the shared session key exchanges. Many of the weak ciphers identified in Table 4 have an exportable reference (i.e., EXP) contained in the name.

In the U.S. the exporting of strong cryptography was not looked upon favorably by the military. Through the 1990s the U.S. would not allow the export of cryptography that contained key sizes greater than 40 bits. This export ban has been relaxed since then. However, some restrictions still exist. For example, encryption registration is still required with the Bureau of Industry and Security for any encryption exceeding 60 bits. Note that all of the ciphers that begin with EXP in Table 4 have key sizes of 40 bits (the old key size limit that the U.S. would not permit to be exported). The other weak ciphers defined in Table 4 are using 56-bit key sizes which are just under the key size limit (60 bits) the U.S. requires for registration.

Backward compatibility and weak ciphers

Almost all web servers to this day still support weak ciphers. One reason is software backward compatibility. When a web client and web server start a secure session the cipher suite is negotiated. The strongest cipher supported on both sides is used. For example, if a company was using older web browsers that only had support for 40 bit ciphers then the newest web server release (which might be part of a company's deliverables) would need to still support these older outdated ciphers. In the U.S. these older browsers (released pre year 2000) in most cases would not be still in use. But in foreign countries

this may or may not be true. If a company in the U.S. does business overseas it may have to supply web server that still supports the weak ciphers for customers that are still running old exported cryptography in the web browsers. In any case almost all web servers (e.g. Apache/IIS/Tomcat) released today still support weak ciphers. Even more alarming the web servers are often configured by default to enable weak ciphers. In other words one must make an effort to disable weak ciphers for almost any web-based application installation.

Some examples of where third-party web-based applications may be used in a typical EMS/OMS/DMS system include resource monitoring, security monitoring, storage appliance configuration and administration, network appliance administration and configuration, centralized configuration management tools, backup/restore management, and anti-virus configuration and administration. Often commercial off the shelf (COTS) software vendors provide bundled web servers in the standard offerings. For instance, Oracle installations may contain or include a web server that can be used for management and configuration. EMS/DMS vendors may also supply web based access to control systems via lower network security zones (e.g. corporate users needing information, engineers doing studies, engineers doing maintenance). Typically, these types of functions are provided by web-based applications running in a less secure zone (i.e. DMZ).

On a side note, operating system providers may include weak encryption support as a default setting when supplying types of network services. For example, one feature of Microsoft's OS is remote desktop connections. The encryption level used in this application can be altered.

Example of Breaking a Weak Cipher

To get an idea of the difference in complexity between using a key size of 40 bits and one that is 128 bits in length consider the following exercise/example using the RSA algorithm. See http://en.wikipedia.org/wiki/RSA_for_details.

How would one go about compromising the RSA sequence that is used for asymmetric key exchange? One way is to use integer factorization.

- If the public key value of n can be factored, the p and q constants would then be known
- With the p and q constants known then d can be derived using step 5
- If d can be derived then the private key has been discovered. If the private key is exposed the secure session is compromised

One of the best known algorithms for factoring integers is the **General Number Field Sieve** or **GNFS**. This algorithm is freely available, and implementations can easily be downloaded. Efficiency strides have been made to this algorithm in the last several years. See results below in Table 5 for the time GNFS took to factor various sized keys (i.e., n). The sieve implementation used for this exercise was executed on a Windows Operating system using an Intel i7 processor (8 logical CPUs) running a clock speed of 2.6GHz with 8GB of RAM. The sieve implementation used was single-threaded.

SECURITY SESSIONS

As shown below, key lengths less than 128 bits could be factored with ease. A more robust multi-threaded (i.e., a form of multiprocessing) sieve variant algorithm could easily improve the elapsed times. Key lengths greater than 192 bits exceeded the selected sieve implementations capabilities (e.g., the application took many hours to complete). Be aware that not too long ago factoring integers that were 128 bits in length was considered not feasible.

Note that the typical RSA session for initial key exchange uses anywhere from 512 to 4096 bits in key length depending on the implementation.

Key Length (bits)	Modulus (n)	Prime Numbers (p/q)	Elapsed Time (h:m:s)
16	3019486481	43343/49233	00:00:00
32	5663448140013535621	8218275484/7939621347	00:00:00
48	253974110824639185833933794753547676237	18183843954871794523 /74028739494043801719	00:00:51
128	794211373784429728720480896125644187973609237 9356897779892428578454308724889	318163227961721866488314454 1422889632637 31248273871908629388991839 562889218347	00:04:41
192	15843214467520374288329472914675830278767321417086 15843214467520374288329472914675830278767321417086 87483425796294623684239452087522827989367489829	11564753475642804951051769 38249884427942700047 1378345682582179228051374 307163749909243624087	02:45:38

Table 5 - GNFS Results

How would one go about compromising a symmetric key? One simple way is to use brute force. If one knew the cipher type negotiated, one could attempt to decrypt a captured data pattern repeatedly by trying every bit combination possible (sort of like password cracking) within the key size until a correct result is obtained. This type of problem can easily be distributed across several computers or CPUs within a single computer to speed the process up. For example, thread one would be responsible for evaluating key values 1-n, thread two would be responsible for evaluating key values n-x, and so on. These threads would all run at the same time. See results below in Table 6 for sample times. As shown below, key lengths less than 60 bits could be factored with ease. A more robust multi-threaded brute force algorithm could easily improve the elapsed times.

Key Length (bits)	Number of threads/Number of CPU's	Average Elapsed Time (h:m:s)
64	64/24	11:34:40
56	64/24	13:8:22
48	64/24	10:37:34
40	64/24	4:57:28

Table 6 - Brute Force Results

Discovering and Removing Weak Ciphers

How would one go about discovering weak ciphers that have been employed onto the system? Third-party scanners could be one option. One other way is to use the 'openssl' command. When documenting ports and services used in the control system web servers are identified. If OpenSSL is available (freely downloaded) the identified web-based server could be interrogated with the following command: 'openssl s_client -connect <hostname:port> -cipher.' This interface would contact the hostname/port specified and negotiate the lowest security cipher supported. If any ciphers are returned from they must be removed. The command 'openssl ciphers LOW -v' could list weak

ciphers defined.

Removing a cipher is specific to the web server application. Different configuration methods are provided. With more customized applications, the configuration methods may not be apparent (e.g., setting an encryption level on a configuration web page). Listed below are some of the more generic configuration methods.

If the application software is using Apache as the web server, use the SSLCipherSuite option and insert the following into the ssl.conf file as follows:

```
'SSLCipherSuite ALL:!ADH:!SSLv2:!EXPORT56:!EXPORT40:!RC4:!DES:+HIGH:+MEDIUM:+EXP'
```

If the application software is using Tomcat as the web server, use the 'ciphers' option in the server.conf file as follows:

```
'<Connector port="8443", ciphers="SSL_RSA_WITH_RC4_128_SHA,
TLS_RSA_WITH_AES_128_CBC_SHA,
TLS_DHE_RSA_WITH_AES_128_CBC_SHA,
TLS_DHE_DSS_WITH_AES_128_CBC_SHA,
SSL_RSA_WITH_3DES_EDE_CBC_SHA,
SSL_DHE_RSA_WITH_3DES_EDE_CBC_SHA,
SSL_DHE_DSS_WITH_3DES_EDE_CBC_SHA"/>'
```

If the application software is using Microsoft IIS as the web server, use the provided registry keys to disable weak ciphers as follows:

```
"HKEY_LOCAL_MACHINE\SYSTEM\CurrentControlSet\Control\
SecurityProviders\CHANNEL\Ciphers\RC2_40/128" Enabled = 0
```

Conclusion

With enough time and money, any encryption algorithm can be compromised very quickly (think NSA). However, weak ciphers are so vulnerable even my feeble attempts to compromise them are successful with today's computers. Just spreading brute force methods across multiple machines can have dramatic impacts on elapsed times. In summary, weak encryption is supported by most web server applications. Programs to crack weak ciphers are easily created and obtained. Great strides have been made on improving cracking techniques. Older web-based client (pre-2000) software needs to be upgraded. And, changing web server default configurations to remove weak ciphers is not difficult.

ABOUT THE AUTHOR

Chris Sincerbox holds a bachelor's degree from New Mexico State and a master's degree in Software Engineering from the University of Houston at Clear Lake. He has worked in all system aspects of energy management systems for the last 28 years. This experience includes designing and implementing security compliance for existing EMS production systems as well as Distribution Management systems. He is currently employed at ABB/Ventrix as a Consulting Engineer.

Real-Time Operational Systems

Is Common Technology Right for You?

By Joe Moran, PE



Supervisory Control and Data Acquisition (SCADA) has been a mainstream mission critical utility real-time system for decades, primarily used to monitor and control the generation and transmission system in real-time. Most utilities did not expand the reach of SCADA down the distribution network, since the operation of radial and 'passive' distribution networks was historically straightforward.

Recent changes drive the need for utilities to reevaluate their real-time operational systems strategies and to consider migrating to a common technology solution for transmission and distribution SCADA to support Energy Management Systems (EMS), advanced Distribution Management Systems (DMS) and Outage Management Systems (OMS). Common technology solution refers to a common transmission and distribution SCADA system provided by a single vendor – this can take the form of either a single instance of the vendor's SCADA software or separate instances of the same vendor's SCADA software (one for transmission and one for distribution).

Drivers for common SCADA technology include:

- Smart grid technologies provide utilities with the opportunity to gather significantly more data from the transmission and distribution grids.
- New technologies at the customer side of the meter (e.g., electric vehicles and distributed generators) make the distribution network increasing more complex to operate.
- Pressure on utilities to restore power more quickly and minimize customer outages during storms is driving some utilities to install more automated field devices on the feeders to pick up customers on unfaulted sections of the feeders more quickly.
- Advanced DMS power applications such as unbalanced power flow, distribution state estimation, integrated volt/var control, and fault location, isolation, and service restoration are now starting to become important applications in distribution operations to manage, operate, optimize, and restore the grid in real-time.

These changes, along with the effect of such trends as the aging workforce on operations and support, will lead some utilities to

consider the benefits and costs of whether or not to consolidate to a common transmission and distribution SCADA system to support EMS, DMS, and OMS. Before considering a move to a common vendor SCADA system solution each utility should revisit their real-time systems roadmap based on their unique situation, answering key questions and assessing potential benefits and costs of a common SCADA system technology approach.

REAL-TIME OPERATIONAL SYSTEMS

SCADA systems have been core utility systems for many years. SCADA systems allow operators in control rooms to monitor the flows in the power system and to remotely control substation equipment, issuing control commands via the utility's communication network. Other fundamental components of a SCADA system include functionality to alarm abnormal conditions, tag devices for safety and information purposes, and archive real-time data.

The SCADA system communicates with Remote Terminal Units (RTUs) (or substation data concentrators fed by substation intelligent electronic devices) located within substations. Most current deployments of SCADA systems have been used to monitor and control equipment on the transmission and sub-transmission network as well as distribution transformers and feeder head devices located within the substations. However, electric utilities are facing new challenges that may be best addressed by a common technology solution for both transmission and distribution SCADA to support EMS, advanced DMS and OMS.

Energy Management

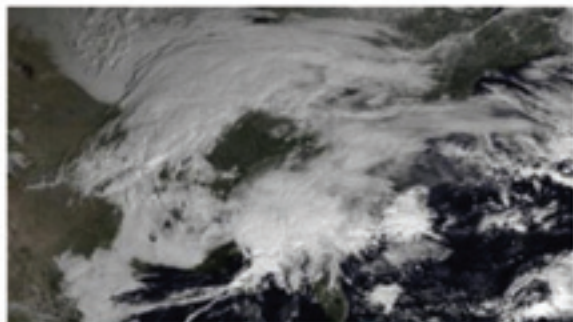
The energy management system (EMS) manages the operation of the bulk power grid. It is considered a mission critical system since the potential consequences of losing visibility and control of bulk power grid operations are so severe. The SCADA system retrieves the real-time measurements and status conditions reflecting the topology of the power system for use by automatic generation control (AGC) and advanced power network applications such as state estimation, operator power flow, and contingency analysis.

The AGC application uses generator and tie line measurements to adjust generation to match load to maintain the appropriate frequency at 60 Hz while maintaining scheduled tie flows. The SCADA system provides real-time measurements to the state estimator to allow it to compute voltages and flows for the entire power grid including substations that do not have RTUs to provide operators with a picture of the current state of the power system. The state estimator results are then used by the contingency analysis application to run many contingencies (e.g., removing a line or generator, etc.) to provide a picture of what could happen to the power system (e.g., losing a transmission line could create an overload situation on another line), if that contingency occurs.

Distribution Management

Advanced distribution management system power applications such as unbalanced power flow, distribution state estimation, integrated volt/var control, and fault location, isolation, and service restoration are now starting to become important applications in distribution operations to manage, operate, optimize, and restore the grid in real-time.

Many utilities started with pilot projects to get a better understanding of the realizable benefits of advanced distribution management applications such as integrated volt/var optimization, and centralized and distributed control to speed up the process of locating, isolating, and restoring power to unfaulted feeder sections. These pilot projects have shown the potential benefits of these applications, resulting in a number of utilities moving from the pilot stage to full procurement and implementation of DMS to provide distribution operators with visibility and control of their distribution network. The integration of the real time data with data obtained from advanced metering infrastructure (AMI) devices and other feeder devices in some of the pilots has helped to improve the accuracy of fault isolation leading to faster restoration times. The integration of SCADA and DMS into a single system provides the operators with a common user interface to use in restoration of the network. As utilities move to SCADA for distribution and the ability to bring back a significantly larger amount of data, assessing the advantages and disadvantages of using common SCADA technology will be an important action to take.



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Outage Management

Recent major storms have created pressure on utilities to implement process changes to restore power more quickly and to minimize customer outages during storms. This is driving some utilities to install more automated field devices. Another trend is the consolidation of separate OMS and DMS into a single fully integrated system. The combined functionality enables the distribution operator to view the latest customer outage information, distribution equipment status information, and crew availability on a single screen, vastly improving overall situational awareness and management of outage events.

Devices being added along the feeders are often connected to the SCADA system to bring back telemetry and provide control. By having a common system for the field devices and the substation, an operator can easily navigate between the two environments without having to deal with the differences in operations. Switching orders generated via the OMS use the SCADA system to issue the control actions for remotely controllable devices.

Smart Grid Technologies

As smart grid technologies continue to be deployed on circuits yielding a plethora of data, the SCADA will interact with RTUs, smart devices, and sensors on the distribution circuits. While AMI will be used separate from the SCADA system to monitor consumption at the customer premises and allow for 'pinging' the meter to ensure the customer's service is restored after an outage, SCADA provides the necessary real-time information to execute generation control, transmission power network analysis, and distribution network analysis applications.

Smart grid data can be used to either supplement or improve the solution of applications designed to monitor and control the power grid. The key element to consider is whether the data can be provided in real time for the applications or for after the fact studies. If in real time, the SCADA system becomes the best vehicle to get the data into the applications already used by the operators. Data not needed from these devices for the real time control of the system is better used by non SCADA systems outside the control room. This data, however, with some manipulation can be used to improve the network models in the EMS and DMS system (for example, in improving the load models of transformers in substations or distribution feeders).

Smart grid also brings increased complexity of the distribution network due to new technologies on the customer side of the meter (e.g., electric vehicles and Distributed Energy Resources (DER)). Much of the activity in distribution grid modernization is centered on DERs, which include distributed generators (DG),

distributed renewables (wind and solar power), energy storage units, and controllable loads (i.e., demand response). The distribution SCADA system can provide monitoring and transfer tripping of larger (utility scale) DG units. As the industry gets deeper into managing DERs, the distribution SCADA system will interact with a Distributed Energy Resource Management System (DERMS) that is managing and controlling customer premises equipment (e.g., electric vehicles, solar PV and demand response) which generally do not use SCADA protocols and standards. The advanced distribution power applications in the DMS will need the information from these types of applications directly from SCADA or via an interface between the DERMS and the SCADA for the DERMS to provide the data.

KEY CONSIDERATIONS FOR COMMON SCADA TECHNOLOGY

Utilities have several options for their real-time systems roadmap:

- 1) Separate SCADA systems from different vendors: A transmission SCADA system for the transmission and sub-transmission network and a distribution SCADA system for the distribution system.
- 2) Common SCADA system technology from the same vendor: This system scans and controls all of the utility's equipment and provides the data to EMS, DMS or OMS applications that need it. This option also includes running two different instances of the same SCADA vendor technology.

The option that a utility chooses will have impacts on operators, maintenance and support staff, engineers that need to data for reliability studies and after the fact analysis, vendor contract management, and the utility's cost and flexibility to adapt to changes that will inevitably come about during the entire system life cycle.

Table 1 highlights some of the key considerations that should be evaluated for each SCADA system option as part of a SCADA system roadmap effort. Each utility needs to understand its own needs and priorities by discussing the questions below with a diverse team of staff including operators, business analysts, power network analysts, and support staff. Discussions are needed to understand how the utility priorities align with the benefits and costs of each option and the overall utility vision for its real-time systems over the next decade or more.

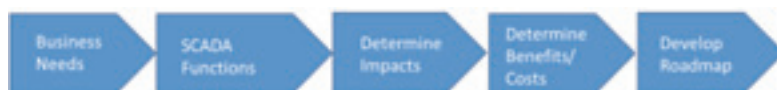
Table 1: Key Considerations for Evaluating Common SCADA Technology

Considerations	Sample Questions
Human Resources/ Staffing	<ul style="list-style-type: none"> What is the impact of each option on operators and support staff (e.g., complexity, cross-training, etc.)? How does each option impact labor requirements to operate? What is the impact of aging workforce - which option ensures sufficient staffing with adequate knowledge transfer?
Redundancy	<ul style="list-style-type: none"> What are the risks of having a common system all go down at once? What is the level of duplication that needs to be supported? What are the costs associated with duplication?
Architectural Implications	<ul style="list-style-type: none"> How does each option support real-time systems high availability and performance requirements? How does each option support disaster recovery plans? With a combined system, can disruptions to distribution impact transmission?
Best-of-Breed Solution	<ul style="list-style-type: none"> Are there benefits to separating transmission SCADA from distribution SCADA in order to have an integrated B-O-B solution (e.g., transmission SCADA integrated into EMS and distribution SCADA integrated into DMS)? If so, do the benefits of having best of breed solutions outweigh the potential for higher costs?
Cybersecurity and NERC CIP	<ul style="list-style-type: none"> What are the CIP implications of integrating T, D and OMS? How does each option impact NERC CIP requirements for applicable registered entities? What would be the extra requirement for monitoring patches for 3rd party software used in each vendors' SCADA system? How could a cybersecurity event impact the real-time system infrastructure?
Life Cycle Costs	<ul style="list-style-type: none"> What are the maintenance costs associated with multiple vendor/ system solutions? What support staff required for support of the systems? What are the training requirements for the support and operations staff?
Operational Impacts	<ul style="list-style-type: none"> What is the exposure to the business due to a failure in one area of the SCADA system affecting the rest of the system? What kinds of mitigation plans can be developed and what are their associated costs?
Regulatory Impacts	<ul style="list-style-type: none"> What are the regulatory impacts of having combined systems? Is there exposure to the business due to a failure in one area affecting the rest of the system? What are the costs and benefits of a good redundancy plan and backup system?

DEFINING THE SCADA SYSTEM ROADMAP

Key activities for making a decision on which SCADA system option to pursue include understanding business needs, delineating current and future SCADA functions, assessing impacts of each option, and analyzing the benefits (where many benefits may be subjective in nature), as well as developing a good understanding of the life cycle costs. Figure 1 below highlights the components of this decision process.

Figure 1: Approach for Defining SCADA System Roadmap



Business Needs

The initial step in the process is to understand the business needs. To do so requires discussions with the utility executives on their vision of the utility's future, system operators and dispatchers, business analysts, other groups that need SCADA data, operations engineers, power network analysts, and support staff. By identifying and prioritizing the business needs from a diverse set of utility staff, the team can evaluate how well each alternative meets their needs. Developing the business needs requires understanding the business drivers that the utility will be faced with (e.g., need for improved system resiliency, regulatory requirements, resource needs, cost pressures, etc.). Since the SCADA system will need to support the needs of the utility over a long period of time, it is important to understand the short term needs as well as longer term needs.

SCADA Functions

This may seem straightforward since SCADA has been used for many years. However, it is important to understand how SCADA will fit in your plans for the next 10 – 15 years. For example, will you be adding more automated field equipment (smart devices, sensors, Phasor measurement units (PMUs), etc.) that includes the capability to bring back additional measurements or needs to interact with distributed energy controls or microgrid control systems? Will SCADA need to interface to a DERMs? Will SCADA need to provide information for any company initiative related to grid analytics? Will SCADA be tied to components of asset management? These requirements will also include the user preferences on how to visualize the system for situational awareness, intelligent alarming, improved safety coordination and interaction with distributed control systems, automatic "self-healing" applications, and cybersecurity. Each of the SCADA system options needs to be evaluated related to the set of SCADA functions and needs.

Impacts

The questions in Table 1 can be used as a starting point to explore the impacts on the users and support staff as well as the ability to leverage your investments in smart grid technologies cost effectively and efficiently. Understanding the impacts is needed to relate them to benefits and costs of one option versus another.

For instance, will a particular option require additional staff for support resulting in higher life cycle support cost? In assessing the impacts, consider the possible remedies to minimize these impacts. The impact assessment should include a measurement of the degree to which the issue impacts the costs or the benefit. For example, a common set of SCADA maintenance tools will have a significantly higher benefit to the support staff than having different tools to maintain different systems) along with the associated higher costs of two tools versus one.

Benefits and Costs

A good life cycle cost analysis for the two different options needs to be prepared in order to understand the full cost impacts of having a common SCADA system versus separate SCADA systems.

Each SCADA system option will have areas that are of benefit to the utility, based on the utility's specific needs and requirements. It is important to understand how those benefits align with the utility's business needs and priorities. It is important to consider benefits that are quantifiable (e.g., reduced cost of maintenance for common versus separate vendor systems) as well as subjective benefits (e.g., ease of use for the operators by using a common user interface). The team needs to also develop the life cycle costs (e.g., maintenance and support costs, staffing costs, etc.) for both options to understand the differences between the two options. By evaluating the benefits and costs of each option, the utility can determine the best option that fits its specific circumstances.

Roadmap

The final roadmap will provide the utility with a path forward for its SCADA system strategy that is aligned with its needs and smart grid vision. The roadmap defines the required actions to execute on the best option for the utility including expected

expenditures throughout the expected life of the system. The roadmap will be aligned with the cash flows needed to either have separate SCADA systems or move to a common SCADA system vendor solution and then to keep the SCADA system updated over a defined life cycle period (e.g., 10 years).

SUMMARY

Emerging trends and changing dynamics are affecting how electric utilities monitor, operate, and control their assets. More and more utilities are seeing the potential benefits of DMS and smart grid, with SCADA being a key provider of real-time telemetry. It is a prudent step for utilities to evaluate how SCADA will support their transmission and distribution systems by developing a SCADA strategy that will meet the utility's needs in the short and long term.

ABOUT THE AUTHOR

Joe Moran is Senior Vice President of Consulting and Design at UISOL, an Alstom Company. He has 29 years of utility industry experience across real-time system technology and strategic planning. Prior to joining UISOL, he led the EMS/SCADA/DMS and NERC Compliance groups at DNV Kema. Moran holds BS and MS degrees in electrical engineering and an MBA, and is a registered PE.

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