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Juliet Shavit
How to Pump Up the Volume on Smart Grid Customer Education

Electric Energy T&D MAGAZINE

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POWERPOINTS

No Joy at Christmas

Just days before Christmas, the weather offices were blasting warnings by the hour that Southern Ontario was going to find itself in the throes of an horrific ice storm. I wasn't there in 1998 when the eastern part of the province and much of southern Quebec were throttled by the worst ice storm in living memory. I do, however, remember writing an article about it and my research took me deep into the bowels of the story. A real human interest story, which ended in tragedy with the death of 25 people.

Now we regale people about our own fight with the ice. Like many people I listened to the forecasts but didn't really hear them. We've had freezing rain before and it was never enough to get your knickers in a twist and I proceeded with my chores on that basis. I was busy getting all of the elements together to co-host a Christmas Eve dinner with family and friends. My responsibility included preparing the turkey and doing up a few plates of nibblies. One of my closest friends was hosting the event at her place, a spectacular 2-storey unit looking south over the Don Valley, which instead of showing us a kilometer of snow-covered evergreens and deciduous trees, the land absolutely sparkled as far as the eye could see.

I turned a table and a few cardboard boxes into a fridge/freezer just outside my back door, which worked out perfectly for the duration. I am also an avid camper so I pressed my large rechargeable lantern, head light, propane and backpacking stove into service. My son and his lady friend were joining us and supplied another backpacking stove. A supply of 8-hour emergency candles is always useful. The only real inconvenience was that I had to recharge my phone and the other batteries using the inverter plugged into the car.

My power disappeared during the early morning on Monday the thirtieth. Thus began life in the darkness. The following morning I was able to get through to the Toronto Hydro hotline to hear the message that as of then over 264,000 of my Toronto neighbours and nearly 200,000 residents in the Greater Toronto Area (GTA) were without joy. The message also stated that people should be prepared to tough it out for at least 72 hours. Three days minimum – so long Christmas tree lights!

This was one of the worst ice storms to hit Toronto in several decades. Rob Ford, our well-known mayor went public to ensure the city that council members were standing by to provide any help they could. Those who still had power heard him say just that.

Any home reno stores that were open sold out of generators and flashlight batteries in hours and emergency candles flew off the shelves from every store that had them.

Near to me a small strip of stores had power. Luckily, one of the retailers was a larger grocery store. I slipped and slid my way to the area but checked the state of my car just in case I could use it while I was out. Some 10 centimetres had formed and, of course, the ice scraper was sitting inside. Besides, the police were asking people not to attempt driving unless extremely necessary. When I got to the store, it was like a day at summer camp.

Everyone was in a good mood and like all Canadians, treating this like a good adventure. For every person in the check-out line there was at least one tale of woe that was apprised with humour. “Being without power,” someone said, “is like listening to a mime on the radio. “That alone was worth the slog. On my return I was able to crack the layer of ice preventing the driver door from opening and got in so I could start charging batteries. “Forget the ice on the rest of the car,” I thought. “That’s why we have spring.”

At the peak of the problem, Toronto Hydro was faced with more than 90 large-scale outages. All available forestry workers were hacking and slashing fallen tree limbs and bushes clearing the way ahead of the hydro crews. Anthony Haines* CEO of Toronto Hydro was giving constant updates and for those that could hear said, ”We continue to be in the middle of the storm. The damage continues to be done as we speak. We will not rest until such time as we’ve fixed it.”

Toronto Fire said they received hundreds of calls and attended downed wires that were still hot and the city brought in every available police officer to help wherever they could.

Luckily, both Sunnybrook Health Sciences Centre and Toronto East General hospital stayed alive with back-up gennies. A good thing too – six premature newborns entered the world amidst the icy chaos.

VIA freight and passenger rail lines as well as the GO commuter trains were closed with hundreds of broken trees lying across tracks. The subway system was shut down by breaks in the power flow. This problem was intensified because dozens of electric streetcars were stranded across the downtown as the overhead copper power wires continued to sag under the ice. Both Pearson International and Billy Bishop Airports were forced to cancel dozens and dozens of flights. Our newest water treatment plant and several pumping stations were put out of commission.

Norm Kelly, our Deputy Mayor put it the way I did. “This is the universe putting us in our place.” My take was similar. In my frustration, I felt, “Well you’ve proved you can beat us. Your point is made. Now it’s time to quit.”

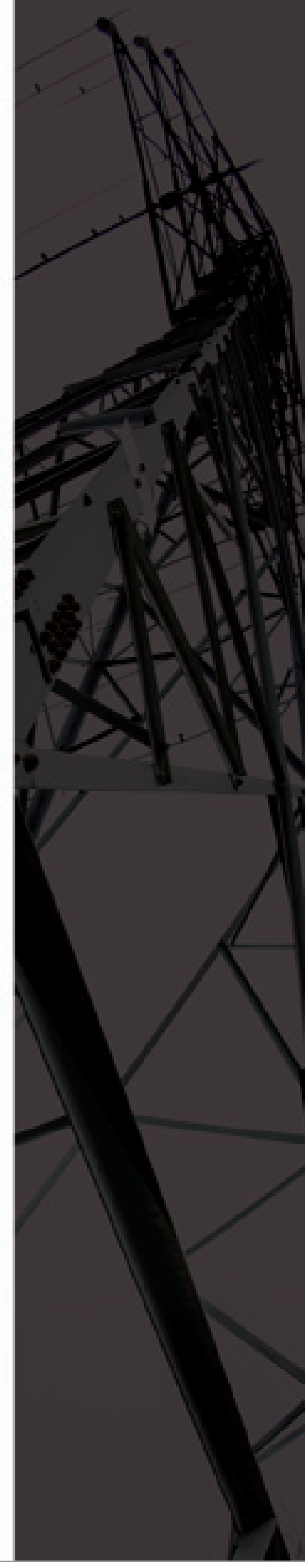
Our Mayor, who had previously been stripped of many of his powers for acts unbecoming a City Official still had the authority to declare Toronto a disaster zone. By doing this Federal and Provincial money would automatically be funnelled into the coffers to meet repair costs. Ford didn’t do it so we got no emergency funds. As I write this, all of the GTA mayors are meeting to draft a proposal to the Ontario and Canadian governments to send CA$106 million to finish the street clean-up and repair damage to city property. Toronto Hydro claims the extra CA$13 million it spent to get everyone back on line will not be found in the pockets of the ratepayers. I wish them luck with that one. Another thing was uncovered by the Hydro crews. They found hundreds of houses that had work done to the electrical panel (pony boxes, etc.) and/or wiring obviously not done by a certified electrician – a fire looking for a place to happen! The power for those residents was to remain in the “off position” until the illegal work was corrected and signed off by both an electrician and the utility.

This might sound odd coming from an editor, but when I had power back and was able to watch the news on TV I was frustrated by the amount of airtime dedicated to telling us how many people were still without power. Slow news days are a pain. I was also pissed at the fact the on-air newscasters kept egging people on saying they were entitled to make someone pay for all of their troubles. I say that if you can find the culprit, “Be my guest. Sue the living hell out of them.” Again, good luck with that one. My experiences during this were somewhat of a challenge (cold showers) but to seethe over the thing was only going to precipitate heart failure. We were all in it together and we’re all out of it together. Thankfully, no one lost their life. Just think of the stories to tell the grandchildren. And don’t forget to inject some humour.

As for Christmas dinner, I cut up the turkey and baked it in the barbeque. My friend turned her patio into a fridge cum kitchen and prepared tasty potatoes, several veggies, gravy, and cranberries on her barbeque and the portable stoves. We sat down to a delightful candle-lit table filled with good food, good drink, and great company. We had fun the entire evening. Just like my Dad used to say, “If you can’t have at least some fun, why do it?”

My power came back on about one minute before midnight on Christmas Eve.

*Please see the cover story on Mr. Haines in May-June 2013 issue of Electric Energy T&D print and digital magazine.



INDUSTRY NEWS

Independent Electricity System Operator Releases 2013 Ontario Electricity Data

Ontario's Independent Electricity System Operator (IESO) released 2013 statistics on January 8 for electricity supply, demand and price in the province.

"Ontario's electricity data for the past year reflects what we are seeing day-to-day on our Control Room floor - lower demands, increased local generation and an overall greater reliance on base supply," said Bruce Campbell, President and CEO of the Independent Electricity System Operator.

"Yet it is only a snapshot in time. Ontario's electricity system will continue to evolve over 2014 and beyond with the introduction of solar energy to the grid, demand response and wind generation developing critical mass as well as the nuclear refurbishment program."

Supply

Ontario's reliance on nuclear energy increased over the last year, as it continued to account for most of the province's baseload needs - roughly 60 per cent of total production. Other baseload supply such as hydro and wind generation output also increased - to 23.4 per cent and 3.4 per cent respectively.

Gas generation output decreased by more than three per cent to 17.1 TWh, a result in part of lower demand peaks throughout the year. Coal generation, which by the end of 2013 had ceased production in southern Ontario, generated only 2.1 per cent or 3.2 TWh of total production. Electricity imports from neighbouring jurisdictions were also slightly up to 4.9 TWh in 2013, while exports rose to 18.3 TWh.

The following table shows Ontario supply by fuel type for the last five years:

Year	Nuclear	Hydro	Coal	Gas	Wind	Other
2013	91.1 TWh 59.2%	36.1 TWh 23.4%	3.2 TWh 2.1%	17.1 TWh 11.1%	5.2 TWh 3.4%	1.3 TWh 0.8%
2012	85.6 TWh 56.4%	33.8 TWh 22.3%	4.3 TWh 2.8%	22.2 TWh 14.6%	4.6 TWh 3.0%	1.3 TWh 0.8%
2011	85.3 TWh 56.9%	33.3 TWh 22.2%	4.1 TWh 2.7%	22.0 TWh 14.7%	3.9 TWh 2.6%	1.2 TWh 0.8%
2010	82.9 TWh 55.0%	30.7 TWh 20.4%	12.6 TWh 8.3%	20.5 TWh 13.6%	2.8 TWh 1.9%	1.3 TWh 0.8%
2009	82.5 TWh 55.2%	38.1 TWh 25.5%	9.8 TWh 6.6%	15.4 TWh 10.3%	2.3 TWh 1.6%	1.2 TWh 0.8%

Due to rounding, percentages may not add to 100.

Demand

Demand for electricity in Ontario remained largely unchanged over the year, with overall consumption at 140.7 TWh. This figure represents a slight decrease from 2012, which was a leap year.

Local, or embedded generation, and demand management efforts have contributed to flattening demand for electricity from the provincial power grid.

The IESO estimates that peak demand was reduced by an average of 1,200 MW during peak days last summer as a result of demand management efforts such the Global Adjustment Allocation, DR3, large consumers participating in the market (also known as dispatchable load) and time-of-use rates.

Mother Nature also triggered a number of unexpected demand reductions during 2013. On July 8, severe floods resulted in a demand drop of approximately 3,800 MW as thousands of customers lost electricity service across the GTA. This was the greatest loss of load since the 2003 blackout which affected most of the province. The recent ice storm resulted in a loss of an estimated 1,800 MW in demand during the early days of the outage, with continuous load losses over the remainder of the week.

Price

Total cost of power in 2013 was 8.55 cents per kilowatt-hour (kWh), up from 7.37 cents in 2012. This cost includes the average weighted wholesale market price of 2.65 cents/kWh and the average Global Adjustment of 5.90 cents/kWh.*

The IESO is responsible for managing Ontario's bulk electricity power system and operating the wholesale market. It provides a range of historical and real-time electricity data, such as hourly demand, generator output and prices on its web site at www.ieso.ca

**incorporates an estimate for the December 2013 Global Adjustment*

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Itron Extends Contract with ScottishPower for Full Suite of Prepayment Managed Services

Itron to continue providing prepayment support to more than 500,000 ScottishPower customers

Itron, Inc. (NASDAQ: ITRI) announced that it has signed a three-year contract extension with ScottishPower to provide a full suite of managed services in support of more than 500,000 electricity prepayment customers throughout the U.K. Itron will continue to help manage ScottishPower's business processes and day-to-day tasks, including meter data, transaction and report management. Itron has provided ScottishPower with managed services since 2006. This agreement will bring Itron's support of ScottishPower past the 10 year mark.

Using Itron's unique managed service offering and prepayment expertise, ScottishPower can operate more strategically at a lower cost and offer their customers continuing support as the UK transitions into smart metering.

"Prepayment metering in the U.K. is a complex operation that requires significant back office support. Itron's professional delivery of their range of managed services translates well into improved consumer engagement and cost efficiency for ScottishPower," said Colin Blair, Commercial Manager at ScottishPower. "We look forward to continue to work with Itron to deliver prepayment to our customers."

Itron's Managed Services provides prepayment services to more than 3.4 million homes across the U.K., including collection and processing of prepayment meter data (such as vending, debt and credit details) as well as issuing prepayment keys, providing tariff updates and delivering solution support. "We are very pleased to continue our relationship with ScottishPower by providing them with services to drive improvements in customer service and business efficiencies. Our work with ScottishPower is another great example of the value our customers place on Itron's knowledge and expertise combined with our capability to consistently deliver industry leading services," said Nigel Hughes, Itron vice president of sales, marketing & deliveries for Energy in Northern Europe.

Inland Power & Light Selects Tantalus and Itron for Smart Grid Communications Network

Tantalus expands presence in rugged Pacific Northwest territory through joint project

Tantalus, a leading provider of real-time smart grid communications, and Itron Inc. (NASDAQ: ITRI), a world-leading provider of technologies that help utilities measure, manage and analyze energy and water, announced that Inland Power & Light (IPL) has selected a Tantalus-Itron solution for public power to provide advanced metering infrastructure (AMI) and smart grid services for the approximately 39,000 members in its cooperative in eastern Washington and northern Idaho. The fully integrated TUNet® - Tantalus Utility Network – platform will serve as the core foundation for IPL to deploy Itron AMI-ready meters to facilitate the use of advanced applications such as automated metering, interval meter data collection, prepay, and power quality management.

"After an extensive investigatory and technology review process, IPL has selected the Itron-Tantalus solution for our utility communications network/services deployment," said John Francisco, Chief of Energy Resources for IPL. "It was important for us to select a long-term technology solution which we felt would provide reliable two-way coverage for our large and geographically challenging service territory, leverage our existing network of communications infrastructure, and prove to be a valuable resource for our membership and community. This was a stringent list of requirements, but after completing our due diligence process and working with several utilities across the country that use this solution, we felt certain that the Itron-Tantalus joint offering was the ideally matched solution to meet our needs."

IPL's initial deployment plans centered on a power line carrier (PLC) solution due to the availability of existing powerlines and widespread adoption among rural electric cooperatives. However, the inherent limitations in data delivery speed and distance with PLC as well as the extensive upgrades and additional maintenance to substations that IPL would have had to undertake made the solution difficult to justify for a long-term smart grid business case. After reviewing propagation studies of TUNet's unique terrain-hugging 220 MHz WAN and 900 MHz LAN hybrid RF network, IPL concluded that real-time, bandwidth-heavy coverage would be feasible throughout their territory. The joint solution will introduce the capability to proactively manage outages, manage wholesale power supply costs through peak management, and provide data for member-serving energy efficiency programs and applications.

This project is a joint effort between Tantalus, Itron, and General Pacific, one of the leading wholesale stocking distributors in the Pacific Northwest. IPL will utilize the newly released TUNet-enabled CENTRON® II electric meters for their deployment. This high-performance residential meter will deliver granular meter data to TUNet applications which will enable IPL to immediately utilize features such as interval meter reading, remote disconnect/reconnect, and power diversion management.

"Itron is excited to work with a utility that's in our backyard in the Inland Northwest. IPL will benefit from Itron's highly adaptable technology which is designed to help utilities more efficiently manage energy and water resources," said Lou Gust, Itron vice president of sales and marketing for electricity in North America. "Together with Tantalus, we are helping IPL realize the potential of smarter technologies and create a more resourceful world."

"IPL's service territory is diverse, but their need for highly real-time data driven operational applications is real," said Tammy Zucco, Tantalus Chief Marketing Officer. "Tantalus excels in both understanding the needs and challenges of public power cooperative and municipal utilities and delivering matching solutions to solve real challenges. We are dedicated to serving utility partners like IPL with the same high quality and cutting edge technologies that are often only easily accessible by larger utilities."

In 2011, Itron and Tantalus collaborated to offer a joint migration path to two-way AMI for municipal and cooperative utilities in North and Central America and the Caribbean. IPL joins the rapidly growing domestic and international Itron-Tantalus customer base which includes utilities like Appalachian Electric Cooperative (AEC), Piedmont Municipal Power Agency (PMPA) and Guyana Power & Light (GPL). The joint solution is designed to utilize existing infrastructure where possible to extend the value of those investments and to enable utilities to dynamically view and manage grid performance, proactively diagnose and resolve problems like outages, and automate many operational processes resulting in improved customer service.

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Potomac Edison Completes 2013 Equipment Upgrades Designed to Enhance Service Reliability

$50 Million Spent Last Year to Expand and Strengthen Electric System and Meet Growing Electric Demand in the Region

Potomac Edison, a subsidiary of FirstEnergy Corp. (NYSE: FE), has completed scheduled reliability projects for 2013 designed to further enhance the electrical system and reliability in its Western Maryland and Eastern Panhandle of West Virginia service areas. Major projects included transmission improvements, completion of new distribution circuits, replacement of underground cables, inspection and replacement of utility poles and ongoing vegetation management programs.

Potomac Edison's 2013 enhancements have both localized and widespread system benefits to customers throughout the service area. Upgrades to the distribution system include installation of new wire, cables and fuses to enhance service reliability. The company also completed transmission expansions and enhancements intended to increase the capacity and robustness of Potomac Edison's high-voltage transmission system. The work is part of Potomac Edison's overall $50 million investment in 2013 designed to help improve service reliability.

"These infrastructure investments are designed to help maintain our system on a day-to-day basis to benefit Potomac Edison customers now while helping to prepare our system for future load growth," said James A. Sears, Jr., president of FirstEnergy's Maryland Operations. "When combined with similar investments we've made in recent years, it's part of our ongoing effort to enhance the reliability of our system to benefit our customers."

Highlights of the Potomac Edison reliability work completed in 2013 include:

- The $5.3 million reconstruction of a transmission line to help maintain reliable electric service for more than 65,000 customers in Carroll, Frederick and Montgomery counties in Maryland.
- Completing $4.6 million in substation improvements to help enhance service reliability in Frederick County, Md.
- Replacing equipment at Ridgeley Substation in Ridgeley, W. Va. to help ensure reliability for 13,000 customers in Allegany County, Md.
- Completing vegetation management work along nearly 2,900 miles of distribution and transmission lines at a cost of about $23 million.
- Upgrading 90 distribution circuits at a cost of $1.5 million to help enhance the electrical system and reliability for 65,000 customers in Maryland and West Virginia.
- Replacing underground distribution cables at a cost of more than $2.5 million in Hagerstown, Frederick, Damascus and Mt. Airy, Md., and Wardensville, W. Va.
- Work to divide large distribution circuits in Germantown and Urbana, Md., and Martinsburg, W. Va., to prepare for load expansion in high-growth areas and to help reduce outage frequency.
- Inspection of 37,000 utility poles and replacement of 250 poles at a cost of about $2 million.

Potomac Edison serves about 250,000 customers in seven Maryland counties and 132,000 customers in the Eastern Panhandle of West Virginia. Follow Potomac Edison on Twitter.

New York State Smart Grid Consortium Applauds Governor Cuomo's Vision for Community-Based Energy Solutions

The New York State Smart Grid Consortium (NYSSGC), a public-private partnership devoted to statewide implementation of the smart grid, praised Governor Andrew Cuomo for his vision on energy issues as outlined during today's (Jan. 8) State of the State speech in Albany. The NYSSGC and its members also applauded the Governor for his foresight in recognizing the importance and urgency in upgrading New York's electric grid and his leadership in advancing community-based microgrid solutions, which he unveiled with Vice President Joe Biden yesterday (Jan.7) as part of his 'Reimagining New York for a New Reality' strategy.

'Community grids protect people, businesses and infrastructure from the devastation of extreme weather and from extended power outages as were experienced following Superstorm Sandy, Hurricane Irene and Tropical Storm Lee,' said James T. Gallagher, Executive Director, New York State Smart Grid Consortium. 'The power grid of the future will provide more flexibility and choices for consumers and Governor Cuomo's NYPrize competition will be a catalyst for the grid's transformation.

The community-based microgrid approach is an innovative way to address a number of challenges and new developments facing New York's electrical infrastructure. Ultimately, it can be the means to increase reliability and give local communities more control of their energy systems while also allowing for the adoption of clean and efficient distributed energy sources such as solar or combined heat and power. It can also be the conduit for integration of an electric vehicle charging infrastructure, which has been another priority of the Cuomo Administration.

'The leadership of the Governor and his Chairman of Energy and Finance, Richard Kauffman, have been essential in developing a coherent pathway to efficiently and effectively build a 21st century smart electric grid from which all New Yorkers can reap the benefits,' added NYSSGC Chairman Robert B. Catell, who was in attendance at the Governor's State of the State.

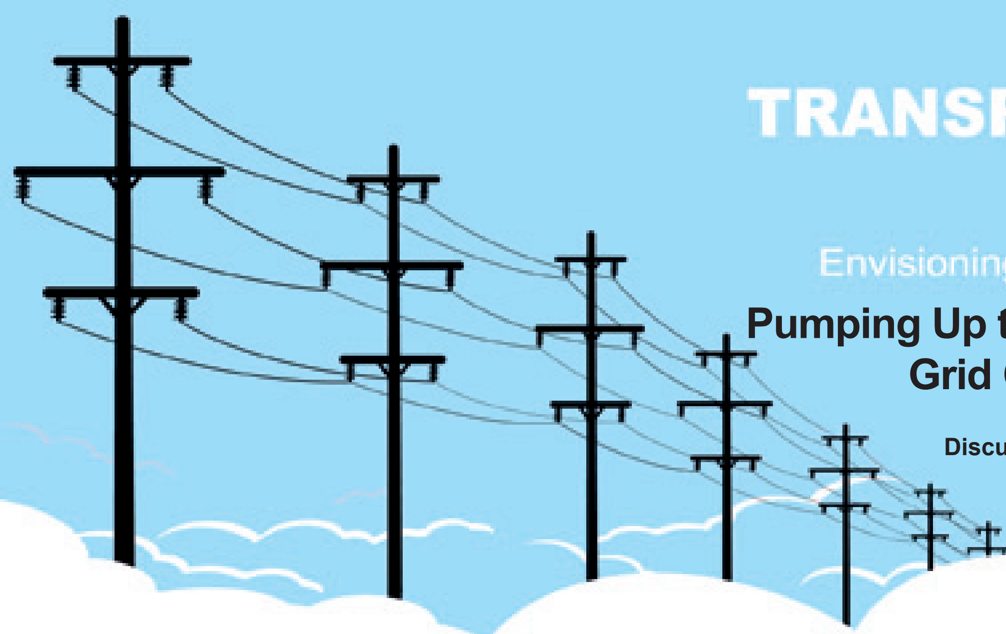
Utility Spending on Smart Grid IT Systems Will Reach Nearly $20 Billion by 2022, Forecasts Navigant Research

The expectations for the many smart grid projects that have rolled out over the last few years are high. Yet, without intelligence and systems that know what to do with the data generated, the smart grid is just a more expensive version of the conventional grid. Information technology (IT) - through software solutions that are integrated across a utility's operational silos - makes the smart grid 'smart.' A bewildering array of utility IT solutions has emerged to meet these needs, but the challenge to acquire, integrate, and maintain these systems is formidable. Click to tweet: According to a new report from Navigant Research, utility spending on IT systems for the smart grid will grow from $8.5 billion in 2013 to $19.7 billion in 2022.

'The acquisition and integration of new and upgraded IT systems for electric utilities presents one of the greatest challenges faced by the industry today' but also an unprecedented opportunity,' says Richelle Elberg, senior research analyst with Navigant Research. 'Utilities can now have not only granular data about the status of their network components and customers, but also the ability to quickly and appropriately react to that data. Utilities will need to carefully choose which systems they implement, in what order, and ensure that there is seamless integration across departments and field crews in order to maximize this potential.

One challenge for this market is the sheer volume of data that new sensing and automation devices will deliver. That information must be stored and analyzed, as well as shared with a variety of IT systems. This is an expensive proposition - good for vendors, but less so for utilities, according to the report. Utilities may also be challenged to obtain approval from regulators that are reluctant to approve large investments with limited real-world examples of measurable benefits to ratepayers.

The report, 'Smart Grid IT Systems,' provides a comprehensive overview of the global market for utility smart grid IT systems. The study discusses the potential benefits and challenges to utilities deploying new IT systems and describes a dozen major utility IT applications. Global market forecasts for utility smart grid IT systems, segmented by category (software purchases and upgrades, software maintenance fees, services, and SaaS), application, and region, extend through 2022. The report also provides in-depth profiles of numerous vendors and systems integrators involved in the utility smart grid IT space. An Executive Summary of the report is available for free download on the Navigant Research website.



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Pumping Up the Volume on Smart Grid Customer Education

SmartMark CEO, Juliet Shavit, Discusses the Benefits of Standardizing Smart Grid Customer Education

Juliet Shavit has never been shy about the importance of investing in Smart Grid customer education. Electric Energy T&D magazine sits down with Juliet to talk about her latest ambition – standardizing a framework for Smart Grid customer education.

EET&D: So what have you been up to?

Shavit: I and my organization have been hard at work developing a framework for Smart Grid customer education to help the energy and utility industry better focus on the importance of customer engagement and define its place in the Smart Grid business case and larger deployment roadmap.

Since this framework is missing right now in the industry, many utilities and stakeholders are approaching the topic in many different ways. It is causing some level of confusion across the industry, particularly as utilities seek validation or cost recovery for their efforts.

EET&D: What is the purpose of standardizing customer education?

Shavit: Despite owning a communications company, I have spent most of my professional career working with engineers and technology companies; specifically network and IT communications professionals. They tend to regard standards as an important way for implementing new technologies, particularly when it comes to technology integration. Standards help different companies and parties talk to each other. They also ensure a level of quality and security, which is often necessary. Sometimes these standards are dictated by government, sometimes by industry and sometimes by companies seeking out new technologies in their RFPs. Standards, or sometimes less rigid frameworks, are meant to keep parties of disparate backgrounds on the same page.

I can't think of a better reason for rolling out a universal framework for Smart Grid customer education than bridging the communications gap between utilities IT and marketing and customer care departments. Helping to identify needs, requirements and metrics on all sides of the Smart Grid table will inevitably lead to smoother Smart Grid deployments.

EET&D: When you say standards, I think many in our industry cringe. What are people afraid of?

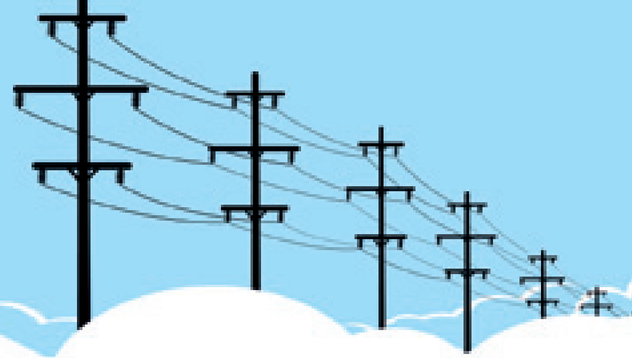
Shavit: I am not sure I would define our education model, published this month, a standard as much as a framework. Although both are ultimately designed to aid in the roll out of Smart Grid communications and programs internally within utilities, and externally between the utility and its multiple stakeholders. It is more of a standardized approach to customer education.

As for the initial negative reaction to standards, utilities may initially shy away from standards, particularly since there are so many influences that guide the technology decision making progress. But, in the case of network security and reliability, utilities are the first to say that there is a level of quality they will not go below, and are the first to accommodate the highest standards in these areas.

EET&D: How do you define model? What are the key components of the Smart Grid Customer Education model?

Shavit: The model is meant to be a framework developed from industry best practices. It is an 'instructions manual' that offers utilities a recipe for rolling out Smart Grid customer education that is measurable and easy to discuss both internally and to external stakeholders.

The model is broken down into phases of education that parallel phases of deployment – whether it is AMI deployment or a smart grid related program deployment. The phases include Pre-deployment (Inform customers), Deployment (Educate), Activation of Benefits (Engage), and Program rollouts (Impact Behavior Change). Each phase has its own unique requirements and metrics associated with it. It is the culmination and analysis of the metrics in all four phases that result in hopefully a success story.



EET&D: Have you seen any changes in our industry in regards to customer education?

Shavit: I am excited by the industry's recent attention to the topic. The work that the Smart Grid Consumer Collaborative does is excellent and they have brought a great deal of attention to the topic of customer engagement. Also, each year at our Smart Grid Customer Education Symposium events, we bring the industry together to try and really listen to what the industry is doing and learn from each other.

This increased focus on sharing and collaboration is awesome. The U.S. DOE's decision to form a working group was a great way to bring utilities together to talk and share in the development of best practice recommendations to the industry.

Since I personally aid in the roll outs of multiple Smart Grid programs, I can tell you I am always on the phone talking to utilities about innovative programs that they can roll out using industry best practices. I always start in a test environment, but often great ideas from other utilities really add value to programs I am working on. Also, regulators and outside stakeholders really appreciate when we talk about how we are implementing a program that has been successful elsewhere.

EET&D: What can we expect from our industry in the coming months?

Shavit: I hope that we will continue to see more increased collaboration and sharing of best practices. I also think we will see regulators and stakeholders spending a bit more time in understanding what to look for in their local utilities. We recently opened an office in Nashville, and I am working with one utility locally that is redefining innovation and openness for me, so I expect we'll see some great deployments there in the months to come!

EET&D: We can't thank you enough Juliet for spending some time with us. It's good to know people and companies like yours realize the absolute importance the Smart Grid will have on the future of the world. Teaching about it in depth by developing a framework for learning impacts not only the corner office, engineering and IT departments, but also the control room and field crews. Operatives and consumers alike will all be beneficiaries of this bold move from your group.

GREEN OVATIONS

Innovations in Green Technologies

Innovative Ontario Businesses are bringing Reliability and Sustainability to the Grid

Commercial, industrial and institutional facilities are taking part in a grid initiative that will help keep Ontario's electricity generation and demand in balance

By Malcolm Metcalfe, LVO, P. Eng

With the launch of a 'first-of-its kind' electricity grid initiative in Ontario, local businesses from various industries across the province are playing an innovative role in the electricity sector. From hospitals, universities, and large retailers to cold storage facilities and wastewater treatment plants, this network of forward-thinking organizations is responding to the real-time needs of the provincial power system.

What Role Do These Facilities Have in Supporting Ontario's Grid?

As major electricity users, these industries operate large electrical equipment (or loads) with extensive and sophisticated operating processes. These loads have hidden flexibility in how and when they operate – and it is through this operational flexibility that these local organizations are contributing to the reliability of Ontario's grid. Utilizing equipment that already exists within the provincial power system to help balance the grid also adds to its sustainability.

"This project represents a big step forward for Ontario's electricity sector," said Bruce Campbell, President and CEO of Ontario's Independent Electricity System Operator (IESO) at the launch of the new initiative at Toronto's Sunnybrook Health Sciences Centre. "Every day in our control room, we see the efforts consumers make to reduce their energy use at peaks, which in turn strengthens reliability. Now we are taking demand response to a new level. We are looking to major power consumers to provide a highly sophisticated – and critical – component of grid reliability."

But large electricity customers aren't just contributing to a reliable and greener grid – they are benefitting too. Participation benefits include a new revenue stream, a cost-free implementation utilizing existing energy-consuming equipment, a positive impact on the environment and the community and real-time usage data.

A First for Ontario

This initiative was launched October 2013 with an event at Sunnybrook Health Sciences Centre, one of the inaugural participants. For the first time, Ontario's large electricity users can take part in this regulation service, an ancillary service that maintains power system reliability by balancing the electricity on the grid in real time, matching total power generation with total power consumed on a second-by-second basis.

This is an increasingly important service for utilities and system operators as more variable generating resources come online. The programme responds in real time to address and correct electric power supply and demand imbalances. Traditionally, this service was performed by generators, which would ramp up and down to match continuous demand changes.

In 2012, the IESO launched a request-for-proposal that would explore alternative providers of regulation service. A Smart Grid technology company was selected based on their extensive experience with commercial, industrial and institutional loads and their real-time, intelligent load management platform.

Today, various high-profile and leading edge Ontario organizations are taking part in the Grid Balance initiative, using large electrical equipment that they've already invested in to deliver flexibility back to the provincial power system. Inaugural participants include McMaster University, Sunnybrook Health Sciences Centre, Confederation Freezers, Collingwood Public Utilities, Atlantic Packaging and Walmart.

"Engaging Ontario businesses as active participants in balancing the grid is an important step towards modernizing the province's power system," said Ron Dizy, President and CEO of Enbal Power Networks. "We are proud to see the Ontario Grid Balance network make its debut with some of the province's most forward-thinking organizations."

How are Local Businesses Helping Balance the Grid?

These organizations that are helping to keep Ontario's power system in balance are major electricity users that have already invested in large electrical equipment, have a minimum peak demand of 1,500 kW and device automation and control. Whether the equipment is working to keep a comfortable temperature in their buildings, refrigerate temperature-sensitive products or treat wastewater, these types of large electrical loads can be used for a secondary purpose – without affecting their primary duties and processes.

Universities and other large educational institutions have a responsibility to maintain comfortable temperatures throughout all buildings within their vast campuses. McMaster University, one of Canada's oldest and most prestigious public research universities, utilizes their extensive HVAC (heating, ventilation and air conditioning) system to keep their campus at the ideal temperature for students and teachers. The university is a big believer in innovative technology that enhances the sustainability of their campus and community; the institution is committed to reducing its energy consumption, implementing energy initiatives and promoting energy efficiency.

The chillers in McMaster University's large-scale HVAC system have the operational flexibility needed for this initiative. After working closely with engineers to determine the operating parameters necessary to keep the system running smoothly, five chillers with a 16,000 ton cooling capacity have been connected to the network to help keep Ontario's electricity generation and demand in balance and maintain overall system reliability.

"Connecting to ENBALA's platform was a seamless process, and the Grid Balance initiative is providing our university with an excellent cost-savings opportunity that helps the environment and the provincial electricity grid – using the equipment we've already invested in," said Joe Emberson, Director of Energy Management and Utilities at McMaster University.

Hospitals and other large healthcare institutions can also take advantage of their existing HVAC system and the flexibility it has hidden within its operating process. Sunnybrook Health Sciences Centre, host of the Grid Balance initiative launch event and a state-of-the-art teaching hospital, is a leader in green innovation, winning numerous awards for its environmental stewardship. The hospital has connected five chillers within their central chiller plant to help balance Ontario's grid and reduce greenhouse gas emissions produced by traditional generators. While participating in this grid balance initiative, Sunnybrook's chillers remain within predetermined operating parameters necessary to keep the hospital at a comfortable temperature. Patient care and comfort come first for Sunnybrook.

These two organizations provide examples of how HVAC systems within institutions can boost grid reliability.

What about commercial and industrial companies?

Confederation Freezers is a refrigerated warehousing and distribution company with a 20 million cubic foot operation over four Ontario locations. Cold storage facilities are perfect for this type of initiative because of their sophisticated refrigeration systems, which use a number of flexible energy-consuming assets like compressors and pumps. Five of Confederation Freezers' ammonia compressors are providing operational flexibility to Ontario's grid, while remaining within set temperature parameters and maintaining the quality of their temperature-sensitive products. A new form of revenue was an attractive aspect of Grid Balance for Confederation Freezers, according to Fred Leonenko, Chief Engineer. "[Grid Balance is] a way for the compressor room to actually generate revenue, rather than being a major expense at our facility," he stated. An additional revenue stream is an added bonus to participation in the initiative, and can be applied against high electricity bills or any other day-to-day operating costs.

The Grid Balance initiative is operated by ENBALA's real-time intelligent load management platform.

This is Only the Beginning of the Demand Side's Potential

Commercial, industrial and institutional organizations are a valuable resource for Ontario's grid. Keeping electricity generation and demand in balance is just the beginning. Through innovative technology, large electricity customers can step up and play a more active role in grid management, generator optimization, integrating renewable energy and more – becoming a major power player in Ontario's electricity sector and beyond.

About the Author

Malcolm Metcalfe, LVO, P. Eng, is a veteran of the high growth technology industry and an expert on the evolution of the power system, with over 40 years of experience in energy and related systems. Mr. Metcalfe is a founder and Chief Technology Officer at ENBALA Power Networks. A graduate of the University of British Columbia, he holds a BASc and MASc in Electrical Engineering, with a specialty in Power Systems.

From Research to Action

Information and Communication Technology (ICT) – a Key Enabler for the Future Power System

By Matt Wakefield, Director, Information and Communication Technology Electric Power Research Institute

Electric Energy T&D is pleased to introduce the latest member of our lineup of regular editorial features. Through the eyes of the Electric Power Research Institute (EPRI) From Research to Action takes an inside look at the hottest, most technical, and advanced aspects of electric energy T&D.

There are many dynamics affecting how the electric grid is operated in normal conditions as well as during significant events such as major storms. The factors affecting the dynamics include the retirement of coal generation, increasing natural gas generation, increased adoption of solar photovoltaics (PV) and new loads like electric vehicles (EV) – all having an impact on where electricity is generated and where it is delivered. As we consider all of these factors, one thing is clear; the flexibility of the grid is becoming increasingly important. Flexibility is needed to support distributed energy resources, new loads and changing generation mix to enhance reliability and the customer experience.

Utilities are finding that a key enabler of a flexible grid is the ability to apply information and communication technology (ICT) to electric transmission and distribution systems as well as end-use loads and resources.

A number of information and communication technologies enable utilities to achieve greater flexibity. These include deployment of communication technologies to field devices, emerging standards and protocols, cyber security measures that address threats to an interconnected grid, data analytics, and enterprise architecture applied to electric grid operation technology (OT). Each of these ICT areas can be applied to address industry needs such as wide area situational awareness, operations and planning and mobility to accommodate increased numbers of distributed energy resources on the distribution system as well as to improve operations and reduce system restoration times during major events.

Bennett Gaines, Senior VP and CIO at FirstEnergy is the first Chairman of the Electric Power Research Institute's (EPRI) new ICT Council, and enthusiastically embraces utility research, development, and application of information and communication technologies stating, "There is a heightened appreciation for IT knowledge, tools, and techniques used by electric utility operational groups. This growing dependency on information and communication technology is resulting in stronger intra-department relationships which are key to continue to provide our customers safe and reliable service that responsibly leverages emerging technologies."

For information and communication technologies to have the most impact, they must be considered foundational in the evolution of utility systems, both from a technical and organizational perspective. Many EPRI member utilities agree, and are participating in programs to research, develop and demonstrate these technologies. Following are highlights of utility views, progress, and research needs.

IT/OT Convergence

Information technology (IT) is increasingly being applied to electric grid operations--an observation confirmed by a 2012 EPRI survey of utility chief information officers (CIO's). We learned that convergence of IT and OT is underway at many utilities, although pace and approach differ. How utilities are managing internal IT/OT convergence can be distilled into three main themes: re-engagement in IT/OT convergence discussions, partial re-organization, and, for some, a complete re-organization. Regardless of the approach, utilities are benefiting from advances in ICT by aligning technology and organizational structures. (For more details on CIO's views of IT/OT convergence and technology change see EPRI's publicly available *Utility Chief Information Officer (CIO) Outlook Report).* [1]

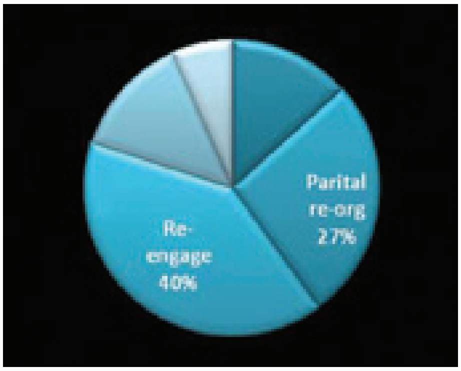


Fig. 1 CIO Responses to IT and OT Alignment

The prominent use of Internet Protocols (IP) around the world is changing the way utilities look at their communication systems. Cisco's Visual Network Index (VNI)[2] and its forecast of global IP traffic indicates that by 2017 there will be 19 billion IP connected devices globally. If this forecast proves correct, there will be up to three times as many IP connected devices as people in the world, a huge increase from 12 billion in 2012. In that same time frame, traffic from wireless and mobile devices will exceed traffic from wired devices.

From Research to Action

EPRI's research assessing utility field area networks (FAN's) is paralleling global trends. We see a growing interest in pursuing unified IP-based networks in a variety of scenarios (public, private, licensed, unlicensed) for communications to field devices and work crews. Interest has been spurred because the business case justifying the combination of multiple, disparate communication systems into a single system is becoming closer to reality as the costs continue to drop, availability of products continues to increase, and network performance continues to improve.

That doesn't mean IP-based communications is without risk. As more and more devices on the grid become connected, the cyber attack surface area is becoming larger and a 'Defense in Breadth' approach is required. This approach relies on overlapping protective measures so that if one measure fails, it will be caught by another. As more remote devices are connected to the grid, it is becoming increasingly important to have architectures, tools, and procedures that provide end-to-end security. Technology needs to be deployed in such a way that if it is compromised the full risk is known and can be mitigated. In addition, other complexities such as remote employees, field crew with mobile devices and BYOD (bring your own device) initiatives may pose similar risks and need to be considered.

Legacy Equipment

Advances in communication technology are accelerating development of new and exciting business approaches for utilities, but this is not without challenges. Utility assets (transformers, meters, capacitor banks, etc) have a lifespan that may be decades long, while emerging communication technologies and hardware may have an evolution lifespan of 18 to 36 months before it could be replaced by higher performance products. Furthermore, the proliferation of IP-based communications doesn't mean everything should and will be IP-based. These factors create uncertainty about investment, making development of a modular communication architecture that preserves the useful life of legacy equipment, while enabling deployment of new communication technologies, is increasingly important. One example of a modular communication approach is the Consumer Electronics Association (CEA) new standard for a modular communication interface for demand response – CEA-2045. This standard defines a port/plug that enables an off-the-shelf consumer product that is compatible with multiple utility demand response systems and enables a customer-installable plug-in communication module.

Fig. 2 CEA-2045 Modular Communication Interface

This standard is unique in that it makes it practical for manufacturers to make their mainstream products (water heaters, clothes dryers, etc) 'demand-response ready.' A physical connector (CEA-2045 compliant) that is compatible with utility demand response communication systems can be available through normal retail supply channels – independent of the communication technology or architecture. With this architecture, an appliance with a useful life of even 20 to 30 years may function in utility demand response programs without risk of obsolescence due to evolving communication systems. At EPRI, we are demonstrating this standard with numerous utilities, and exploring other applications of a modular architecture that may be beneficial for transmission and distribution equipment.

Improving Reliability

ICT is being used more and more to improve reliability of the grid. Data analytics can predict outages or equipment failures and communication networks can automatically indicate when and where an outage has occurred. After a major storm, assessing the damage and improving tools to communicate restoration activities from field crews may significantly reduce recovery times. For example, in major events, it may be difficult to dispatch crews to assess physical damage due to downed trees or icy conditions. Any efforts or technology that can speed up the damage assessment process could reduce restoration times by hours or even days.

The UAV restoration solution requires that a number of technologies create a system that communicates data back to the utility, analyzes data for image recognition, utilizes standardized messages compatible with utility back-office systems using standards like the Common Information Model (CIM), and helps create work orders. Variations of assessing images from UAV's could exist if access to high resolution satellite images was granted, but similar data analytics research is required to perform image processing.

Fig.3 EPRI Testing Unmanned Aerial Vehicles

Another tactic for restoration is arming field crews with tablets that have GPS sensors and cameras that allow field personnel to document damage and create work orders. This will mean that by developing standards for doing this in a common way can enhance field crew performance because in major storms, mutual assistance crews from other parts of the country could bring their own devices and will already be familiar with the interfaces and process and require minimal training.

Unmanned aerial vehicles (UAV's) that can rapidly assess damage are an emerging technology option to aid restoration efforts. A number of research questions are associated with UAV's on their own, but from a utility ICT perspective, a major research question is the performance of image/video recognition that automatically assesses photos and videos. Another issue is having standards to communicate data into utility systems, documenting the damage and automatically creating work orders to dispatch equipment and crew more efficiently.

Fig. 4 Augmented Reality Applications on Tablets for Field Crews

Data Analytics

How to derive information and knowledge from data collected and communicated with new technology is an essential research question for utilities. The following list of findings and interesting quotes from utilities on data analytics offers a view of the state of the art. These are excerpted from the EPRI November 2013 Data Analytics Newsletter[3]

1. There continues to be an underlying concern that there is more data being collected than there is value derived from that data. Getting value out of various data sources is therefore a timely and important objective regarding data analytics collaboration across the electric power industry.
2. Integration of disparate data sets and getting data out of silos is a major undertaking that has not been well resolved by the industry just yet. This is not unexpected, as most data collection has traditionally been departmentally funded and as such that department tends to own and protect its data.
3. Many of the data analytics efforts outside of smart meters are at the pilot stage and not fully deployed. While we don't have an exact number, the majority of the value from analytics efforts to date is centered on AMI data.
4. Some utilities are making a concerted effort to reinvent the role and integrations of their IT groups. Some have brought in IT management with experience in the banking and data center industries where 'big-secure-data' and 'streaming analytics' is not a new concept. They bring perspectives on big data and understand the importance of data governance.

5. There continue to be hurdles with getting the (analytics area of the electric service business) funded. This is a twofold issue, first because many analytics projects and efforts to date involve point solutions for point problems, and secondly because of staffing and budget constraints.
6. Many utilities purport their programs and analytics capabilities to be much further along than they really are. This space is changing quickly but in general, a lot of the analytics are in the pilot demo stages.
7. Some utilities are successfully implementing secure cloud solutions for data cost management. These are again, point solutions and don't yet traverse the enterprise.
8. Many utilities are grappling with the questions around ownership of analytics and applications. Most clearly believe this ownership should be across business units and not residing in IT for example. IT should own and maintain the platforms, tools, security, etc. but the corporate buy in and ownership is an area where best practices for utility analytics must be vetted.
9. Data Governance – Many believe this should be a corporate function and not an IT function so that any point solutions can ultimately get mapped to the corporate smart grid business plans and feed/support the longer range (Smart Grid 2020) vision.
10. Value Streams – At the end of the day, every data set and every data analytics project must stand on its own, based on the value it brings to the enterprise.

This list, as well as the topics mentioned in this article, touch on just a few areas where ICTs are being applied to improve performance of the grid. Moving forward, the continued coordination between IT and OT efforts will be a key enabler for a flexible power system.

References

[1] Utility Chief Information Officer (CIO) Outlook – 2012, EPRI, Palo Alto CA: 2013. Product number 3002000085

[2] Cisco Visual Networking Index (VNI): Forecast and Methodology 2012-2017

[3] EPRI Data Analytic Applications Newsletter (DMD and TMD Demonstrations). Available at *www.smartgrid.epri.com*

About the author

Matt Wakefield is Director of Information and Communications Technologies research at the Electric Power Research Institute (EPRI). His responsibilities include overseeing research in smart grid technologies, data analytics and cyber security. The focus of his research area is to further the development of a modernized grid with a focus on utilizing emerging information and communication technologies that can be applied to the electric grid infrastructure and how to make the grid more resilient from cyber security threats.

Wakefield started his career in 1986 in the United States Navy serving as a Nuclear Power Plant Reactor Operator and Engineering Supervisor in the Submarine Fleet and specializing in electronic instrumentation and controls.

Wakefield then joined Wisconsin Public Service Corp. (WPS) in the Instrumentation and Control Group of the Kewaunee Nuclear Plant before becoming Manager of the Applied Technology group at Integrys Energy Group, the holding company of WPS. At Integrys, he focused on developing and applying information and communication technologies related to low-cost, real-time energy-related information transfer between control centers, generators, markets, and consumers. This team developed a number of innovative solutions including DENet® and eMiner® that utilized emerging open-source software and low-cost embedded hardware while leveraging the Internet for a virtually free communication infrastructure.

Considerations and Preparations for Evolving Utilities' Networks

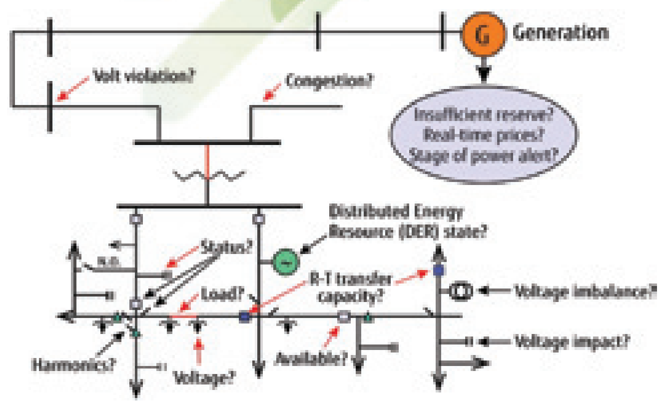
By John Chowdhury

Utilities' transmission and distribution professionals and their peers in information technology organizations are faced with numerous challenges in today's environment. End customers and regulators want a more efficient and reliable grid; the current grid assets are aging; and new demands including: higher plug loads, distributed generation, electric vehicle integration and challenging environmental conditions are being placed on the existing grid's automation systems. Utilities must pursue grid modernization, including implementing automation solutions, for reliability and to meet these growing demands. This must be done while at the same time extending the life of existing grid assets and with little to no increase in operating budgets. This is no small task.

The challenge, and the opportunity, can best be described in terms of assets that need to be evaluated, followed by development of a plan utilizing advanced sensor technology and communications systems. The result can be an information-rich grid that generates positive returns on investment in terms of operating costs, power delivery efficiency, and grid reliability.

Grid automation plays a vital role in that these systems make it possible to isolate a fault and reconfigure a distribution system without requiring manual switching. With advanced distribution automation, a utility can isolate a fault and reconfigure a distribution system in a short time period (typically less than two minutes) without human intervention. Due in large part to advances in automation technology over the last decade, including enhancements in relays, reclosers, communications systems, and software, utilities can make step-function improvements in reliability at appropriate times and with a reasonable cost.

To get a feel for just how effective automation is, consider that in a well-maintained distribution system with no automation, the average customer experiences 120 minutes of outage each year. Worse yet, the further a customer is from an available energy source, the longer it takes to restore service, resulting in significantly different levels of reliability based on location. The following diagram illustrates the distribution grid with key automation information requirements.



Communication systems are put in place to capture and relay data points to the control center. This information will help identify problem areas for faster resolution.

By employing distribution automation then, a utility can cost-effectively reduce outage time and improve response. The considerations and series of steps described below assume that a utility is in its initial stage of approaching distribution automation as a means to improve system reliability. It also illustrates the design concept required to achieve varying levels of system reliability over a period of time.

Measurable Benefits

Advanced information technology, databases, communication and controls are increasingly making a vast array of new grid distribution applications possible. To the extent they are economic and/or promote other policy goals, utilities have the ability to build these technologies into their distribution systems and transform their grid, achieving advances in:

- **Reliability:** With higher-quality delivery, less-frequent outages, and dramatically faster restoration when an outage does occur
- **Security:** By increasing the use of distributed generation as a part of total generation
- **Economics:** With optimal peak and average energy prices set by region; losses due to power transmission congestion, interruptions or quality degradation minimized; resulting in a lower overall total cost of energy delivered
- **Efficiency:** Occurs through a lower level of system electrical losses, a lower peak-to-average load ratio and lower number (< 10 percent) of lines congested for a duration of time
- **Environmental stewardship:** Achieving a higher ratio of renewable generation to total generation and reducing emissions per kilowatt-hour delivered
- **Safety:** Significant reduction in injuries and deaths to workers and the general public

Having described these benefits, it's also important to keep in mind that different types of distribution networks/systems (e.g. urban, suburban, rural, special use) have different characteristics and each will return more or less benefit through automation. Said another way, automation applications that provide positive value in one part of the overall system may not be applicable to, or deliver positive economics in, other parts of the system. Given that, it's wise to work with a partner that understands these differences and can offer appropriate guidance.

Energy and Information Flows

Traditional grids were designed to perform one function – distribute electrical energy to end-users. But increasingly, distribution systems are delivering electrical energy and information between participants, system operators, and system components. As implementations of demand response and other Distributed Energy Resources (DER) applications find their way into grid architectures, we see the lines between electricity supplier and consumer blur; many of the participants will actually assume both roles. In this scenario, the exchange of information is multi-directional and will facilitate smarter system operations, and potentially enable decisions on whether to act as a 'supplier' or 'user' of electrical energy based on dynamic (rather than static) pricing.

For this sophisticated exchange of electricity and information to be possible, the automated grid relies on a communications architecture that supports network component monitoring and system control functionality. Ideally, these communications architectures will be designed on open systems so that new technologies and components from multiple vendors can be easily integrated as required. The automated grid also relies on new electrical architectures and protection systems that enable an interoperable network of components.

Taken together, the communications architecture, protection systems and interoperable components comprise the automated distribution system at the heart of grid transformation.

The Information/Communications Infrastructure

In a grid transformation, the link between customers, smart devices on the grid, and system operators lies in the communications infrastructure. As the complexity of these communications grows and the time-frame tolerated for information exchange decreases, the infrastructure must provide a higher-bandwidth and lower-latency. Also, as more critical functions are automated, the communications infrastructure must provide a heightened-level of security. And just as is true when defining the optimum energy infrastructure, the right communications infrastructure will be built on an open architecture and common protocols, enabling the interoperability of different devices from different vendors.

It is the communications infrastructure that enables many of the features grabbing headlines in the general media. Capabilities such as Advanced Metering Infrastructures (AMIs) catch the attention of the end-user. Sensing and monitoring devices, as well as intelligent applications, transmit valuable usage and management/control information that is viewable through secure consumer portals.

For the utility, a grid transformation delivers the same advantages as are enjoyed by the end-user, and then some. The utility will gain real-time state estimation and predictive capabilities (including fault simulation modeling). With this, it becomes possible to continuously assess the overall state of the distribution system and predict future conditions, providing the basis for system optimization. Advanced control systems allow the utility to optimize performance of the entire distribution system for efficiency, asset management, reliability, quality, and security. And last but certainly not least, load management and real-time pricing becomes a reality which allows the utility to optimize system performance, efficiency and profitability.

Getting There

While each individual utility that is considering a grid transformation project will have its own set of priorities, challenges and business dynamics, there are a few considerations that are universal to all. The design and development of any distributed automation communications architecture must consider:

1. Scalability
2. Reliability
3. Federation
4. Interoperability
5. Adaptability
6. Security

Scalability should be looked at through a long-range lens. For some utilities this will mean projecting-out five, ten or even more years. In so doing, it's important to consider what the future might hold across multiple variables. For example, look at population growth rates, review the applications that may require additional support and think about how many physical sites could be added to the network.

Reliability is nearly taken for granted by the general public. Of course utility professionals know better. Ensuring reliability means using robust technology with a proven ability to deal with failure gracefully. Any part of a distributed system can fail. Any grid transformation communications architecture must incorporate backup components and the ability to execute a seamless failover.

Federation is a particularly important idea in many grid transformation projects because multiple vendors' technologies are involved. When working for the benefit of the end-user customer, the vendors involved in the transformation will often agree as a group to support a set of standards. This federation greatly simplifies interfacing between end-user communication and control systems.

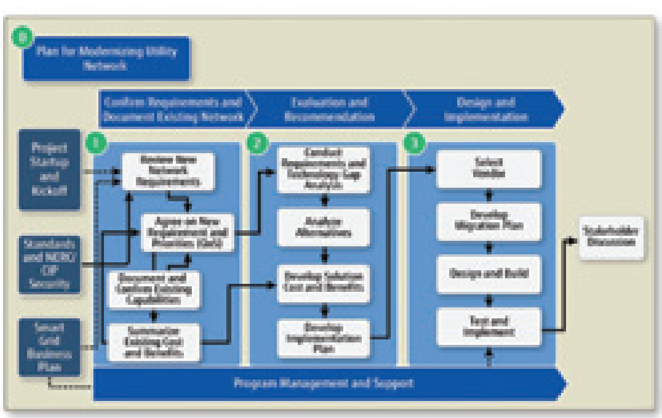
Interoperability is of course the goal of communications standards in general. However, when it comes to grid transformations, the sheer scope and variety of technologies in use places particular challenges on those responsible for making architectural decisions.

Adaptability also takes on a new importance in grid transformations. In contrast to traditional energy networks, where adaptation is almost always a manual, labor-intensive (and capital-intensive) process, successful grid transformations are those architected to adapt quickly and automatically, with as little human intervention as possible.

And last, but far from least in our list of important considerations, security. In a grid transformation, technology must be selected to support secure communications, safe from attack from within or outside a utility. A grid transformation presents unique security challenges. This is because distributed automation requires the integration of communications technologies across previously siloed (and firewalled) groups. Integration frequently occurs between SCADA and protection departments, automation departments into corporate IT domains and entire utilities into a deregulated market. With each level of integration comes the possibility of creating vulnerability in the network. Communications technologies that have proven to be most secure should be selected to minimize any security risks.

A Proven Methodology

Your partner in any grid transformation project should be one that's lived the experience on multiple occasions. Make sure there is a proven, repeatable methodology leading to a track record of success. Unfortunately, there is not enough space in one article to describe in detail the methodology I recommend, or the individual tasks and sub-tasks therein. However, the illustration below offers an overview, and I will summarize the major tasks that make-up this methodology.



A proven methodology results in a coordinated effort that provides both the necessary breadth and depth of analysis, alternative development and recommendations.

A Three-Step Approach

A successful grid transformation begins with a structured, logical progression of steps to devise a grid modernization plan. The three steps in this progression are broadly defined as:

1. Confirm Requirements and Document Existing Network
2. Evaluation and Recommendation
3. Design and Implementation

This structure will result in an objective, unbiased communications plan that utility management can use to support the need for modernization and integration of their communications capabilities. This plan is put into action with a methodology that lays-out a 'Road Map' of five task groups leading to a successful conclusion.

Let's talk about the first three of the five task groups. The first three tasks fall within what I call the project's discovery phase. The project team will conduct a kick-off meeting to ensure everyone understands the expected deliverables, players' roles and project schedule. After the kick-off meeting, there will be an assessment of current demand, utilization and future needs; followed by an assessment of the current infrastructure. The team will also conduct a legal and regulatory assessment. This is intended to yield a keen understanding of all such requirements (including licensing requirements) that need to be addressed in the implementation of the future network and services. The key outcome of these efforts will be the design of a network architecture that allows the communications network to accommodate all current and foreseeable needs with reliability, scalability and flexibility.

One of the initial tasks is to assess the network requirements for each communications application, e.g. voice, field data synchronization, retail field communications and others (see application types listed in leftmost column of chart shown at the top of the next page). It is important to understand these requirements to ensure sufficient bandwidth is allocated across the enterprise. In traditional network environments each application exists in a silo, with bandwidth allocated to each independently. But a grid transformation changes that approach. In a grid transformation, these applications will interact across the enterprise; therefore, there must be adequate bandwidth enterprise-wide.

Confirm Requirements and Document Existing Network → Evaluation and Recommendation → Design and Implementation

Application	Protocol	Latency	Bandwidth	Reliability	Scope	Security
Voice	G.729 and H.323 (VoIP)	~100s msec	<64 kbps	High	HR + P2P	NA
Field Data Synchronization	IP	100s msec	>100s kbps	Low	HR + P2P	High
Retail Field Communication	TCP/IP	NA	100 kbps	Medium	HR	Low
Fault/Emergency Communication	TCP/IP	1000s msec	100 kbps	Medium	HR	High
Works Management Communication	TCP/IP	1000s msec	100 kbps	Medium	HR	Medium
Aggregate	IP	<100s msec	100s–1000s kbps	High	HR + P2P	High

Determining the total communications requirements for Grid Automation is part of the project discovery phase.

At the conclusion of the discovery phase, the project team will conduct a gap analysis between the existing network and the new required communications infrastructure.

Based on the findings, the team will progress to Task 4. This task focuses on identification of alternative technologies available in the marketplace, and determination of the right technologies to meet current and future needs. The team will present to management a number of communications networking implementation options with associated schedules and costs.

The final task, Task 5, focuses on development and presentation of the detailed telecom strategy by the project team. The presentation should include:

- Summaries of the processes used and issues considered to develop the recommendation
- A strategic telecommunications plan for utilities consisting of:
  - Ultimate system plan in detailed block diagram format
  - Cost estimate to implement strategy
  - Recommended migration plan to new system
  - Discussion of recommended plan's compliance with utilities' business initiatives
  - Analysis of existing voice communications strategies, their fit with the recommended telecom strategy, and any recommended modifications
  - Estimates of manpower and equipment requirements to install operate and maintain the proposed solution, including training, test equipment, software, etc.
  - Brief synopsis of alternate strategies/solutions considered
- A high level strategic plan or 'Road Map' that brings together the transport, mobile, voice, and wireless data strategies under an overall strategy, describing any synergies and/or conflicts they may have.

Conclusion

The utilities industry is in the early stages of what will be a pronounced evolution. Consumer demand, changing energy usage patterns and the availability of advanced technologies are driving grid transformations. By using secure, non-proprietary, automated-healing technologies as the basis for these transformations, utilities are meeting current requirements while being equipped to meet changing needs in the future. But beyond the characteristics of the individual technologies, I believe having a proven methodology is critical. Taking a methodical approach to the transformation gives utilities maximum flexibility and control in how they proceed and is shown to result in the highest levels of success.

ABOUT THE AUTHOR

John Chowdhury is utility practice director at Fujitsu Network Communications, Inc. He develops unique network integration solutions, modernization programs and network operations offerings tailored to support utilities as they adapt their communications networks to meet new demands for scalability, reliability, standards, and security.

Recognized as a 'Who's Who in Energy' by the Dallas Business Journal, John has dedicated his 25-year consulting career to improving electric utility and telecom business performance. He has provided strategic business and technology guidance to international energy entities in the areas of: Smart Grid/AMI/distribution automation; business case development; customer relationship management; billing; and telecommunications/wireless networks.

Transmission and Distribution Engineers Hold the Keys to Optimal Integrated Resource Planning

By Scott Smith

The traditional notion of integrated resource planning (IRP) is rapidly changing within those utility contexts where distributed resources are playing a more prominent role. Traditionally, the transmission and distribution planners were not an integral part of the IRP process. As the industry transitions away from a pure vertically integrated business model and distributed renewable generation, smart grid technologies, electric vehicles and demand side services continue to expand, the location specific capabilities of power systems increasingly play a key role in the planning process.

In the context of integrated resource planning, forecasts typically look at energy and power requirements from 5 to 20 years into the future. A demand forecast is basic to analyzing how much new generation capacity may be needed, how transmission and distribution systems should be expanded, and in which customer groups or geographic areas these requirements will be concentrated. A good transmission and distribution planner must know how much power must be delivered, where and when it will be needed. He or she must be able to identify loading situations that require action, in advance of the lead time required for those actions, and be able to identify and evaluate alternatives in order to maximize the benefit(s) desired from its execution, such as:

- How long will this circuit configuration be an effective solution to the problem?
- Will we need another substation between this and the service area boundary, or is this new one it, forever?
- Do we need to allow for a second transformer in the new substation we will build in four years?
- Could demand side management (DSM) be an effective solution to the problem?

As the industry continues to transition toward distributed renewable resources and smart infrastructure, these questions will be increasingly difficult to answer with traditional 'top down' methods, and point to the need for a more granular circuit level analysis and a more central role for the transmission and distribution planners.

Today's resources must be positioned in the right locations in order to handle fluctuations in electric demand. For capital budgeting, an error in forecasting the amount, timing or location of future demand leads to a misallocation of the vital resources.

Furthermore, the economic recession has made it much more difficult to accurately predict distribution level load conditions, especially where mild weather has accompanied slower economic growth.

Over the past five years, several forward-thinking Investor and Publicly-Owned Utilities in North America are working to improve their IRP methodologies. Duke Energy, Pacific Gas & Electric, Fortis BC, Avista, and Nashville Electric Service and have partnered with Cincinnati based software company Integral Analytics (IA) to build the next generation of IRP software tools. What does this mean for T&D planning engineers?

The new software tools are part of IA's web-based forecasting system, LoadSEER. At its core, Spatial Electric Expansion & Risk, is a spatial load forecasting system designed specifically for T&D planners who face increasingly complex grid decisions caused by emerging micro-grid technologies, extreme weather events and new economic activity. The objective of the system is to statistically represent the geographic, economic and weather diversity across a Utility's service territory, and use that information to forecast circuit and bank level peak loads over the planning horizon. Planners are able to decompose system impacts using map layers superimposed on the spatial representation of the T&D infrastructure. As seen in Figure 1, load growth forecasts, distributed renewable generation, demand response, distributed intelligent systems and other demand or supply factors are spatially located relative to the existing capital infrastructure.

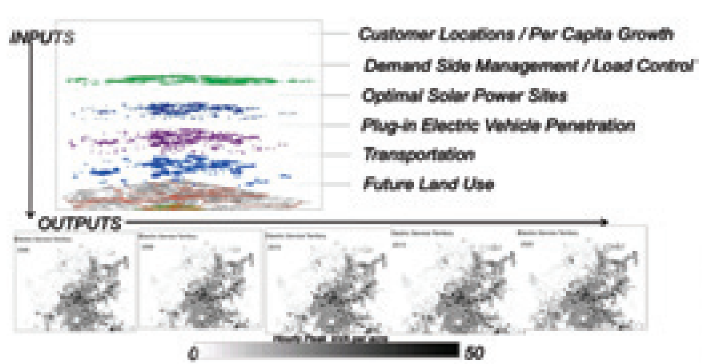


Figure 1 Map Layer Hierarchy

The powerful GIS mapping and load forecasting functionality uniquely blends short term econometric forecasting with long term geographic forecasting. This enables distribution planners to more accurately predict risks on their circuits due to local load growth and/or distributed generation (DG) changes, including electric vehicle adoption, increasing solar penetration, switching transfers, demand response and other factors. The core algorithm automatically models geographic and economic drivers, along with weather, to provide engineers with the most representative circuit by circuit forecast models. In some cases, one circuit might respond to Retail Sales, while another might be sensitive to Employment, Personal Income, Housing Starts, or various combinations. This process allows planners to analyze specific future scenarios such as transportation network expansion, suburban sprawl, urban redevelopment, new manufacturing and additional employment centers. The final forecast results can be leveraged to enhance an existing suite of planning tools, including direct exports to power flow analysis tools. Short and long term consistency is managed through a top down and bottoms up reconciliation process shown in Figure 2.

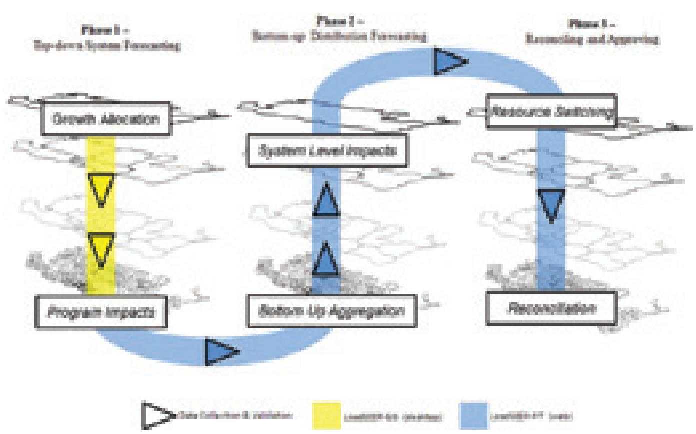


Figure 2 Top Down and Bottoms up Reconciliation

A major aspect is to insure both short and long term consistency with system level financial planning, by streamlining regulatory data requirements, creating more defensible long term substation forecasting methods, and streamlining various aspects of the decision and approval process. Moreover, the software enables a much more accurate methodology for calculating avoided marginal costs of grid asset deferrals for use in more intelligently targeting DG, Smart Grid programs, demand response and energy efficiency. The use of these tools is illustrated in the following example.

Case Study: Planning for Duke Energy's Virtual Power Plant

Integral analytics continues to work with forward looking utilities to develop smart, distributed resources. For example, the company worked with Duke Energy on its McAlpine Creek project, a 'virtual power plant' made up of grid electricity, solar power, large-scale energy storage, all linked together by a smart grid architecture that keeps power flowing and balanced. The initial phases of the project included solar arrays installed at the McAlpine substation in south Charlotte. Then households in the service territory received smart meters from the utility, with several participating in auto-DR residential energy management systems. The idea is to hook up air conditioners, heat pumps, water heaters, dryers and other appliances via wireless networks so they can be powered down or turned off to save energy and help the utility curb peak power demands.

Integral Analytics is tasked with getting all those things to work together. It makes software that can choreograph appliance demand across all these customers. By doing that, the system can reduce the total peak demand that the utility sees without actually curtailing demand. That is, it can get a lot of appliances and air conditioners and the like to respond to commands to turn their power use up or down slightly without a noticeable effect on the part of the homeowner.

Fine-tuning like this is made possible with the in-home devices feeding data to the utility, as well as sensors at the substation level. Working from those ends, Integral can do things like figure out which distribution feeder lines and transformers are under the most strain and turn down power demand from homes fed from them. At the same time, it can also take into account homeowner preferences for how they'd like their energy managed. For example, it can determine which customers said they're OK with having their air conditioners turned off versus those who want to keep them on.

That's a complicated task even when one is only dealing with relatively stable grid power. Adding solar panels that can see power output sag and soar depending on cloud cover overhead only adds to the challenge. It's a similar challenge facing utilities across the country as they seek to incorporate growing amounts of intermittent renewable power into their transmission and distribution grids.

The impact on the transmission and distribution system is modeled using a spatial resource planning model using the following eight step process:

1. Run the growth plan through LoadSEER
2. Identify asset/planning area capacity surplus and deficiencies
3. Enter planned deficiencies mitigation projects
4. Identify candidate T&D project deferral opportunities
5. Determine the needed DSM savings to defer the T&D capital project
6. Design an appropriate DSM project
7. Calculate the avoided capacity and energy cost
8. Evaluate cost effectiveness

The initial growth plan identifies specific circuits, transformers, substations and other T&D assets in need of expansion. For the region of study, several areas noted in red as shown in Figure 3 are in need a capital expansion. Every distribution circuit has a geographically defined polygon service boundary based on the customers served, and is color coded based on the forecasted load versus capacity. The map identifies where and what capacity is needed.

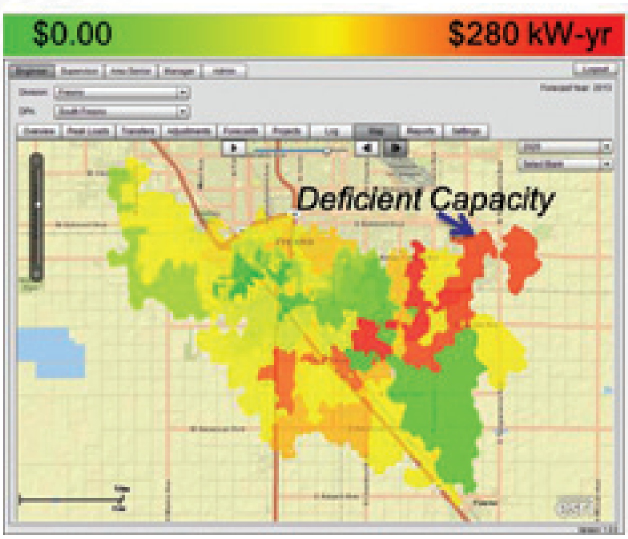


Figure 3 Spatial Identification of Deficient Capacity

Using both top-down and bottom-up predictive models to forecast growth, we know when the capacity is needed. In Figure 4, projected demand is compared to circuit capacity. The analysis compares both the expected and weather extreme utilization factors. The red dots are historical summer peak MWs back to CY 2002. The solid red line is the forecasted summer peak loads out to CY 2020, under normal weather condition (1-in-2 year probability). The dotted red line is the forecasted summer peak loads under more extreme weather conditions (1-in-10 year probability); capacity is shown by the solid yellow line.

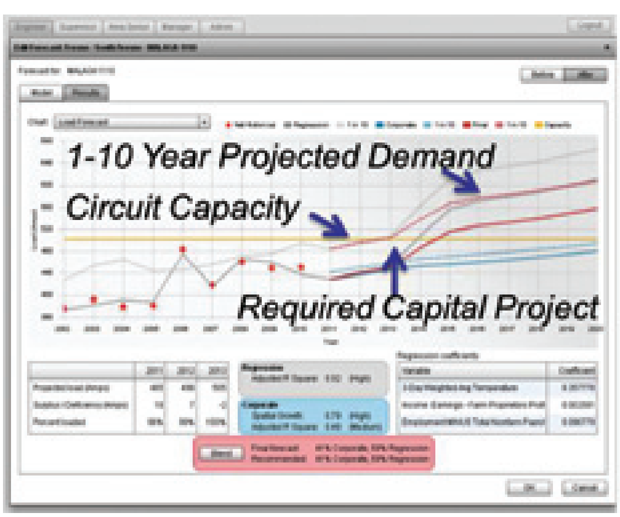


Figure 4 Capital Project Planning – Growth Exceeds Capacity by 2013

The new projects are then added to the system. In our case a virtual power plant and its demand reducing capabilities are added to the spatial model. The impacts on the capital budgeting decision are shown in the following Figure 5. The capacity expansion is no longer needed. The value of the project can be measured using the avoided capacity cost that would have otherwise been spent on the capacity addition. In our case the benefit is equivalent to a $219/kW capacity investment, as shown in Figure 6.

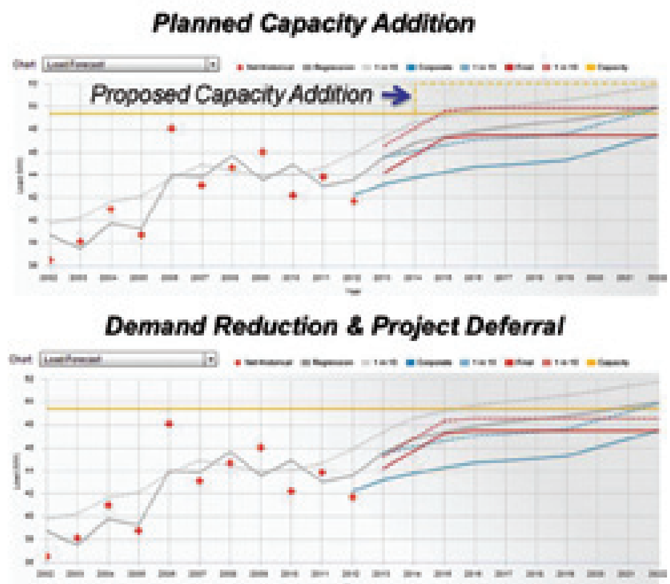


Figure 5 The Proposed Project Can Defer Capital Investment

Investment	Annual Cost
$4,700,000.00	$ 427,375.27
DSM Savings Requirement	Avoided Cost
1952 kW	$ 218.94

Figure 6 The Avoided Cost Value of Deferring Capital Investment

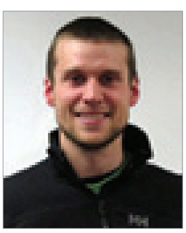
The issue is whether targeted investments in energy efficiency or DG could offset investments in T&D equipment or even help delay the need for new generation. For example, say your system average T&D avoided cost is $40/ kW-year. With that, your ability to implement cost effective energy efficiency will reach a specific limit. However, if the T&D avoided cost is $300/kw year for certain locations that are faster growing and or over-utilized, you might find that a lot more can be done in those targeted areas cost-effectively that might exceed what you would do just using a system level average. Furthermore, if you have an energy efficiency regulatory recovery mechanism that has a shared savings component, or some form of incentive that the utility can obtain for implementing energy efficiency, a better understanding of the sub-regional avoided costs (as opposed to the system average) could provide a boost to the utility incentives.

In summary, spatial transmission and distribution planning tools are increasingly needed to solve the complex short and long term planning tasks. The transmission and distribution engineers play a central role in the planning process as the locational needs of the distribution system increasingly become the focus of the capital allocation process. The strategic benefits of spatial resource planning (SRP) are listed below.

Strategic Benefits

- Ability to forecast up to 100 economic influences, by circuit, in addition to weather. We are finding that economic risk often trumps weather risk.
- Automated regression model fitting, with recommended forecast results, so planning engineers can minimize time spent developing forecasts.
- A GIS spatial forecast, based on 20 years of NASA satellite histories, modeling geographic influences unique to your regional customer base and the landscape.
- Ability to target DSM or DG to target circuits, without jeopardizing reliability.
- Comprehensive quality checking, process review, and log history for use in data requests and defensibility, as well as oversight and management during the forecast period.
- Ability to directly integrate solar forecasts, EV forecasts or other micro grid impacts, down to the customer level.
- Quick export to your power flow analysis tool.

About the author



Scott Smith is Director, GIS at Integral Analytics, Inc. He serves as Lead Developer of proprietary geo-spatial risk-based electric distribution planning application, LoadSEER. Specializing in remote sensing techniques, land change modeling, risk-based spatial electric load forecast simulations, and electric vehicle impacts on electric distribution systems, Scott helps meet the planning and forecasting needs of T&D and demand side management planners by giving them the ability to model changes in electric demand over space and time. Projects include software support to forecasting groups at Duke Energy, Pacific Gas & Electric, Avista Utilities, PacifiCorp, Kansas City Power & Light, Northern Virginia Electric Cooperative, and Nashville Electric Service.

High Voltage Underground Cable for Substation Expansions with Space Constraints

Turnkey approach ideal for ensuring successful project

By Peter Ebersold

Substation expansions can become extremely complicated when space is limited. That's when use of high voltage underground cable comes into its own as a viable option. What makes the option even more favorable is a turnkey approach, in which the high voltage underground cable provider provides the cable, terminations, and testing and documentation.

At a recent substation expansion project located near Buffalo, NY, where expansion of a substation yard and extension of an overhead 115 kV bus was impracticable and relocating facilities within the substation was not an option, Seymour, CT-based Kerite Company provided turnkey underground cable installation services that allowed new capacitor banks to be installed and energized in a reasonable amount of time and for reasonable cost.

Buffalo area project required novel solution

New York State Electric and Gas (NYSEG), a subsidiary of Iberdrola USA, needed to add capacitor banks to improve the electrical system to handle load growth in the Buffalo NY area. The utility, which serves 877,000 electricity customers and 261,000 natural gas customers across more than 40 percent of upstate New York, chose to install two new 115 kV, 25 MVAR switched capacitor banks at Big Tree Substation, an older facility constructed in the 1940s. The substation feeds the Ralph Wilson Stadium, home of the Buffalo Bills, and new capacitor banks were important for ensuring overall system improvements and supporting system voltage in the area.

Consulting engineers were brought in to design the project. The company provides engineering for investor-owned and cooperative utilities, and works on everything from wind farms to industrial clients. Senior substation engineer Stan Bail explains that, while the Big Tree Substation seemed large, it was actually impossible to add both banks above ground as is commonly done with substation expansions. There was a wide open space on the south side, but the north side was very close to a fence, with a house just outside the fence.

"We came to the conclusion that the banks had to be underground because transmission lines were in the way," said Bail. "We couldn't place the capacitor banks off the existing bus, because it was 35 feet in the air and there was no room to place the capacitor banks under the existing structure."

According to Bail, they had room within the substation fence if the overhead wire bus extended to the area where the capacitor banks would fit. The issue was that NYSEG needed two capacitor banks and two breakers. Since the bus was split, with one on the north end and one on the south end, the best solution would be taking the two locations from overhead to underground. They then ran the underground cable, coming up at one central location, terminating the underground cable and connecting to two different circuit breakers and two different capacitor banks. The solution was an uncommon one for a substation; underground cable transmission lines are more frequently used when an airport is nearby and it is important to keep circuits from interfering with airport operations.

After deciding on the engineering approach, Bail began looking for a company that could supply the cable, terminations, and testing components. He consulted with the client about their existing relationships with suppliers of high voltage underground cable, and then began discussions with the turnkey firm as it that had a reputation for high quality high voltage underground cable and a great deal of recent installation experience. He decided that Kerite was a good fit. "I explained the substation project and found it was a perfect match – we needed high voltage underground cable and they had services to provide."

Turnkey approach selected for cable runs

The design included a conduit system to facilitate cable pulling from the bus area to the capacitor bank, including a conduit plan showing how and where to place the 6-inch PVC conduit, with one conduit per cable per phase. After the conduit system was installed, Kerite brought the cable to the site for an electrical subcontractor to do the cable pulls. Instead of working with one large 1300 foot reel, it cut each run individually to length on smaller reels, which are easier to store and make pulling the individual runs much faster and simpler. This allowed the subcontractor the flexibility of pulling one phase and leaving it if necessary, then returning the next morning to pull the next phase.

The north end connection cable was about 275 feet, while the south bus connection underground cable link was approximately 150 feet. Each end of the connections requires three terminations (one for each phase), so there were a total of 12 terminations at the substation, each one being 6.5 feet tall.

Because of the complexity of the project, Bail was especially attracted by the turnkey installation services that were offered, including supplying the cable, doing the terminations, and conducting the testing. The testing included both high voltage DC high potential testing at the factory to ensure that there were no defects, and additional lower voltage field testing.

According to Bail, the project went so smoothly that they have now written into their standard specifications for similar projects that the electrical contractors are required to hire Kerite for cable and terminations.

"There was a great deal of cooperation between Kerite and Northline Utilities onsite," said Bail. "When you are terminating cables it is extremely important to avoid any wet conditions. Each one of the terminations took hours of sanding and dressing the cable after it was pulled, and Kerite needed a shelter to keep the wind, mist and rain off while doing the terminations. Northline built a shelter to keep them dry so they could keep working through whatever conditions the weather threw out there."

He adds that he plans to use the companye for another capacitor bank in the Rochester, NY area, where underground cable is needed because there is no space to expand the substation. "When you are limited by space, underground high voltage cable is a viable option when compared to other more expensive substation expansion alternatives."

About the author

Peter Ebersold is the Director of Market and Product Development for the Kerite and Hendrix brands at Marmon Utility, a Marmon Engineered Wire & Cable/Berkshire Hathaway Company. Prior to Marmon Utility, he was a Marketing Director at Honeywell and a Business Unit Manager at Perkin-Elmer. He started his career as an Electrical Design Engineer. Peter has Bachelor's and Master's degrees in Engineering.

THE BIGGER PICTURE

BY SCOTT ZAJKOWSKI

Live Data – The Keys to the Energy Kingdom

Distribution line monitoring is an absolute requirement for utilities that want to reach a truly optimized and self-healing smart grid. Electric utilities today are faced with an antiquated distribution system that lacks transparency; and without a full understanding of the distribution system in real time, they are unable to react in a timely manner, making decisions from the substation to the edge of distribution system. A major focus in today's smart grid projects is Distribution Automation (DA), which is creating a fully controllable, flexible distribution system with embedded intelligence. This grid intelligence stems from Information (Distribution Line Monitoring) and Communication and the link between this hardware and software is communication. Distribution Automation stems into two main areas called self healing and also known as FDIR (Fault Detection Isolation & Restoration) or FLISR (Fault Location Isolation and Service Restoration) and Grid Optimization better known as Volt VAR Control (VVC) or Volt VAR Optimization (VVO). Implementing these latest smart grid applications requires nodes or monitoring points to provide utility distribution systems with real time intelligence.

Volt VAR Control or Volt VAR Optimization requires a mix of hardware, software, and communication. Integrating LTC, Capacitor banks and Voltage regulators are controlled in real time based on data from the field. These various types of hardware help provide some intelligence, however, integrating monitoring points throughout the distribution line to end of line (EOL) is the true back bone and support of these smart grid applications. To truly optimize the distribution system coordinated control of the voltage and VAR is paramount. This hardware in the field must be operated in coordination in order to create an efficient distribution system. This enables more efficient distribution of power while better utilizing utility assets, preventing over burdening of equipment or hardware. Voltage and current sensors must be integrated into the field to support these Volt VAR applications; these monitoring points can be integrated on either the primary or secondary side. The primary side is typically referred to as medium voltage (MV) and the secondary side is referred to as low voltage (LV). Monitoring provides utilities with the tools to better anticipate problems and make fast, localized control decision throughout the distribution system.

Volt VAR Control or Optimization (VVO)/ (VVC) provides utilities with the ability to be more efficient and reliable. Across the country many states have set ambitious goals to reduce energy consumption and CO2 emissions (greenhouse gases). In order to reach these goals the electric utilities will need to significantly invest in their distribution system with technologies such as VVO and VVC which enable these utilities to reduce electrical demand, losses and energy consumption. The benefits of VVO or VVC are significant for both consumers and the utility. VVO/VVC reduces peak demand and increases the grids capacity which presents the need for additional infrastructure and new generation. Consumers also benefit from reduced power consumption, which equates to lower electric bills and finally the environment benefits from reduced waste of early product failures and reduced greenhouse gas emissions. By actively monitoring the distribution system utilities are able to better respond to the increasing customer demand for higher reliability and power quality. Distribution line monitoring and VVO/VVC provide utilities with actual data rather than inaccurate modeled responses, providing a multitude of system benefits.

Implementing VVO or VVC provides significant benefits. Operating the distribution system at lower voltage levels can provide a one percent to three percent reduction in total energy. This results in a two to four percent reduction in kW demand and a four to ten percent reduction in kVAR. VVC and VVO enables utilities to be more efficient, and if the United States was just five percent more efficient, the impact would be monumental equating to the elimination of the fuel and greenhouse gas emissions from 53 million cars.

One main technology that can be utilized in order to provided real time monitoring are line post sensors. These line post sensors must however be integrated with intelligence as to pull the data back to the utility control center or SCADA system. Integrating end of line sensors with line posts sensors provide utilities with the means for grid intelligence, which will enable the line post sensors to provide real time information, equipping utilities to make decisions to optimize the distribution system.

Another form of monitoring to consider is on the secondary side of the distribution transformer. This form of monitoring also provides support and intelligence to VVO/VVC applications. Smart Transformers or secondary distribution transformer monitoring is an application expected to grow significantly over the next seven years. This form of monitoring requires the integration of monitoring devices such as end of line sensors or products with the secondary distribution transformers, which can be single, or three phase pole top or pad mount transformers. Integrating this throughout the distribution system provides utilities with the capabilities to manage critical customers; the utilities assets and it can also provide visibility into the electric distribution system. This form of real time monitoring can greatly vary depending on the device. Some simply supply only voltage while others provide more sophisticated monitoring and measurements. The devices typically provide utilities with voltage, loading and external temperature of the transformers, which allows the utilities to optimize the use of their assets. New transformer monitoring devices being announced at DistribuTECH 2014 will provide a more comprehensive view of these assets. They will a provide gas analysis called TCG (Total Combustible Gas), internal oil temperature along with voltage and current reading. These new monitoring technologies provide utilities a way to more effectively and efficiently utilize their assets within the distribution system. Some may say the cost of these transformers does not warrant monitoring, however, secondary transformer monitoring can be integrated and leveraged with a variety of utility smart grid projects in order to offset the cost while improving the distribution system. Secondary transformer monitoring can also be leveraged with Volt VAR Optimization, Outage Notification, Revenue Protection (Electricity Theft), Asset Management and Power Quality smart grid applications.

Secondary transformer monitoring will also become increasingly important as distributed generation (DG) or Renewable Energy becomes more abundant. As distributed generation is integrated into the distribution grid, additional complications will arise such as power quality issues, load and phase imbalance, reverse power flow and there could even be safety implications. The key to handling DG is to implement bi directional sensors and VVC or VVO, which will provide awareness and real time monitoring.

Another form of distribution in need of line monitoring is theft detection, a major problem for utilities across the world. Electricity theft in the United States equates to $6 billion in losses annually, which can cost utilities one to three percent of their revenue. These losses are then passed on to the consumer. The integration of AMI or AMR (Smart Meters) has helped alleviate some energy theft at the meter but where the largest problems lie are when thieves wire into the distribution system or hook up to distribution transformers. This is where distribution line monitoring can be most beneficial in detecting and preventing further losses for the utilities and their customers, these devises help give the utility the upper hand by providing real time data to compare with AMI/AMR Meters. If discrepancies and usage are different, electric utilities are able to detect and pinpoint where the electricity theft is occurring.

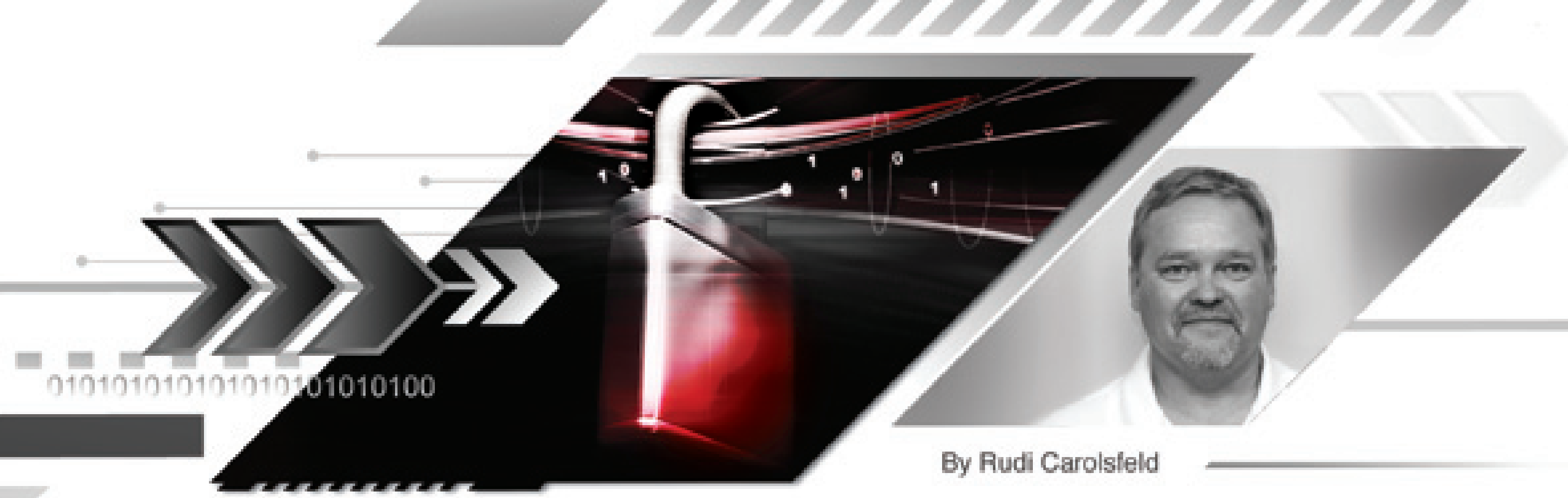
A self-healing grid is another area of focus for utilities; a self-healing grid utilizes FDIR (Fault Detection Isolation and Restoration) or FLISR (Fault Location Isolation and Service Restoration) to improve reliability and performance of the distribution system. This allows utilities to quickly respond to faults and restore power to as many customers as possible by quickly isolating or sectionalizing the affected area. Distribution line monitoring is a key support tool for this application.

These intelligent sensors through the distribution system provide real time outage notifications enabling utilities to quickly react and restore power to the majority of the customers in minutes, not hours. A self-healing grid provides many benefits to both the utility and the customer; FDIR and FLISR greatly reduce the number and duration of outages, which improves the reliability and delivery of power and also reduces maintenance and improves the safety for utility workers. Distribution line monitoring provides FDIR and FLISR software with real time data reducing the time to get customers back on line and helping to pinpoint and direct utility workers to the affected areas, saving time and money.

Distribution line monitoring provides utilities with the information needed to make decisions at the edge of the grid and it is imperative to grid optimization and the future self-healing grid. The addition of smart sensors will provide utilities with the ability to make intelligent decisions to control voltage, VAR, outages, power quality and a slew of other issues. This real-time, accurate voltage and current sensing provides utilities with a comprehensive view of the distribution systems load and voltage conditions leading true smart grid.

ABOUT THE AUTHOR

Scott Zajkowski is part of the North American Business Development group with IUS Technologies who develops end of line devices for the smart grid including their Born Smart TM series of sensors. With an MBA from Indiana University Kelley School of Business, Scott is an ambitious and driven marketing professional with proven success in developing and executing strategic marketing and advertising campaigns with companies such as Lakeshore Energy and HP Products. Previous to IUS, Scott worked at International Truck & Burger King in Packaging Engineering and Management utilizing his undergraduate degree in Packaging Engineering from Michigan State University.



By Rudi Carolsfeld

SECURITY SESSIONS

Lean + Green + Safe

Recover revenue from energy theft while improving grid efficiency, reducing carbon emissions and increasing public safety

When Jim got the call from the fire department that a recent house fire was caused by illegal wiring for basement lighting installed to grow marijuana, he wasn't really surprised. Everyone knew that these grow-ops exist, and the police had a good record of finding them and shutting them down. Like mushrooms after the proverbial autumn rains they keep coming back. But with this last fire things were different: a firefighter was recovering from serious electrical burns that came from contact with live wires while fighting the fire. The main power breaker had been shut off, but no one knew that the growers had diverted the power off the medium voltage lines to a hidden transformer and breaker panel in the attic. The firefighter was expected to live, but it was a very close call.

This scenario is not pure fiction. The risk to property and emergency response crews is real. Grow operators and drug lab operators routinely try to hide their efforts, and stealing power is one of the key tricks to keeping the operation under the radar. Smart meters have eliminated tampering by everyone except the very ill-advised, so the only way to avoid hefty power bills – and the attention these can draw – is to tap into the grid well before the metering point.

Globally, energy losses cost electrical distribution companies more than $200B per year. In the USA, this figure is about $24B and approximately one-quarter of that – $6B annually – is due to theft. The culprits are widespread and touch all corners of society, from the high-end homeowner trying to save a few dollars to keep the house cool or the swimming pool warm, to the local pizza joint or nightclub owner that bribed his electrician to bypass the main breaker panel while renovating the adjoining expansion.

Some electric utility companies refuse to believe they have much theft. A very lean distribution grid might run with around 3.5 to 4.5 percent technical loss. Nontechnical losses, which include theft as well as metering errors, unmetered premises, and other commercial errors) can range from a low 0.5 to a full 100 percent on certain distribution lines.

Recovering these losses translates into pure profit:

- The electricity has already been generated and transmitted through the system.
- Every stolen kWh that is disconnected no longer needs to be generated.
- Every stolen kWh that is not generated does not create greenhouse gases.
- Every stolen kWh that is paid for goes straight to the bottom line on the annual financial report.

And the payback also pays forward: once the theft or loss has been discovered and recovered, the avoided losses and increased revenue will continue for years.

Most power utilities have found that the promise that smart meters would eliminate all theft cannot be fulfilled. Experience shows that a reduction of 20 to 25 percent in theft can be attained but the rest can only be found by investigations on the upstream lines. As awareness increases of the capabilities of smart meters and meter data analytics, thieves will increasingly turn to upstream diversion to meet their needs.

This creates a very challenging problem for the distribution company:

- How can they cost-effectively and quickly pinpoint theft?
- Find those wiring errors and incorrectly installed smart meters?
- How do you pinpoint assets that are over or near rated load?
- Identify poor power factor, phase imbalance, and load anomalies?

Unfortunately, too many grid operators do what Jim did in our opening story – wait for the phone to ring with a police report, news of a house fire, or an irate customer complaining about yet another outage.

The conventional alternative is very expensive, with the cost of each line-mounted, pole-top or pad-mounted monitoring device typically around $3,000 to $4,000, accounting for the device, installation, the communications and the data integration. For even a modest distribution company with 1,000,000 customers, 500 feeder lines and perhaps 200,000 transformers, the cost of such a system could easily be tens of millions of dollars. The result is that the distribution grid remains 'dark' except for a few problem areas where monitoring is deemed worthwhile. In the end, generating 52 weeks of ongoing continuous data from any one such monitoring location has limited value once theft, diversions, and losses have been eliminated. Data processing and management costs, IT costs, and operating costs increase, with diminishing returns.

True Grid Insight and SenseNET

SenseNET offers a more pragmatic and much more affordable approach to implementing a theft & loss mitigation program; it makes it possible to gather one week of load profile data from each of 52 locations for the same cost as 52 weeks at one location. Such a temporary line sensing system can be used to quickly and easily find the cause of theft or other losses, and then used again and again to discover more.

With the SenseNET data stored in the cloud, and using True Grid Insight software analytics to perform intelligent energy audits one distribution line at a time, the IT costs are very low and the benefits immediately apparent. Theft and losses are found immediately, leading to direct revenue recovery. Heavily loaded transformers, severe load imbalances, and other operating conditions are immediately rectified. Over the course of 2 to 3 years, the system can give a 'roving' view of the whole distribution grid, built up from a patchwork of snapshots of real operating conditions on the lines. This leads to True Grid Insight, and makes it possible to plan for ways to optimize the grid operation, more accurate demand forecasts, and much more.

By quickly eliminating theft and finding losses, the distribution grid company can:

- increase grid efficiency to gain higher reliability
- reduce unnecessary generation to lower greenhouse gases
- eliminate illegal wiring leading to fewer building fires and higher safety

Rather than fixed monitoring at just a few hundred or thousand points in the distribution grid, a roving sensor system like SenseNET makes it possible to create a high-resolution view of actual distribution grid operating conditions. This approach shines a light on the dark corners of the grid downstream from substation SCADA and upstream from smart meters. The resulting True Grid Insight enables grid optimization, eliminates theft, finds high loss transformers and transformers with imbalanced loads, loads with poor power factor, and much more.

Actual deployments have found the recovered revenue is substantially greater than the cost of deploying the system. One early 1-week deployment was able to pinpoint almost four times as many losses compared to the system the customer was using previously, which included smart meters, tamper detect flags, load profile analysis, outage alerts, etc. Savings and recovered revenue is already being measured in the tens of millions of dollars, for utilities throughout North America and internationally.

As the operator of an electrical coop, investor-owned utility or any other distribution company, you have an obligation to your members, your owners, your investors and your community:

- Avoid ongoing losses!
- Improve public safety!
- Reduce your carbon footprint!

ABOUT THE AUTHOR

Rudi Carolsfeld joined *Awesense* in 2013 as Vice President of Sales and Chief Customer Advocate, defining and guiding the global sales and marketing efforts for the expansion of the company's portfolio of revenue assurance product and services globally.

Rudi has more than 20 years of technical sales and marketing experience through his engagements with two other outstanding companies solving Smart Grid problems that were both market leaders in their respective fields. He was at Power Measurement Ltd. from 1993 to 2007 where he held numerous roles in engineering, marketing and domestic & international sales, holding the title of Sales Director for Europe when the company was acquired by Schneider Electric in 2005. From 2007 to 2013, while at *RuggedCom Inc.*, Rudi had responsibility for sales, holding the position of Vice President Asia Pacific when the company was acquired by Siemens in 2012. Under the Siemens *RuggedCom* banner, he was Vice President, Global Product Business Development.

Rudi has a Bachelor's degree and a Master's degree in Electrical Engineering from the University of Victoria and has sat strategic marketing and technical Japanese courses at Stanford University and MIT, respectively. He has been a member of the Institute of Electrical and Electronics Engineers (IEEE) since 1983, has authored numerous technical journal papers and white papers, and is co-inventor of a multi-featured power meter. Rudi lives with his family in Victoria, Canada.

Guest Editorial

With Big Data, Utilities Enter the "Amazon" Era

By Amit Narayan

Big Data & Analytics: A Widespread Phenomenon

Smart meters and other intelligent field assets are allowing utilities and others in the electricity supply chain to streamline operations and cut costs. Eliminating manual meter reads alone is collectively saving billions of dollars annually and reducing millions of truck rolls.

And this is just the tip of the iceberg. Advance Meter Infrastructure (AMI) is also building an incredibly valuable asset that will prove even more valuable in the long run – data about customers, behavior, and ongoing operations.

'Data' can be a difficult asset to value, especially when the proper analytics systems are not in place to harvest the full value of all data streams. But take a look at a company like Google. The search engine dominates information management because it provides quicker and more accurate results to queries than competing technologies. Its data centers and algorithms continue to improve because accumulated queries allow it to deliver more precise results (with fewer underlying processor cycles) the next time around.

Or consider Netflix. The entertainment service has mined data about the behavior of its viewers to become a successful TV producer. No more guessing what the audience wants:

- Netflix can intelligently anticipate it with a relatively high degree of accuracy.
- People are predictable. It's one of the most important, but one of the most underappreciated, insights of the Internet era.

Similarly, Amazon has developed recommendation engines, optimized data centers and the logistical framework that have allowed it to become the most dynamic retailer in the world. Customers can navigate the site, and be prodded into impulse buys with personally targeted discounts, because Amazon has figured out how to guide them by studying their own past behavior.

Amazon has even taken it one step further by parlaying its expertise in data management into Amazon Web Services, one of the largest cloud service providers in the world. It's a remarkable transformation: if you asked someone five years ago which company was destined to bring cloud platforms to mainstream businesses, they probably would have guessed IBM or Oracle, not the people who invented Cyber Monday. Data analysis is a competitive advantage as well as the foundation of their operations.

Utilities are sitting on the verge of a similar transformation. Historically, utilities consumed a relatively small amount of data for their size. Now, the proliferation of smart devices has created a veritable tidal wave of digitized information. A typical smart meter is serving up 2,880 meter reads a month, versus the one per month delivered by an analog meter. By 2020, the 980 million smart meters around the world will generate 8241 petabytes of data a year or more than 68,000 times more data than that is currently held in the Library of Congress. Building management systems for office buildings will generate around 100 gigabytes of information a year.

This data, if mined and analyzed in constructive ways, will ultimately give utilities a way to see patterns amid chaos. They will be able to accurately determine power going to plug loads versus HVAC or lighting, visualize and calibrate consumption rhythms throughout the day or predict the behavior of classes of customers or specific individuals.

With these forecasts in place, the next step is actually comparatively easy: harnessing these predictive abilities to fine-tune transmission, distribution and consumption. Demand response is already being transformed. Conventional demand response services rely heavily on planning, phone calls and advance organization. Demand response events are truly 'events' and occur only a few times a year.

Data-based systems turn demand response into demand management. Power savings can be harvested from hundreds of thousands of customers, not just a few. Securing participation of specific individuals becomes less crucial: if one customer can't participate, many others can. Events can be organized quickly through a network and, because events can be scheduled more frequently, customers become acclimated to the service and increase the frequency and depth of their participation. Demand response goes from being an unusual event that requires a perceived sacrifice to a monthly, or even daily, occurrence with a benefit that is articulated on in dollars and cents on monthly bills.

Similarly, industrial customers will begin to adopt cloud-based systems to help control demand charges. Demand charges can account for 30 percent of a large power user's bill. By employing intelligent automation, large power users can turn down less essential power consumption (like daytime lighting), maintain production flows and avoid excessive peaks. Without data, large power users can only guess what their power demands might be: data effectively eliminates risk by tightly defining probable outcomes.

Data can also be used to throttle power theft. The World Bank estimates that $85 billion in power gets stolen every year. In emerging nations, the problem is a never-ending crisis: approximately 30 percent of the electricity gets stolen in India, leading to chronic outages, lower productivity and higher rates. But it's also a problem in the U.S. with $6 billion alone being siphoned off by illegal marijuana growing operations, among other activities.

Unfortunately, it is also extremely challenging to stop. Electrons don't have serial numbers. There is no forced entry – the thieves live or work in the same location where they steal power – and police do not have the resources to dedicate to it. Utilities, rightly, also do not want to send employees to illegal drug operations.

With data, utilities can identify anomalies; compare actual consumption with billing rates and other parameters to hone in on probable suspects quickly and at a safe distance. The benefits and the results that we will see from data-based services will cause the Berlin Wall that separates utility operations, or OT, from IT to crumble sooner than many expect.

Time-of-use (TOU) programs, buffering for solar and wind farms, grid balancing will all suddenly become more feasible through analytics. Rather than just know supply, utilities will have their fingers on the pulse of demand. Incentive programs can be sculpted for particular customer segments and designed for maximum participation. Forecasting has always been the Achilles' heel of TOU or efficiency programs. Utilities and regulators put the programs together, but then struggle to find participants. In many jurisdictions, incentive payments remain invisible. Analytics succeed because they eliminate the guesswork.

The power industry will never be a rapid technology adopter and for very good reasons. Utilities are the ultimate just-in-time industry. They cannot go offline over the weekend to conduct routine maintenance like a gaming site. Likewise, customers aren't going to shrug at outages, chalking it up to the cost of adopting new technologies: they will view it as an inexcusable failure.

But the economic arguments in favor of employing data – and, more importantly the value in the insights apparent as utilities and customers become immersed in these systems – will become overwhelming. With this technology, utilities can shift from being perpetually mired in reactive mode, i.e. the kind of company customers only remember when something goes wrong. They can provide new services, lower their own operating expenses, reduce outages and increase customer satisfaction at the same time.

In this case, the future is easy to predict.

ABOUT THE AUTHOR

Dr. Amit Narayan is the Founder and CEO of AutoGrid, Inc. From 2010 to 2012, he was the Director of Smart Grid Research in Modeling & Simulation at Stanford University, where he continues to lead an interdisciplinary project related to modeling, optimization and control of the electricity grid and associated electricity markets. Prior to founding AutoGrid, he was the Vice President of Products at any Magma Design Automation. Dr. Narayan also founded Berkeley Design Automation, Inc. (BDA), a venture-backed company in analog and radio-frequency semiconductor design software. In 2006, Dr. Narayan's received the EDN's 'Innovation for the Year' award. Dr. Narayan received his B. Tech. in Electrical Engineering from Indian Institute of Technology at Kanpur and Ph.D. from University of California at Berkeley. He has published over 25 papers about design automation, holds seven U.S. patents and is an active advisor to several startup companies in the Bay Area of San Francisco.

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