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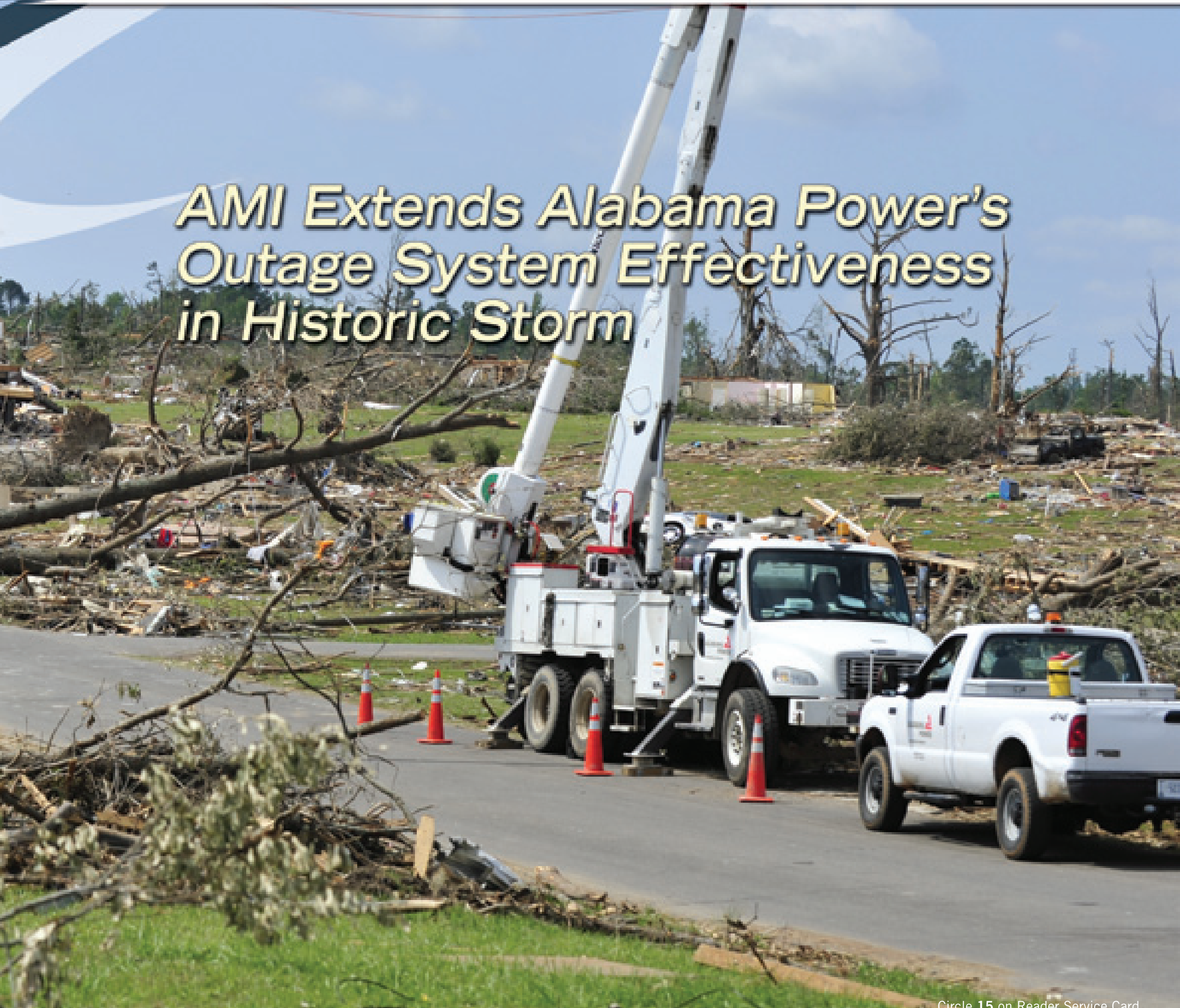
AMI Extends Alabama Power's Outage System Effectiveness in Historic Storm



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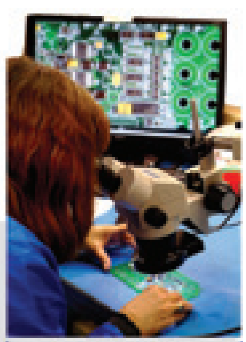

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GridLines

Michael A. Marullo,
Editor in chief

Knee-deep in the Hoopla

About a hundred years ago (well, in 1985, actually), a reincarnation of the legendary 1960s rock group, *Jefferson Airplane* – by then known as *Jefferson Starship* – released an album titled, *Knee-deep in the Hoopla*. Some of the hardcore Rock 'n' Roll junkies labeled it a sell-out to the Soft Rock/Disco crowd, but I thought it was one of their better collections, albeit a very different music genre from their earlier, mostly psychedelic, roots. For those not entirely familiar with this highly technical term, 'hoopla' means: "*informal excitement surrounding an event or situation, especially when considered to be unnecessary fuss.*" Yep, that sure sounds like our Smart Grid, doesn't it?

Okay, this is just my way of broaching the point that the Smart Grid is finally beginning to show signs of emerging from the 'hype' phase (the hoopla, if you will) into more of a reality phase. There has already been a lot written about the hype surrounding Smart Grid, which is in itself sort of a 'hype-ish' term for something that I think most experts would agree has been quietly – and many would argue, much too slowly – transforming the power grid for decades.

I really don't want to dwell on what has gone wrong over the past few years. After all, there's plenty of ammunition there if we wanted to delve into it – but let's not. Instead, let's talk about what is being done and what still needs to be done along the path to the future. That all starts with what I'll call 'quiet progress'.

Despite Smart Grid seeming like nothing but talk, talk, talk, talk, talk – many of the right things have indeed been happening. Yet to observe the general media, one would think that the only Smart Grid progress made over the past two years was the initiation – and in some cases, the completion – of smart meter deployments.

But, the reality is that smart metering is only a relatively small portion of what Smart Grid is really all about. Significant strides have been made in areas like the deployment of phasor measurement units (PMUs), which dramatically improve state estimation; an upsurge in the deployment of feeder automation to better deal with fault detection, isolation and restoration (FDIR); volt-var optimization (VVO); and considerable advances have been made in reliability and critical infrastructure protection, just to name a few of the more important ones.

However, in the last few weeks of 2011, I started seeing headlines and reading stories about how the investment community and – as some articles implied – the entire utility industry, has grown weary of Smart Grid. The broader implications are that investments might start to wane in this new year, to which my question is this: How does one get burned out on something that has only just begun?

The only way that I know to draw a conclusion like that, is to have believed all the hype in the first place and then simply give up because the hype failed to deliver – and that's exactly what seems to have happened here. Indeed, a lot of people have been led to believe that smart meters ARE the Smart Grid (and vice-versa), and as I certainly hope those of us on the inside of this issue are well aware, that is simply not the case. One important piece of good news is that we now have a vehicle to help begin to correct this pervasive misunderstanding among the group that understands Smart Grid the least: consumers.

GridLines

Michael A. Marullo,
Editor in chief

To help with that, a Smart Grid Consumer Collaborative[1] – "a consumer-focused nonprofit aiming to promote the understanding and benefits of modernized electrical systems among all stakeholders in the United States" – has recently been formed to help drive these objectives home. (Pun intended!) Much has been written – and in the future will (appropriately) continue to be written – about consumer empowerment and customer education.

The notion that users need to be educated (reprogrammed?) to understand the realities of smart meters is right on the money. But, besides educating consumers about how power is produced, delivered and metered, there are other messages that need to be conveyed to them as well.

Among the first, and perhaps the most important, of these messages is that just because smart meters didn't magically lower everyone's electric bills (talk about hype!) overnight, that doesn't make the Smart Grid a flop!

Clearly – and unfortunately – this is not only a technical issue, but one that is politically charged as well. There are those who feel strongly that the government should not play a central role in financing Smart Grid initiatives, and they do have a point. However, on balance, modernizing the nation's electric grid is a legitimate national security issue, and occurring in the midst of a recession, it seems that we could certainly do worse with our tax dollars – and often do.

As we look forward to another new year, let's look harder at transforming the grid from one-way power flow and one-way communications to the bidirectional power and communications networks that are desperately needed to meet the needs of the 21st century and what once again appears to be a growing economy. Again, there is much to be done. The tasks range from upgrading substations and re-conductoring power lines to finding ways to assimilate large amounts of data and create better, faster and more reliable communications channels. And, with a declining infrastructure and an aging workforce working in tandem to hinder our progress, it's time to rise to the occasion.

You've heard it before, and you'll undoubtedly hear it again: '*Smart Grid won't be fast, and it won't be cheap*', so we can't afford to go into this challenge thinking that it will. And no matter how much we spend or how long it takes, smart meters alone won't get the job done. The only way is to pursue a comprehensive and methodical long-term commitment to addressing the numerous challenges that still remain ahead. (Less hype and less hoopla would be good here too.) – ***Ed***.

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[1] *See Guest Editorial by Patty Durand, SGCC Executive Director, in the October 2011 issue of EET&D in the Magazine Archive section at electricenergyonline.com.*

INDUSTRY NEWS

Itron and Tantalus Provide Public Utilities with Transition Path to 2-Way Smart Grid Communications

LIBERTY LAKE, Wash., and RALEIGH, NC, — January 2012 — Last September, Itron Inc. (NASDAQ: ITRI) and Tantalus Systems Corp. announced a strategic partnership dedicated to delivering a wide range of smart metering and smart grid benefits to electric and multi-service public utilities. Their commitment ensures that public utilities across North and Central America will be able to provide increased levels of customer service, greater service reliability, improved efficiency and access to usage information that smart metering delivers.

This ongoing collaboration combines Itron's industry-leading electricity meters — as well as its gas and water ERT modules — with Tantalus' advanced 2-way communications network, which accommodates smart metering, demand response and distribution automation functionality. Coupling the capabilities of Itron's advanced gas and water modules into this flexible communications platform will address the unique needs of combination utilities and provides customers a cost-effective path to achieving the 2-way communications capabilities required for AMI (Advanced Metering Infrastructure) and other Smart Grid functionality, while incorporating the previously deployed Itron ERT modules.

"The combined solution delivers on the promise that all utility companies should be able to leverage their current installed base of equipment to deliver the benefits of Smart Grid to all customers," stated Philip Mezey, Itron president and COO, Energy. "We are excited about joining our technology with the infrastructure Tantalus has developed for a complete, integrated solution for our cooperative and public utility customers. Tantalus' growing success in this market space is a real advantage for Itron," Mezey concluded.

"Combining Itron's industry leadership and experience with our technology will unlock new possibilities for utilities. Together, we will leverage existing and future electric, gas and water metering endpoints to help public utilities make their grids smarter," said Eric Murray, Tantalus president and CEO.

[Editor's Note: For more information and additional details about how this type of technology partnership will help utilities cross the chasm from 1-way to 2-way metering and new dimensions of distributed automation networks, watch for the next *Grid Transformation Forum* interview in which Itron and Tantalus executives delve further into the benefits of technology migration in the March-April 2012 issue of EET&D.]

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Energy Efficiency in 2012: Forecast Is Mostly Sunny

January 2012 - Looking forward into 2012, I see more reasons for optimism than pessimism. Many states and utilities are committed to ramping up their energy efficiency programs this year and even more are considering similar steps. For example, Massachusetts electric utility programs are targeting 2.4% savings this year as part of a ramp-up rate originally established a few years ago. Many other states also have ramp-ups planned, although not as aggressive as Massachusetts. In terms of potential new states, Kansas City Power and Light has just proposed a three-year plan to the Missouri Public Service Commission that would use efficiency programs to save 0.5% of sales in the first year and 0.9% in a few years. And the Maryland Public Service Commission has just directed the state's utilities to identify additional efficiency programs to make up the gap between their current plans and state law, which requires utilities to achieve 10% savings by 2015.

The private market continues to invest in energy efficiency, although efforts have been slowed by the economic downturn. New energy-efficient products continue to enter the market and energy efficiency is one of the hot areas for "Cleantech" investments.

INDUSTRY NEWS

"For example, new LED lighting products are being steadily introduced into the market and prices are starting to come down. The CleanTech Group reports that venture capital investments in the clean technology area rose 23% in the third quarter of 2011 relative to the same period in 2010, including 34 energy efficiency deals. The Home Performance with Energy STAR program continues to expand and now covers 32 states. In the commercial sector, more and more property owners and prospective tenants are looking for "green labels" such as LEED or ENERGY STAR certification. The industrial sector starts the year with a positive outlook following 29 months of sustained expansion, with prospects for investments and hiring poised to lead to modernization and growing competitiveness globally due to low energy and skilled labor costs.

At the federal level, new vehicle and equipment efficiency standards will be issued in 2012. For example, fuel economy standards for passenger vehicles will be finalized; the draft standard, based on an agreement between auto manufacturers and the Obama Administration, calls for raising these standards to an average of nearly 50 mpg by 2025. Final decisions are due from DOE on standards for 13 products including residential clothes washers (likely based on an agreement between appliance manufacturers and efficiency groups) and distribution transformers. And recent EPA regulation updates on emissions of toxic pollutants, along with other pending regulatory updates for power plants, will encourage utilities to look at efficiency investments as an alternative to upgrading aging power plants.

A major driver in 2012 will be the state of the economy. Our economy is finally growing again, although too slowly to make a significant dent in unemployment. Fortunately, investments in energy efficiency can contribute to job growth, as energy efficiency work is generally more labor intensive than investments in new energy supplies. The Brookings Institute estimates that there are about 2.7 million clean economy jobs in the U.S., including about half a million added over the 2003-2010 period.

While there are many reasons for optimism in 2012, all is not rosy. Many states and utilities began energy efficiency programs in 2009, with funding from the American Recovery and Reinvestment Act of 2009 (ARRA or the economic stimulus bill). That funding will end in early 2012 and these programs are now scrambling to identify alternative funding sources. Policymaking in Washington is paralyzed, making new legislation unlikely, although there may be some opportunities for small steps. And while we have been making progress on energy efficiency adoption, the energy savings realized are still modest relative to the cost-effective opportunities.

Here at ACEEE, we will be working to advance three themes in 2012. First, we will be assisting and encouraging states, utilities, and others who are interested in increasing their energy efficiency efforts. For example, we are now working in Missouri, Kentucky, and West Virginia and are about to start a project in Louisiana. We are also assisting utilities and regulators to evaluate alternative utility business models and to consider energy efficiency first as aging dirty power plants are retired. Second, we will be documenting what works (and what doesn't) so that programs and policies can be as effective as possible. For example, we will publish a 45-state review on energy efficiency evaluation practices, have begun work on a comparison of energy efficiency accomplishments and policies across a dozen of the largest economies in the world, plan to identify best practice utility programs in a couple of dozen program areas, and continue to work on ways to expand the availability of energy efficiency financing. Finally, we will be laying groundwork for the future, including a forthcoming exploratory study on efficiency opportunities out to 2050 and identifying new program strategies to help reach energy savings goals as traditional energy efficiency measures, such as compact fluorescent lamps, become business as usual. In addition, we have five conferences planned-the first two are the National Symposium on Market Transformation in April and the Energy Efficiency Finance Forum in May.

Stay tuned for more news from ACEEE as we continue to release reports and blog posts detailing our efforts throughout 2012. Keep your eyes out for e-mails announcing the release of cutting-edge research we are conducting or the latest updates on our conferences planned for 2012 and beyond.

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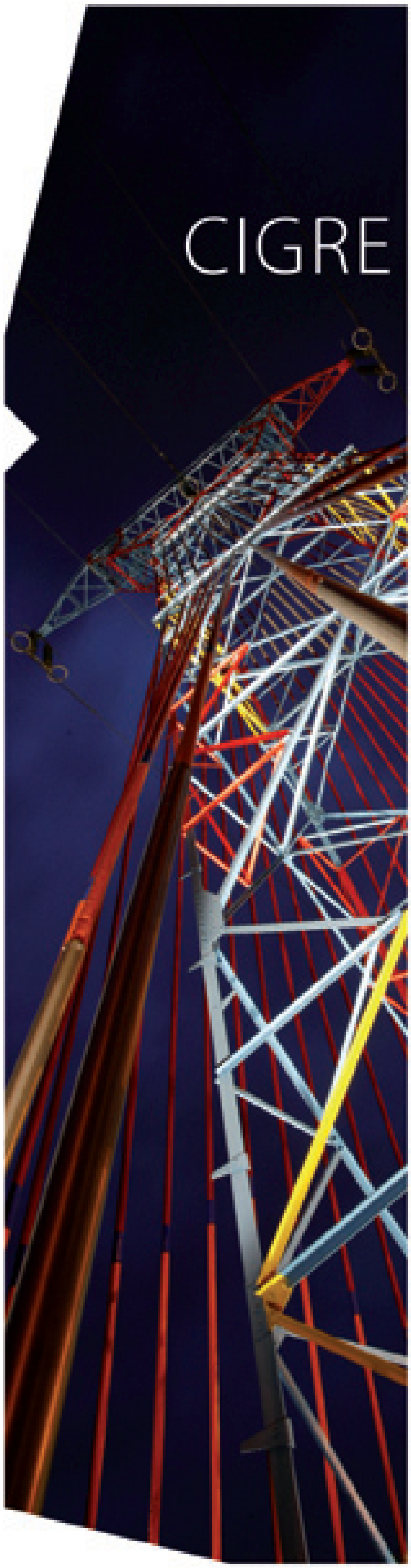
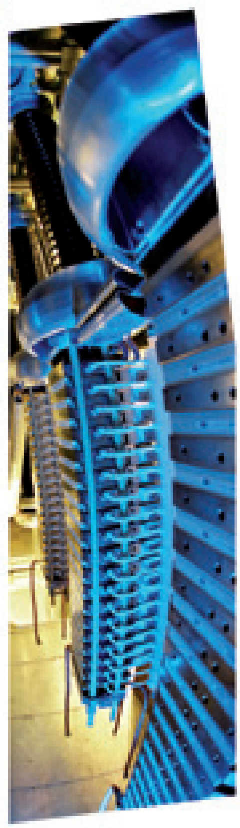




AMI Extends Alabama Power's Outage System Effectiveness in Historic Storm

By Derl Rhoades, Network Operations & Translation, Team Leader, Alabama Power Company

Alabama Power Company: A Study in Automation, Dedication & Determination

On April 27, 2011, Alabama Power Company — the Birmingham-headquartered Alabama operating company of the Southern Company — experienced one of the most devastating and deadly natural disasters in US history. Damage caused by a string of tornadoes (Cover) striking Tuscaloosa, Alabama and the surrounding area dealt a severe blow to both the communities in the region as well as Alabama Power Company, with more than 400,000 customers without power at the storm's peak. In addition, nearly 4200 poles, and as many as 400 transmission system structures were either damaged or destroyed. Besides the physical damage, a total of 243 people lost their lives — a loss that can never be restored. Yet just eight days after the storms passed, most of the affected area was up and running again, thanks to the influx of emergency workers; federal, state and local authorities; residents of Tuscaloosa and the surrounding communities; volunteers from far and wide, including those from other utilities across the country; and of course, the dedicated employees of Alabama Power Company.

But there was another ingredient in this rapid recovery — an often unsung 'hero' that works 24/7, takes no breaks, sick days, holidays or vacations, and that is always ready for the worst — whenever and wherever it may occur: Alabama Power Company's automation systems and the associated hardware and software assets. In the next few pages, you'll learn how automation of various types and forms helped Alabama Power to survive the storm and restore power to homes and businesses in record time. Moreover, you'll see how interaction and interoperability across systems helped to multiply the individual benefits and operational capabilities of each.

In the second part of the article, you'll have a chance to see how the integrity of Alabama's Advanced Metering Infrastructure and the logistics associated with their Smart Meter preparation and roll-out helped to prepare the utility for the unexpected and unprecedented act of nature that nearly wiped out an entire region — truly, a lesson in Automation, Dedication & Determination! — *Ed*.

Alabama Power Company had been preparing for severe weather to hit the state long before the morning of April 27, 2011. By daybreak, repair crews were already working to restore power to about 270,000 customers affected by a line of storms that had passed through overnight. With predictions of a dangerous, tornado-laden storm heading its way, bucket trucks and crews from utilities as far as Illinois headed to the Heart of Dixie in anticipation of more damage to come. Despite the helping hands, customers were advised to prepare themselves for extended outages.

Alabama Power Company parent, Southern Company, had begun laying the groundwork for effective response management and system modernization well before the storm clouds formed when it embarked on an initiative to have its utility subsidiaries integrate their current outage management systems (OMS) with advanced meter infrastructure (AMI) systems. By fall 2010, Alabama Power had successfully merged a proprietary OMS in service for years with an open-standards based, multi-application, fixed-base, two-way wireless communications network from Sensus Metering Systems to gain a number of key benefits, including real-time situational analysis and grid stabilization.

Storm events are common for any utility, and Alabama Power's recovery response protocol proved highly effective. The ability to collect data from smart meters and deliver it over the AMI system added a new dimension to utility operations because the information could be used to enhance our outage estimation systems. The April 27th storm that ripped through Tuscaloosa County and surrounding areas was anything but typical. Indeed, before the skies cleared it would become the most powerful, destructive event in recorded history, damaging or destroying countless utility assets. The tower-based communication network, however, remained largely intact and provided valuable information that helped those responsible for the utility's restoration efforts.

Extending OMS Limits

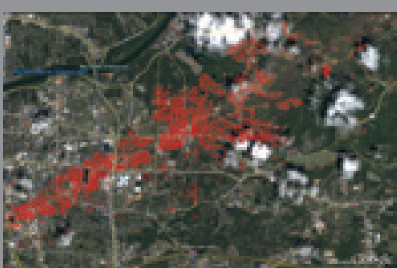
Alabama Power Company's OMS is a valuable tool that performed well the day of the storm, alerting technicians to the number of customers without power. Here's a brief summary of how the system works…

AMI Extends Alabama Power's Outage System Effectiveness in Historic Storm

Keyhole Markup Language for Outage Maps

In cases where there are power outages due to major weather events or natural disasters, the traditional functionality of an OMS may not be adequate to manage the restoration. That's when utilities will turn to Google maps for continuous updates, where reports coming directly from responders can be visually represented internally or to customer sites.

The red dots on the Google map image below indicate power outages in Tuscaloosa, Alabama, on April 27 after a tornado swept through.



Power Outages in Tornado Aftermath on April 27, 2011 in Tuscaloosa, Alabama

This geospatial imaging is based on Keyhole Markup Language (KML), a simple but powerful file format for displaying data in an earth browser, such as Google Earth or Google Maps. It was originally developed by Keyhole, Inc., which later became a part of Google in 2004. The word "keyhole" originated with a U.S. military reconnaissance satellite program developed in the 1970s.

KML uses XML-based set of standards for gathering, storing, and transmitting data for two-dimensional and three-dimensional digital maps. The KML standard was first used to power Google Earth, but other web-based map services have adopted it as well. KML has also become one of the standard map storage and transfer protocols for a wide range of GPS devices.

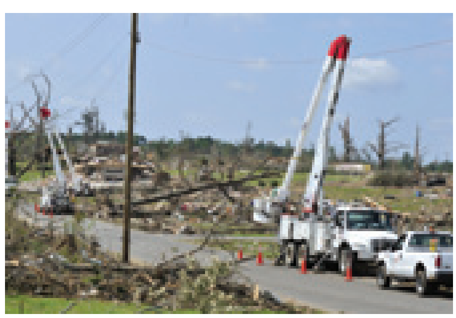
KML uses the three-dimensional geographic reference system of longitude, latitude, and altitude to describe a basic point of view in space over or on the surface of the Earth, then adds more specific control over that view with heading, tilt, and roll factors.

Particularly useful to utilities is that KML offers the ability to add text information, graphic overlays, 3-D polygons, paths, icons and add embedded files (images or auditory) to enhance the experience of the geobrowser applications.

If three meters under a common switch indicate an outage, the system is smart enough to know every meter under that switch is out. As more incidents are added, the system analyzes the outage data and generates an outage-prediction location. It also organizes and analyzes recorded incidents to predict whether a string of outages are connected to a larger outage at a substation, fuse or breaker.

But while an OMS can estimate where service is out, it can't necessarily reflect where service is back on – or more importantly – what locations could actually take power. That's where the integration with AMI comes in.

For example, let's say there are 500 residences connected to one switch. Alabama Power can know the switch is open either through the SCADA system indicating the switch open or by pinging the affected meters. But if the switch is closed, the utility can't know the status of those 500 customers. Following the storm, so many structures were damaged or destroyed from the tornadoes, restoring service wasn't immediately possible in some areas. Available meter data was able to provide enough clues to give us the information about individual premises that the legacy OMS couldn't.



Smart meters send real-time alerts, the so-called "last gasp" to signal outages in many cases, sooner than customers can call the utility to report the outage. With these messages, the OMS can specify critical loads; typically hospitals, fire stations or traffic signals for priority restoration.

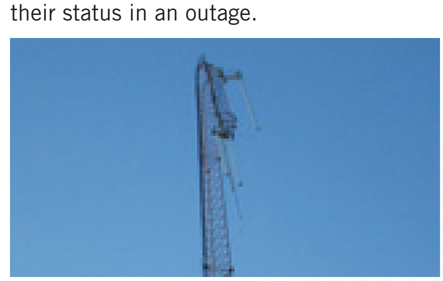
In the storm's aftermath, the question was, "Can a given premises take power?" With the AMI system integration to OMS, you answer this question with another question, "Can I or can't I talk to the meter?" Alabama Power began generating reports listing meters that couldn't be reached with the correlating data fed into a KML (Keyhole Mark-Up Language) generator for displaying outages geographically in a Google map.

These reports were updated throughout the restoration process for storm responders, but the information was also used by marketing personnel to confer directly with large customers as well as accounting staff to track service orders necessary for disconnecting power at structures wiped away by the storm. Communicators used the data for regular news updates that kept the media and customers informed on the restoration progress.

Network Stays Intact

Durability in a storm situation was a significant, but not deciding factor in selecting an AMI technology several years ago, but no one at Alabama Power could have anticipated the magnitude of destruction from the storm that hit the southeast that day in April. Notably, tornadoes were originally seen as less of a threat than hurricanes.

An important consideration in selecting the fixed-based, point-to-multipoint AMI solution was that it required far less infrastructure, reducing exposure to damage. Thousands of miles of transmission and distribution lines and structures were lost in the storm, which would have left alternative communications systems vulnerable because downstream meters, dependent on alternative hopping scheme, may not be able to communicate their status in an outage.



AMI Extends Alabama Power's Outage System Effectiveness in Historic Storm

Alabama Power has a total of 150 antennae towers throughout its service territory, communicating point to multi-point with about 1.48 million electric meters. Some of the towers are also co-located inside distribution substations. The network remained largely intact after the storms blew through, save for one tower that had the top 40 feet bent down 180 degrees towards the ground. The antenna from the crippled tower, however, was still transmitting a signal. Moreover, Alabama Power can supplement a loss of signal from a damaged tower (or down due to scheduled maintenance) with a mobile tower unit from its inventory.

Each TGB (tower gateway base station) collector has battery back-up, and some also include an emergency generator. Battery backup of the TGB collectors allowed Alabama Power to know what happened in the immediate aftermath of the storm, including which TGBs didn't have power. These were given priority for restoration.

Aftermath

Eight days after the storms, on May 4th, Alabama Power reported that most of the critical infrastructure had been repaired. In all, 412,000 customers were without power at the peak of the storms. More than 5,200 poles and more than 400 transmission system structures were damaged or destroyed. In addition, more than 300 substations lost power and six substations were either destroyed or suffered significant damage. At least 10,000 customers could not take power because of severe damage.

It was later learned that Alabama Power's service territory alone experienced more than 30 tornados covering more than 690 miles. The National Weather Service determined the path length of one tornado that devastated Tuscaloosa, Pleasant Grove and parts of Birmingham to be 80.3 miles with a maximum damage path width of 1.5 miles. The tornado's most intense damage indicated peak winds of around 190 mph. Reports from Tuscaloosa indicated 43 people were killed, with over 1,000 injured. Overall the tornados of April 27th killed 243 people.

Obviously, the human toll puts this entire episode into perspective. However, with 10,000 utility personnel working around the clock and a robust technology infrastructure, Alabama Power was able to safely restore most service in a relatively short period of time, especially given the extent of the devastation.

A Winning Combination

With the OMS and AMI combination, the utility could ensure power was on without having to dispatch personnel. This allowed restoration work to be prioritized for the most affected areas and slowly bring daily life back to normal. The storm hit on a Wednesday, closing schools for the remainder of the week. When school system officials wanted to know if they could open on the following Monday, Alabama Power could quickly communicate to all the meters on school buildings ensuring power was on and confirm that they were safe to reopen.

When feeders were rebuilt and placed back in service, AMI feedback from individual accounts could relay the status of individual premises on the feeder to the OMS system, making a call or dispatch to the location unnecessary. Meter data could also be graphically displayed to understand the level of damage and help prioritize recovery operations. Additionally, it helped personnel estimate with some degree of accuracy the number of premises that were no longer able to take service because of storm damage.

Most service was restored two days faster than what had been experienced in the region's worst storms up to that point, including Hurricane Katrina in 2005. While it would be difficult to quantify how much the AMI system contributed to the speed of restoration, there's no question that it was a contributing factor to effective response management by continually presenting an up-to-the-minute illustration of the effects of what is likely to be Alabama's storm of the century.

About the Author

Derl Rhodes is AMI Network Operations and Translation Team Leader for Alabama Power Company. He is responsible for AMI network design and operations, new metering technologies, field applications for metering, support functions at Alabama Power, as well as communications systems for metering and various other Southern Company initiatives.

Critical Factors for Updating Legacy Systems: The Case for Alabama Power

By Robert Shively, CEO, Metadigm Services
Reginald Murchison, Manager of Metering Services, Alabama Power

Alabama Power Company – a Southern Company subsidiary – recently worked with Metadigm Services to design quality best practices and engineered solutions from pre- to post-AMI deployment. By leveraging the contractor's experience and research, Alabama Power replaced 1.4 million meters three months ahead of schedule. This article shows how meticulous planning and employing quality best practices help to ensure that smart metering systems go in smoothly, and once installed, work accurately, safely and correctly throughout their useful life.

Today, more than half of all states have smart metering legislation or policies in place, and utility companies across the U.S. are updating their legacy systems to adhere to mandates that are either already in place or soon to take effect. However, utilities oftentimes underestimate the complexity of AMI deployment; that is, recognizing the importance of quickly, efficiently and accurately carrying out deployment as the key to a successful project overall.

The Alabama Power Company (APCo) business case indicated that by completing the project early, the utility would be able to drop all manual meter reading efforts earlier than originally planned, saving significantly on the associated labor costs. Completing the project early also allowed APCo to redirect management and other project resources to focus on other aspects of their business also in need of such support.

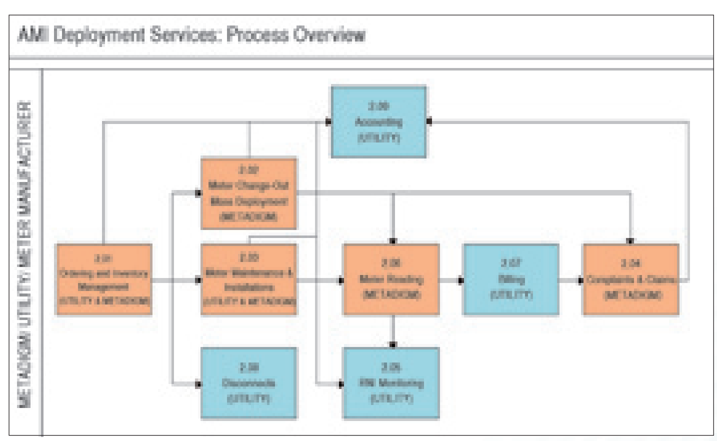
The main objective was to replace the meters, but the task was actually more than just a meter exchange; successful deployment is also about building sustainable practices and long-term relationships. Moreover, APCo had several objectives that went well beyond simple meter installation, which included cost reduction; having more accurate load and outage data; cleaning up bad connections in the meter bases; finding overloaded transformers, and more. Thus, the project also involved working out logistics, testing, warehousing, IT management and billing.

Overall, the most common reasons among utilities for pursuing AMI deployment include cost reduction, more accurate load and usage data, improved outage response and peak demand management. In order to achieve a successful full deployment, several key factors must be considered, two of the most important of which are strategy and planning.

Strategy and Planning

APCo made the decision to upgrade its metering systems to AMI in 2008, the first phase of which was to createan AMI deployment plan. Deploying a large-scale meter implementation involving well over a million meters, required a detailed and comprehensive blueprint before any physical deployments could begin. Having worked previously with multimillion meter projects, best practices derived from lessons learned were transformed into an AMI deployment playbook developed specifically for Alabama Power.

Moreover, as utility companies across the nation upgrade customer meters, it is important to keep in mind that projects at their core, smart meter deployment initiatives are fundamentally technology deployment projects. Among other things, this means that databases and a wide range of digital parts and accesssories must often deploy concurrently with physical meter installations. As a result, there is a huge amount information to absorb, making this type of detailed planning and guidance a key ingredient in any successful project.



This excerpt from the "Project Playbook" shows various process relationships for a typical AMI project.

Nearly eight months before APCo's installation began, the Metadigm team began working closely with various departments within the utility. These included operations, customer service, billing and IT. Over time, a full AMI deployment touches nearly every department within the utility organization. During this process, key contacts at Alabama Power were provided with a job-specific procedure list for each event that would occur before any work started.

The value of precise planning cannot be overstated: In the initial planning phase, Metadigm led a process to verify smart meter functionality in the field. Then, working with the APCo staff, conduct a field test was conducted to verify that the measurement on the internal micro-transceiver matched the measurement displayed on the outside of the meter. This type of assessment obviated the need for revisiting a site to confirm the accuracy of the new meter, and more importantly, prevented any inaccurate and/or inconsistent meter readings.

Warehousing and Inventory Management Keep Project On Track

Warehousing and inventory management are more than just receiving, storing and deploying meters from a centralized location. Proper management represents the foundation for a successful AMI deployment. As the project progressed, each of the following factors had to be carefully considered as part of a close working relationship formed at the outset of the project:

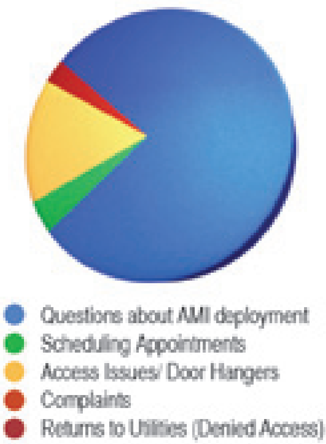
- Supply chain management
- Shipping and receiving planning and coordination
- Offering available rack space in a dry and fully secured environment
- Tracking inventory from receipt of new meter to installation of new meter
- Reporting inventory on a daily basis
- Distribution of new meters for forward deployment
- Collection of used meters and security of used meters
- Salvaging of used meters

The first three regions were completed from one centralized warehouse, subsequently moving the operations according to the schedule. Notably, being able to operate several satellite warehouse operations helped to complete the project much faster than expected. And by moving the warehouse locations, technicians working in a centralized area could maximize the field installation and testing efforts. For example, when the schedules changed on short notice – often due to regional needs – temporary warehousing was set up to allow the installation crews to be dispatched out of a localized area.

Maintaining warehousing kept the project on-track without any interruption to forward deployment. This operating method provided quick problem resolution and saved money, in part by eliminating the need to ship meters back to the manufacturer before being redirected.

Full Deployment Requires Full Communication

Alabama Power and Metadigm worked together closely to develop a robust internal communication plan to educate Alabama Power's employees about the project. Moreover, Metadigm trained each field technician on how to properly respond to customer questions and concerns regarding the work being done on their property and to keep the language and conversation positive, informative and pertinent.



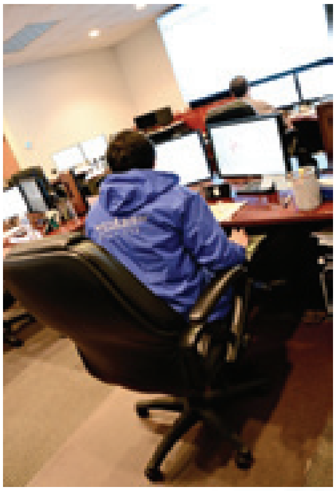
Metadigm field technicians represented Alabama Power on each customer's doorstep, making it vital that they abide by strict safety requirements; are dressed and groomed appropriately; are equipped with the proper tools for installation and safety; can communicate their duties effectively; and can field any questions customers might have.

Being trained in what NOT to say can be as important as what TO say, so when customers needed to direct their complaints, questions or concerns to APCo, the contractor fielded those with a 24/7 virtual support team – much like having a "Fix It" button at their disposal.

Data Management Expertise

As most utilities are well aware, accurate billing depends on accurate data collection and management. If the last bill was incorrect, revenue may be lost forever. Accurate data is what AMI is all about.

Alabama Power provided historical billing data for each customer well in advance of meter deployment, which was used to compute an expected meter read for each work site. By using discrete data points like this, multiple verification steps were able to be performed as an integral part of the meter change-out process.



Network operations center where data analysts run automated daily audits for all completed work.

All data collected must then pass through the contractor's network operations center where automated analytics perform multiple verification checks for all completed work records. This analysis provided a 100% audit that resulted in quality billing data being delivered to Alabama Power each work day.

A True Partnership

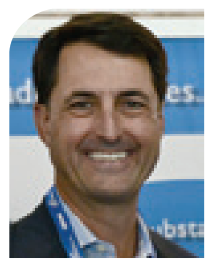
Metadigm's development team worked closely with Alabama Power pre-deployment and worked side-by-side with Sensus Metering Systems – APCo's smart meter provider – to integrate Metadigm's handheld units with the Sensus meter verification unit. For both companies, being flexible was a must. Several situations arose causing the teams to work a creative solution in a short time. Being flexible and able to ramp up the necessary field forces quickly, Alabama Power Company's needs were met on short notice, but without sacrificing quality, workmanship and attention to detail throughout the project.

This close working relationship – built and strengthened throughout the course of the project – created a firm foundation that also helped lead to a successful deployment. Moreover, the importance and value of having a partner that will work to correct any problems or challenges that arise; quickly and effectively respond to complaints; and can work effectively with Alabama Power's customers to form a true and lasting partnership was clearly a critical ingredient in the overall success of the APCo project.

About the Authors

Reginald Murchison is Manager of Metering Services for Alabama Power Company, a subsidiary of the Southern Company. Reggie has responsibilities for the design, development and application of revenue meters and meter systems, including residential, commercial, industrial, substation/transmission metering, and AMI systems. He is currently the 1st Vice President of the EEI Metering Committee and the past Chairman of the AEIC Meter and Service Committee.

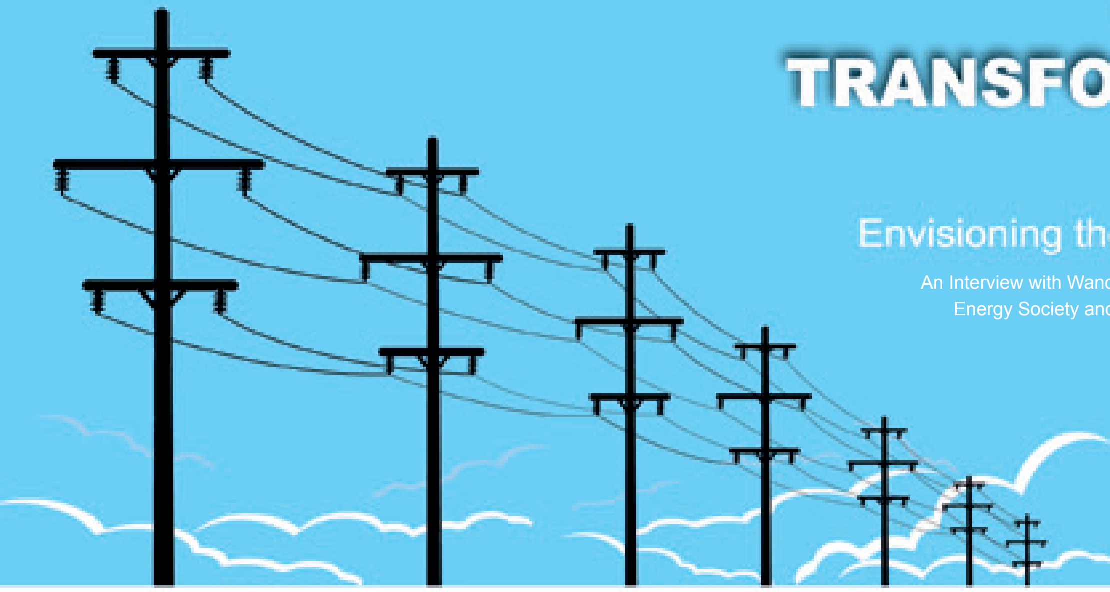
Reggie has over 31 years experience in the utility industry at Alabama Power Company in the areas of power generation, marketing, power quality, distribution support, human resources and for the past ten years in metering. He holds a BSEE from Tuskegee University, MSEE from the University of Alabama in Birmingham, and a MBA from Samford University (Birmingham, Alabama) and is a registered Professional Engineer in the State of Alabama.



Robert Shively is President and CEO of Metadigm Services. He envisions an aligned energy infrastructure – one that links power generation to power consumption in real-time. According to information from the EIA, over half of the electric energy produced today is lost. Shively is leading a charge to better manage utility assets in order to more fully utilize this country's energy supply in real-time through intelligent metering, monitoring, and proactive maintenance.

Before forming Metadigm Services, Shively was president of SM&P Utility Resources, a division of Laclede Group that specialized in underground facilities. Under Shively's leadership, the company increased revenue from $85 million to $170 million, which also raised shareholder value $155 million.

Shively earned his M.B.A. from Duke University's Fuqua School of Business and a Bachelor of Arts in economics from Furman University. He serves as a board member for Area Wide Protective, a utility services company owned by Blue Point Capital Partners and is a frequent presenter and educator on the topic of intelligent asset management for utilities, municipalities, and co-operatives.



THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

An Interview with Wanda Reder, Past President, IEEE Power & Energy Society and Vice President, S&C Electric Company

EET&D: As another year is starting, the Smart Grid continues to open up new opportunities for innovation in what has historically been a very traditional and relatively slow-moving industry. With that perspective in mind, I'd like to begin by asking you about the role of innovation in the long-term Smart Grid picture, and more specifically, where you expect to see innovations taking place in that future evolution.

Reder: Fundamentally, industry transformation is occurring largely where communications and computational systems are converging with traditional power systems. As we evolve toward a smarter grid – and I do mean smarter because the grid has a huge component of intelligence already – we're learning how to apply technology to a power system that has become very complex over the past century.

For example, in 2000, the U.S. National Academy of Engineers rated the electric grid as the major engineering accomplishment of 20th century. We've been installing technology and routinely increasing the level of intelligent operation for decades, and that isn't going to stop now. However, as computational and communication technology continues to evolve and expand, it is being applied to the grid so that we can run cleaner, more efficiently, and more reliably. In the most basic terms, that's where a lot of the innovation is coming from; that is, the convergence of various technologies and disciplines required to deliver the kind of grid performance, safety and reliability necessary for the digital economy of the 21st century.

EET&D: What are some of the other elements that are fundamental to Smart Grid, and to what degree are consumers involved in the equation?

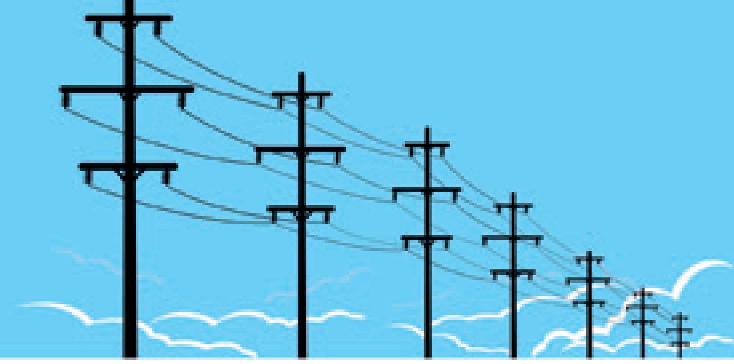
Reder: The power system we have known for the past fifty years or so was built with centralized generation that ebbs and flows to accommodate consumer's electrical needs. In the future, in the modern grid – the Smart Grid, if you will – consumers will be empowered to make informed choices, depending on price signals and other behavioral factors. In addition, consumers and independent power producers are adding their own de-centralized – and sometimes highly intermittent – generation sources connected at various locations along the delivery system. Collectively, these are adding new dimensions of variability and uncertainty, which in turn, are leading to new operational paradigms. And, at the center of it, is the impact of consumer's choice.

EET&D: How is the innovation taking place today different from say, a decade ago?

Reder: I think there are several facets of innovation that are quite different today. These fall into three main categories: Improved technology, where cost-effective energy storage is a power system game changer; a new element of interest in privacy and cyber security; and much broader stakeholder interest requiring engagement early and often to move innovations forward.

There is a lot of innovation in battery technology now that allows us to store power during periods of low demand and use it when the demand is the highest. In addition to managing these peak load conditions, batteries can help to defer equipment upgrades, improve service reliability, reduce losses and even help regulate frequency and voltage.

EDITOR'S NOTE: Portions of this interview are based on, and adapted from, a previously taped interview with Ms. Reder that was prepared by the IEEE Power & Energy Society and is used here with permission.



Historically, it has been very costly to store electricity in any practical way, but that is changing. New batteries and other storage technologies are adding new and innovative elements to the grid that was only being talked about a decade ago. This new wave of innovation is changing the very essence of how we think about power systems, which is now morphing into a completely new architecture – one with multi-directional power flow and substantially increased two-way communications, especially at the distribution level.

Another area that was barely on our radar a decade ago involves data privacy and cyber security issues. New rules around sharing information, securing communications and protecting systems critical to the nation's security and economic interests have emerged and are now a mandatory consideration for innovation. Furthermore, as standards and requirements continue to evolve, new technology needs to be easily upgradeable to ensure compliance.

Finally, I think the process to ensure acceptance of new technologies is much more involved than it was a decade ago. A broader set of stakeholders needs to be consulted to generate support and approval. The stakeholders can include consumers, regulators, utilities and even contractors and support organizations. Engaging them with a transparent process early and often will help move innovation forward while also building on existing know-how and accepted practices.

EET&D: What do you feel is the most important message about Smart Grid that needs to be communicated to the marketplace?

Reder: Smart Grid can only succeed if it's rooted in deep customer engagement, allowing consumers to better understand the benefits of their involvement and ultimately, help manage their energy use and resultant costs. This engagement can start by conveying the importance of Smart Grid for consumers to make proactive energy choices that help facilitate sustainability. Until now, electric bills have been largely an afterthought for most consumers, but Smart Grid initiatives dramatically change that dynamic with the onset of real-time usage data, alternative pricing schemes and the advent of more recent innovations like plug-in electric vehicles and distributed generation.

In addition to consumer engagement, we also need better messaging across the various technical disciplines that are involved in Smart Grid development. I feel that IEEE can really help make a difference by bringing interested, but divergent technical audiences together to vastly broaden their understanding of various technical disciplines. We can build awareness about each other's challenges, bring best practices to the table, and as a result, be much more proactive and effective in educating the marketplace at large about the Smart Grid.

The fundamental message we need to get across is that there are many ways to provide energy that's cleaner, more efficient, safer and more reliable, but it all requires grid modernization. Fortunately, Smart Grid technologies are ready to deploy today that can allow us to do a much better job in the future.

EET&D: Clearly we've been in a tough economy the past few years and it would seem that full recovery will take more time. Is economic recovery an issue for the Smart Grid?

Reder: Yes, and inevitably, it will be a long evolution for many reasons, not the least of which is cost. The good news is that we already have most of what we need to get the job done, but the will to employ that technology has been lacking in many ways. Consumers want low rates, but they also want a sustainable model with the kind of reliability that we have enjoyed and to which we have become accustomed-- all of that comes at a price.

EET&D: Does that mean that the grid has to be entirely redesigned and/or replaced?

Reder: Let me answer this way: When we think about the infrastructure that has been built to have our lights come on when we flip the switch, we must also remember that our infrastructure has been a work in process for the past 100+ years. That is, when you really think about what it takes in terms of power generation, transmission and distribution to make it operate is really quite amazing, yet most of us just take that for granted, even though it wasn't free and it certainly did not happen overnight. Likewise, the Smart Grid will not happen overnight either. Intelligence, increased control and system upgrades will be added to the original grid, resulting in modernization and benefits over a long period. Therefore, the investment will take time, and the grid will be partially replaced and re-designed using new technology.

EET&D: What are your thoughts on how we will get from where we are today to where we need to be a decade from now?

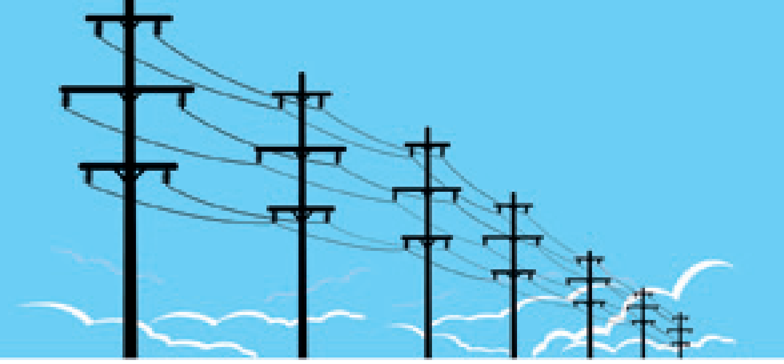
Reder: First, our aging infrastructure needs to be modernized, and I certainly hope that we go about it in a way that's smarter than just replacing it in-kind. Moreover, every state is in a different place when it comes to the grid and its legacy infrastructure; every utility and its relationship with state regulators is at a different place, and there are varied objectives from country-to-country. That means that it will be very difficult to formulate uniform answers or be able to make broad, sweeping statements as to priorities and the rate of deployment in any given region, state or country. Some companies and regions are certainly moving ahead faster than others, but the applications resulting in the highest benefit for the least cost are going to be deployed first, while others will inevitably take longer – and in some cases, much longer.

EET&D: So many aspects of Smart Grid seem to be developing simultaneously: Electric vehicles, smart metering, renewable energy, and the list goes on. Is the order in which these things will take place based purely on economics, available technology or regulatory issues?

Reder: There are whole ranges of variables that go into that equation, and again, depending on the application and the situation, it's really going to vary widely across the various regions and individual utilities. For example, some situations are constrained by transmission congestion that must be alleviated before a large penetration of renewable integration can take place. In other cases, utilities may be satisfied with their generation mix and instead, focus on updating metering infrastructure and the consumer interface.

Furthermore, initial electric vehicle sales will likely be focused in larger cities, and adoption is likely to occur in community pockets, making the challenges associated with charging stations somewhat isolated in the short term. Therefore, the electrical needs and the regulatory climate both vary, causing the natural order for deployment to fluctuate, depending upon the circumstances in each geographical region.

EET&D: Lately we've heard a lot about renewables and how important they are to our energy future. Do you feel that renewables are now with us to stay?



Reder: As we project future generation supply and demand it seems certain that renewables will be a big part of that mix – as they already are in some countries and regions – but we need to stay focused on doing it in a way that is both reliable and sustainable.

EET&D: What about the distribution side of the grid – what measures or steps are being taken there?

Reder: When it comes to distribution, we really have to focus attention on managing peak loads effectively, managing losses and providing reliable service that accommodates the needs of the new digital economy. The penetration of consumer electronics, computers and other electronic gadgets is increasing rapidly, and the demand for near-perfect power quality and uninterrupted power availability at the distribution level is increasing right along with those trends.

Secondly, the load factor in the U.S. has been in steady decline since the early 1960s. Today, peak conditions are actually occurring only about 1% of the time during a year, yet we have built the system to accommodate peak load during those periods. Thus, total capacity is being grossly underutilized most of the time. Furthermore, capacity investments have been lagging the growth in peak load, making the system vulnerable and difficult to operate during peak conditions.

Finally, there is a lot of loss in the power system. Excluding generation, we can lose as much as 15% of the power from the time it is generated to when it is consumed, so we're taking pro-active steps to better manage the peak, build in automation to improve reliability and implement control schemes and technology to reduce losses.

EET&D: What are the chances for improvement in these areas?

Reder: Overall, we need to make much more efficient use of the entire generation, transmission and distribution infrastructure, and ask ourselves some probing questions: Can the grid be reconfigured to make use of new battery storage capabilities? Can incentives be provided to encourage consumers to make choices that improve energy usage patterns? What more can we do to deliver power more efficiently, more reliably and still get the most out of the infrastructure that's already deployed?

Technology deployment is likely to be where the process begins, but it's definitely going to take longer to appropriately and effectively engage the consumer. Behavioral change is usually slower than technological change and advancement, so it will take time and probably some retries – and of course, consumer engagement and education – to achieve those objectives.

EET&D: What kinds of storage are required for the digital grid, and what work is already under way to address those requirements?

Reder: There's a lot of new investment in storage right now, but it's not as if we haven't had storage built into the grid before. Hydro plants have been used as a storage mechanism for a long time, and in some places, we use hydro plants to offset other types of generation. Now we're starting to look at different types of storage technologies coming into play like compressed air, flywheels, ice storage, ultra-capacitors and numerous battery types such as lithium-ion, nickel cadmium, sodium sulfur and flow batteries. The characteristics of the storage technologies vary and the applications have a very wide range that continue to expand as technology moves forward.

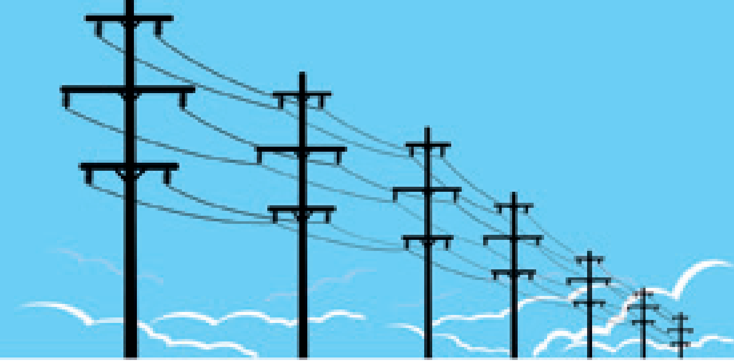
EET&D: Are there any practical installations of these new types of technology?

Reder: There's a 4-megawatt installation in Texas that provides up to six hours of power for an entire city. The city's primary power source is a long transmission line, which is frequently struck by lightning causing repeated electrical problems. The original backup source required a lot of switching time and was fed from across the border in Mexico. To mitigate the potential of having repeated and extended outages at this border town, they've backed up the whole thing with battery storage.

Batteries are also being brought to the community level in the form of community energy storage where it is connected on the low-voltage side of the customer's transformer to help accommodate plug-in vehicles and handle the variable effects of solar panels. Community energy storage can provide the ability to shave the peak, smooth the load profile, manage voltage fluctuations, and improve service availability. In addition, with numerous units deployed, a control scheme can aggregate the operation of all units to effectively create another distributed generation source.

EET&D: What, if anything, can be done to better integrate renewables into the grid?

Reder: The challenge of renewables, such as wind and solar generation, is that they are intermittent and occasionally require high-speed reactive compensation to successfully connect to



the grid. With solar, when the sun goes behind a cloud, the flow of energy being generated by the panel is interrupted and then returns when the sun comes out again. When that happens, the solar source turns on and off very quickly. It doesn't make a big difference in overall power generation, but the intermittent interruption of the generation source can be problematic for grid stability. This is also a typical scenario for wind generation, since the wind doesn't just continue to turn wind turbines at a steady rate 24/7.

To aggregate and integrate these intermittent resources into the transmission system, a buffer to mitigate that intermittency is useful. Flywheels have proven to be useful for stabilizing the network, which allows renewables to be more readily and consistently integrated into the grid.

EET&D: Looking at the near-term, are you anticipating any milestones or achievements within the next couple of years relative to the issues and trends we've discussed today?

Reder: Over the next couple of years, I believe those that have started down the Smart Grid journey will continue to do so while incorporating lessons that they have learned internally and from others. As successes are reported, stakeholder confidence and acceptance will generally increase and business cases will strengthen, both of which will accelerate the rate of adoption. Regulator models will also evolve to better embrace grid modernization. This evolution is vital toward providing assurance that there is a long-term regulatory commitment to Smart Grid strategy and that a mechanism to get a return on the investment will be there.

We will also gain a better appreciation of the importance of a Smart Grid to satisfy the electricity demands of this century and its connection to sustainability and economic viability. Within the next two years, I believe we will have greatly improved our messaging and become much better at engaging the consumer in the overall process. Finally, there's a lot of room for operational improvement as we move toward adoption of Smart Grid technologies and change our traditional operating paradigms accordingly. Smart Grid is a journey that is in the process of unfolding in 2012 and will continue well beyond.

GREEN OVATIONS

Innovations in Green Technologies

By Pritesh Gandhi, CEO of Ambient Devices and
Ahmad Faruqui, Principal at The Brattle Group

It's a well-known fact in today's society, information equals power. Without information, the ability to make educated decisions about what to do and when to do it is hindered. This applies to all aspects of our work and life – and now it is beginning to impact the way we consume energy...

Clearly the statement above is a phenomenon that most utilities understand well and grasp the potential benefits of. Utilities across the country have embarked on Smart Grid projects that promise the possibility of providing this 'power' to consumers; however, the effects of these efforts are not being immediately realized and the consumer is far from feeling empowered. In fact, in some cases Smart Grid projects have provoked fear and confusion amongst consumers rather than instilling a sense of empowerment. The massive investment in infrastructure upgrades and technology to drive the Smart Grid is being called into question due to the inability of utilities to communicate precisely how these technologies will empower consumers to make better decisions.

Readers of this article are arguably part of the most informed set of the population as regards Smart Grid issues. However, for the general public, industry terms such as 'demand response' and 'load balancing' are foreign concepts and require significantly more explanation before they make it into mainstream conversation, let alone into meaningful changes in behavior. Tools that provide simple accessibility to information will be the strongest aid for these programs to have a lasting affect on consumer behavior.

Energy Monitoring Moves Into the Living Room

Historically, the traditional interactions that utility companies have with consumers are limited to two instances: (1) when the consumer gets their monthly bill and (2) in the event of a power outage. As the Smart Grid roll-out becomes a reality, utilities are adding to the touch points of information they are gathering from and delivering to consumers.

Electric meters – smart or not – provide very accurate information in precisely the wrong location. Most homeowners often go years without actively noticing their meters – because there has never been a need to do so. In-home displays (IHDs) hold the promise of bringing this information into the environment where the consumer actually makes decisions on how to interact with their energy consumption. Transitioning to a world where IHDs are prevalent and deliver the promised benefits requires utilities to focus on what works. Several factors determine what works and what doesn't, as summarized in the paragraphs following...

Affordability **is an important factor involved in ensuring a broad adoption of IHDs.** Ideally, the devices are made available at no up-front cost to all consumers. There has been an aversion by US consumers to spend discretionary dollars on energy saving products and services. Whether via subsidies at retail or direct distribution, utilities need to work with manufacturers of IHDs to provide a cost effective solution that has the broadest consumer appeal. For manufacturers, this means focusing on the core functionality and building features into devices that are sure to provide tangible value to the consumer.

In-home displays must be *simple to install.* It is beyond the resourcefulness of most consumers to ask them to replace their existing thermostat or access their electrical panel. Requiring a professional installer is not only inconvenient for the consumer, but also defies the rule of being affordable. The devices have to be 'plug-and-play' and work without an intense study of a user manual.

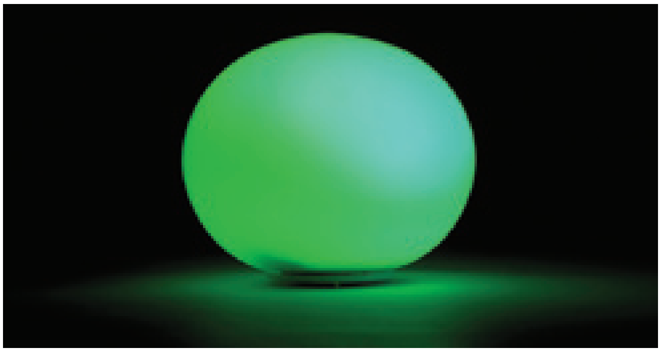
The data presented on IHDs should be intelligible. Kilowatt-hours are not part of our daily vernacular and most consumers would have a hard time translating what this means. Data should be made available in metrics that are widely understood – dollars and cents vs. kilowatt-hours.

IHDs should be *glanceable*. The display should represent the most important information in a form that can be read from across the room in less than a second. This highly summarized view of information enables consumers to process all the data they need to know and what to do with it at a glance rather than digging through multiple screens or graphs. 'Glancablity' allows for simple explanation on the function of a device to any consumer. Any 'drill-down' information, meaning detailed descriptions of the data, should be presented by actively engaging with the device or on a separate screen such as a smart phone or web-browser.

The data shown on any IHD should be *dynamic*. Displayed data should change often enough to remain interesting and instructive to the consumer. This not only makes for a more engaging experience, but also helps build a trusted relationship with the device because consumers are apt to react to it more often.

It is important for IHDs to be *situated* appropriately. The display should be positioned properly in order to provide information at the decisional moment of energy consumption. Smart phone and web browsers offer rich displays of data, but often not where consumers are making choices on how to use energy. The IHD can be placed virtually anywhere in a home, allowing consumers to position the device in the periphery of our senses in order to provide continuous information without being distracting.

IHDs must be *unavoidable*. It is necessary for the display to cut through the visual clutter of the home to promote mindfulness around energy use. It is important that they are designed not to mimic other devices in the home, but stand out amongst the vast array of screens that in consumers' homes today. This is perhaps the most important element that will lead to the success of an IHD deployment. The device must also endure the possibility of being placed in the 'junk drawer', a place where many other gadgets end up.



Energy Orb glows varying shades of color representing energy consumption and demand on the grid

Baltimore Gas & Electric Tests the Energy Orb

Ambient Devices recently introduced the Energy Orb to address what works for utilities and their customers. The device's imbedded intelligence and network connection enable real-time feedback from the energy grid, which directly affects the users energy consumption behavior. These devices have been deployed by over a dozen utilities in both residential and commercial demand response projects worldwide to show the load on the grid, manage demand and avoid brownouts.

In the summer of 2008, Baltimore Gas & Electric Company (BG&E) embarked upon a unique experiment designed to understand how customers would respond to a variety of smart grid stimuli. Called the Smart Energy Pricing (SEP) pilot, it ran from the beginning of June through the end of September. It tested two types of dynamic pricing rate (critical-peak pricing and peak-time rebates) and two types of enabling technologies, the Energy Orb and switches for cycling central air-conditioners.

Since the SEP pilot was focused on measuring changes in customer behavior, it was designed in conformity with scientific principles of accurate measurement. It featured a variety of matching treatment and control groups that were randomly selected and their load profile was measured before and after the introduction of the smart grid treatments. Altogether, 1,375 customers participated in the pilot. Of these customers, 354 were in a control group, 401 on dynamic pricing rates without enabling technologies, 278 on the Energy Orb in conjunction with dynamic pricing and the remainder on the Energy Orb and cycling switches for central air conditioners.

Customers in the control group stayed on standard rate, which charged 15 cents per kWh around the clock. Those on the critical-peak pricing rate faced a price that was nine times higher on the peak period on a dozen days that were designed to simulate very high price conditions in the PJM wholesale market. Prices during off-peak hours were about six cents per kWh lower than the standard rate. Two types of peak-time rebates were tested, featuring levels that were nine times higher and twelve and a half times higher than the standard rate.

Econometric analysis of the experimental data yielded some remarkable insights. Customers on dynamic pricing without enabling technology showed the same pattern of price responsiveness whether they were on critical-peak pricing or peak- time rebates. On average, they lowered their usage during critical-peak periods by 19.6 percent.

When they were equipped with the Energy Orb, their price responsiveness went up to 24.9 percent. It is noteworthy that the Energy Orb did not control any appliance in the home, like the cycling switch, but it conveyed actionable information a meaningful and simple way to the human mind. Furthermore, when the cycling switch was added to the Energy Orb, the responsiveness went up to 30.4 percent.

In sum, the SEP experiment showed the power of dynamic pricing, especially when carried out with information-conveying technologies such as the Energy Orb. The experiment also addressed the major variables in changing a customer's energy consumption behavior:

- Affordability – Participants in the BGE pilot were provided with IHD's free of charge.
- Installation – The IHDs were simply mailed to the consumer's home via regular mail delivery and were able to receive real-time data ten minutes after being plugged into the outlet.
- Intelligence – Instead of showing a vast amount of data, the IHD only displayed colors to represent the data.
- Glanceability- Data was presented through varying shades of color representing dynamic data that could be absorbed at a glance.
- Dynamic data - During the pilot, data was called throughout the summer allowing the IHD to maintain relevance.
- Location – Participants were able to position the device where they were able to gain the necessary information at the decisional moment of energy usage.
- Design – Unlike many other smart IHDs, the Energy Orb is designed to stand out amongst other devices in the home.

The plug-and-play orb can be setup anywhere in the home, allowing consumers to easily view the dynamic information they care most about without having their everyday lives disrupted.

Utilities Must Communicate

IHDs serve as a communicative approach for utility companies to relay information to customers about energy consumption and demand. By establishing a relationship, utility companies can forewarn their customers that supply and demand on the electric system may be reaching a critical point or that a demand response event has been called. By outfitting consumers with an easy-to-use enterprise or in-home tool for smart energy consumption, utility companies will see power spread more evenly through each day and consumers will begin to shift their usage to off-peak hours, resulting in relief for the grid and energy bills.

About the Authors

Pritesh Gandhi is CEO and Co-founder of Ambient Devices, Inc. in 2001 and serves as Chief Executive Officer. Mr. Gandhi has more than 15 years of experience building companies focused on delivering innovative consumer applications across multiple industries. In addition to overseeing Ambient Devices operations and strategy, Mr. Gandhi has been the driving force behind the company's expansion into the In-Home Display market. Through his direction and management of Ambient's retail partnerships, he has brought over one million units to the shelves of retailers including Best Buy, WalMart and Brookstone.

Mr. Gandhi received his BS and MBA from Boston University, where he concentrated in Marketing and Entrepreneurship. While pursing his MBA, Mr. Gandhi wrote the business plan for Ambient Devices and co-founded the company shortly after graduation.

Ahmad Faruqui is a Principal at The Brattle Group and one of the nation's leading experts on the smart grid. He helps clients assess the economics of dynamic pricing, demand response, advanced metering infrastructure, and energy efficiency. He pioneered the use of experimentation in understanding customer behavior and his early work on time-of-use pricing experiments is cited in Professor Bonbright's textbook on public utility rates. The author of four books and more than a hundred papers on energy policy, Faruqui holds a doctoral degree in economics from the University of California at Davis.

Bridging the Consumer Divide with Smart Meter Data

By Mike Harris, Chief Executive Officer Zonoff, Inc.

For utilities, the electric meter is the gateway to the customer, both figuratively and literally. Beyond supplying a reliable and consistent life-essential commodity, the electric meter can also supply valuable data, which can turn into actionable knowledge that can greatly benefit consumers. And with a wealth of intelligent, connected devices now filling the consumer's home, the opportunity has never been greater for utilities to help their customers in this new era of the Connected Home.

But there's a problem: The bulk of smart meters use the ZigBee wireless standard while more and more devices inside the home which control climate, lighting, media, communications and security are largely based on the Z-Wave wireless protocol. That disconnect in standards has left utilities in an unenviable position. They've spent considerable time and money to deploy large numbers of smart meters, but those meters can't connect with the growing number of intelligent devices and appliances inside the house.

Smart Meters – Not All That Smart?

For utilities, getting to the appliance or device level data inside the house can open up significant partnership opportunities with customers to help reduce overall load and smooth out peaks load periods. Studies have shown that customers are eager to get a picture of their total energy use, and how their actions affect it – provided, of course, that the utility safeguards the privacy of their data.

The results of an effective collaboration can be significant. Providing customers with real-time energy use feedback at the appliance level can cut household energy usage by an average of 12% a year, according to a newly-published research review by ACEEE and the University of Colorado. And reducing energy consumption, particularly during periods of heavy use, is far cheaper than building new peaking plants or new transmission lines.

Without access to actual data about how energy is being used inside the house, however, utilities have struggled to find ways to provide customers with useful information. A new generation of interval meters collects data at hourly intervals, or even in some cases on 15-minute increments, providing a much more fine-grained picture of energy use than was available in the past.

Some utilities are trying to harness those data streams by teaming up with cloud-based centers that collect that data, aggregate it, and provide it to customers in a way that they can use. Typically, these programs can tell customers how much electricity they used in the current week or the latest billing period, and allow them to compare that with previous periods. Utilities are offering comparisons not only with a customer's own usage, but with that of other customers, allowing homeowners to compare their energy use with that of their neighbors.

The Real Prize: Appliance and Device Level Data

This more frequent interval data has also allowed utilities to experiment with time-of-day pricing, providing an incentive for customers to shift their usage out of certain hours of the day. All this data, however, is "whole house" data, and utilities are finding that these programs typically deliver only a few percentage points of reduction in energy use. For many utilities the jury is still out on whether they are cost effective or not.

For customers to really shift their usage, they need better information than whole house data. Without access to data showing the actual energy consumption of various appliances or devices inside the house, and with sub-metering individual appliances generally cost-prohibitive, some utilities are taking the approach of modeling – essentially guessing – what's going on inside the customer's house.

The modeling is generally based on assumptions from very fine interval data, sometimes down the to the second. A surge in power consumption in the middle of a hot summer afternoon, for example, can be assumed to be the air-conditioning unit powering up. These time-series simulations can provide a reasonable model of usage data, but it's still just an estimate. Customers tend to find this approach less than satisfactory, and want specific information that can be sorted by various criteria including (but not limited to) time of day, type of device(s), room by room, or even usage by individual family members.

The Ascent of the Connected Home

The result has been a level of frustration with smart meters. Utilities have aggressively deployed the new meters, spending tens or hundreds of millions of dollars in the process, and found they've gotten little in return for their investment.

The data that utilities need in order to get real value from these deployments, however, is available only a few feet away from all these smart meters utilities have worked so hard to roll out. Inside the home, the Z-Wave standard – a low-bandwidth wireless technology, which allows devices to communicate with each other – has been quickly gaining ground. To date, over 500 consumer items, from door locks to outlets to light switches to security components to thermostats, have been certified as compatible and compliant.

These devices can respond to the directives or even passive actions from a home's occupants, or from other devices, making the long-awaited Connected Home a reality. A single tap on a remote next to your bed can turn off all the lights in your house after you're under the covers, as well as lower the thermostat and make sure the back door is locked. When your children arrive home from school and type their access code into a compatible door lock, the thermostat can raise the temperature, the lights will come on in the kitchen and the playroom, and a text will be delivered to your cell phone.

After years of struggling to reap the benefits of smart meters, utilities can now integrate their whole house data into the overall Connected Home eco-system. And customers who choose to grant their utility access to their appliance level data can gain useful insights into their home's energy usage, regardless of the type of electric meter they have.

The result is a wealth of data that utilities can use to provide sophisticated home energy use applications to customers.

To date, most of the smart meters deployed by utilities have been based on the ZigBee standard, which have not been able to communicate with Z-Wave devices inside the home. However, a new generation of "bridge devices" enables virtually any electric utility meter - old or new - to communicate with any Z-Wave compatible device. Using Electric Power Research Institute (EPRI) and Universal Smart Network Access Port (USNAP) standards, these bridge devices enable ZigBee-based meters to wirelessly exchange data with Z-Wave devices, and can also be extended to communicate with other protocols as well, allowing them to communicate with a wide range of current and future wireless standards. Even older electro-mechanical meters can now be connected using bridge technology.

Next generation bridge devices can significantly enhance the value of utilities' residential demand response programs because studies have shown that customers are far more likely to change their usage behaviors if the utility can provide them with detailed data about their usage and related costs.

The Connected Home

Utilities which can access the appliance-level data found inside the home will not only have more satisfied customers, but access to a new world of business opportunities.

That's because the unprecedented level of intelligence now found inside our homes' devices is transforming our formerly brick and mortar houses into Connected Homes. Among the trends at play in this transformation are:

1. Consumers who are more and more comfortable with technology; who are used to using products such as Apple iPhones and iPads to control and enhance their lifestyles via user-friendly and intuitive interfaces; and expect to always be connected - both in and out of the home.

2. An emerging regulatory environment from both federal and state governments, where utilities (and even entire countries) are required to have better control over the generation, distribution and consumption of power in homes.

3. Powerful commercial players such as broadband providers, seizing opportunities to increase their average revenue per user (ARPU), reduce churn and become solutions providers rather than just "dumb-pipes." Broadband carriers AT&T, Comcast and Verizon have already unveiled product offerings for the Connected home.

4. Technological convergence with increasing focus on standardization and interoperability of wireless standards (i.e. Z-Wave, ZigBee, 802.11 Wi-Fi, etc.) while at the same time, the cost of electronic components and chipsets are trending down.

The Connected Home's Central Nervous System

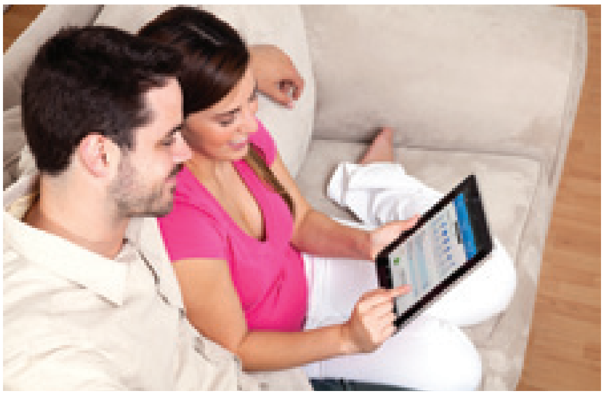
The concept of the Connected Home can seem daunting. It may be useful to think of analogy we're all familiar with: the human body.

The human body is made up of the digestive, respiratory, circulatory and other systems, and each of these sub-systems is made up of a series of organs. The digestive system, for example, includes the stomach, small intestine and large intestine, which can be thought of as "components."

The human body also has a series of "input sensors" – our eyes, ears, nose, tongue and skin, which are tied together with the body's other components and sub-systems through a central nervous system, which serves as the "network" for our body, carrying critical, real-time information to the human brain - our "central processor."

All these systems work together to enable us to speak, think, walk and perform the myriad other things we accomplish every day. You can think of these capabilities as "applications" of the human body that enable us to live our daily lives, without very much attention to "how" our bodies accomplish these amazing things, day in, day out.

Like the human body, our homes are made up of a variety of sub-systems, including the electric supply, plumbing, HVAC, telephones, lighting, computers and security. Each of these sub-systems is made up of individual components and input/output sensors in the home include thermostats, motion detectors, open/closed door and window sensors, humidity sensors, rain gauges, electric utility meters, etc.



Until the past few years, there has been no consistent "central nervous system" for the home, and consumers have had to live with a myriad of network protocols: our home's electrical wiring; copper wiring for POTS (plain old telephone system), Ethernet or Wi-Fi for data communication, infrared for remote controls and a variety of proprietary approaches. The rapid expansion of the Web over the past ten years has shown that most enterprises have more to gain than lose by complying with industry-wide networking standards.

Fortunately, for homeowners, the standards of the Connected Home are becoming more and more clear, and bridge technology is now in place to fill any remaining gaps. As such, utilities can now take their rightful place inside the Connected Home to add value to both consumers and their own stakeholders.

About the Author

Mike Harris is Chief Executive Officer of Zonoff, Inc. As a successful serial entrepreneur, he has founded and/or led numerous venture-backed technology companies to successful exits, including a NASDAQ IPO. Harris is a graduate of Purdue University with a degree in Computer and Electrical Engineering.

EnVision 2030

Ideas for a Better Planet

An Interview with Dr. Russell Lefevre, IEEE Fellow
With Jon Brock, EnVision 2030 Contributing Editor

Part 1 of 3

This is the first installment of our 3-part interview with Dr. Russell Lefevre, a widely recognized IEEE Smart Grid technical expert and chair of the IEEE Steering Committee on Electric Vehicles. Dr. Lefevre is an IEEE Fellow, past president of IEEE-USA, and a member of the American Association for the Advancement of Science and the Aerospace and Electronic Systems Society of IEEE. The interview is conducted by Jon Brock, EnVision 2030 Contributing Editor. This initial session addresses the roles that electric vehicles will play in the future of Smart Grid and the benefits they can provide. Some of the pertinent issues around consumer acceptance of these new and emerging electric vehicle technologies are also discussed. Parts 2 and 3 – appearing in the July-August and November-December 2012 issues – will delve deeper into other facets of V2G development and deployment; be sure to watch for them!

Brock: Let's start with a very basic foundation question: How and why are electric vehicles important to the Smart Grid?

Lefevre: Actually, they are vital to the Smart Grid. There are plenty of reasons why, but one of the key things is that they appeal to major, but dissimilar, communities. Here's what I mean by that: Electric vehicles appeal to environmentalists because most studies show there is a "plus" with respect to the EV carbon footprint. The Pacific Northwest National Laboratory has examined nine scenarios examining the impact EVs will have on the environment, and all showed a significant reduction in greenhouse gas (GHG) emissions, even when the required increase in electric power needed to supply energy to these vehicles was generated in large part from coal-fired power plants, which have inherently high GHG emissions.

Another community consists of those in major developed countries such as China, Australia, Western Europe and the United States that are concerned about importing oil that has inherent price fluctuations and comes from what we'll call 'unreliable' countries. To the extent that Electric Vehicles (EV) are deployed, the dependence on oil is reduced.

Brock: What do you feel is the most important message utilities should communicate about the adoption of electric vehicles and their impact on the Smart Grid?

Lefevre: The most important message is based on a couple of quotes I'd like to share with you.

First, the U.S. Department of Energy National Renewable Energy Laboratory (NREL) has taken the position that: "*Large scale deployment of plug-in electrical vehicles will have limited, if any, negative impact on electric power generation requirements.*"

And EPRI said: "*If plug-in electric vehicles displace half of the all vehicles on the road by the year 2050, they would require only an 8 percent increase in electricity generation – and just a 4 percent increase in capacity.*"

What these quotes say is that if you look at the four elements of the grid – generation, transmission, distribution and consumption – it is very hard to find anybody who has any concerns about generation and transmission. There are, however, significant questions about distribution.

Brock: What are those questions about distribution?

Lefevre: The concern is not about the potential impact on a large aggregated scale, but rather at the neighborhood level. If you have two PHEVs in a neighborhood with three houses and these PHEVS are charging at Level 2 – which uses a 240-volt outlet with a current of maybe 20 to 30 amps – and you start a clothes dryer, you put a significant stress on the transformer serving those houses. This issue is called clustering. It is very scenario-dependent, but it is important. PG&E estimates that PHEV charging at Level 2 (240 volts) is comparable to the average peak summer load of a single home.

Brock: Are there any solutions at hand to address this clustering issue?

Lefevre: Many solutions are being developed. The Smart Grid itself can use demand-response techniques to slow charging, turn it off or relieve the stress on the transformer in some other way. Load-management techniques such as time-of-use tariffs can be employed to motivate people to charge EVs at night.

Brock: But nighttime charging creates other problems, does it not?

Lefevre: Yes, widespread charging at night will change demand on the grid. Many transformers are designed to cool at night, so if you put a significant load on those transformers at night the equipment can't cool down, which can shorten its useful life. This is another item utilities are looking at.

Brock: Could these concerns affect customer adoption?

Lefevre: At this point, most consumers are not really concerned about whether the grid can handle it or not, so it would probably not enter into their EV buying decisions. What most consumers are worried about is cost, and the industry is working on that. Consumers get tax breaks and other kinds of incentives to purchase EVs. Consumers are also concerned about conveniences associated with charging and EV range. Surveys reveal that customers don't want utilities telling them when to charge their vehicles. They want to come home at 6 p.m. and plug in, which further underscores the clustering issue.

Consumers are concerned about availability of charging stations in towns and along highways –and that charging takes too long. The length of time is dependent on the battery. For a 16kWh battery such as in the Chevrolet Volt, Level 1 charging – which is designed for home use – takes about ten to twelve hours, Level 2 (for home or public charging) takes two to four hours. Level 3, for very fast charging, will be of vital importance for charging at outside public locations and along highways, yet at this time nobody really knows what the Level 3 will be. There are no standards, although some fast chargers are already being deployed.

Brock: What would you say are the top concerns about widespread adoption of EVs?

Lefevre: Concern number one – and all the rest of them are lower-level concerns – is not about the potential impact at a large aggregated scale, but at the neighborhood level. As discussed earlier, this is where you might have problems. At the "EV Charging Infrastructure USA 2011" Conference, the people who spoke there were all from utilities or commissioners who deal with utilities, and virtually all of them talked about this clustering issue. IEEE has some notably important researchers, and one of them – Saifur Rahman from Virginia Tech – has studied this issue. It can be a really serious problem that practically everybody recognizes and one for which nearly everyone has a different solution.

Brock: Can you perhaps elaborate a little on what some of those solutions might be?

Lefevre: One solution with direct linkage to Smart Grid has the grid sensing when the transformer is on the verge of being distressed and sending signals that will slow the charging, turn it off for awhile, or possibly initiate other measures to relieve the stress on the transformer. This might include curtailing loads as part of the utility's Demand Response scheme.

With the Smart Grid it is possible to also affect household electric elements. At a Society of Automotive Engineers workshop, it was suggested, for example, that perhaps a swimming pool heater or some other non-essential energy load could be turned off while the vehicle is charging. There are also other viable ways to do this that involve time-of-use charging, charging at night, and cycling air conditioning. All those sorts of things can help minimize potential problems at the distribution level.

Brock: Any other concerns?

Lefevre: As I said, the top concern that I've been talking about here is clustering; the rest of the concerns are somewhat lower in importance, but billing and payment is another one keeping people up at night. That is, electronic communications with EV users will introduce some privacy and billing concerns. Utilities will need to identify EV users in order to bill them, because you can't have a user driving around a city's streets, deciding that they need to charge their EV, pulling up to a charging station, taking out their extension cord, and plugging it in. So then, how does the user pay for power in this scenario, and who gets access to that location data?

Brock: That does seem like a potential issue and one that has not yet been talked about very much – at least not in the public forum. What still needs to be done for a viable billing scheme to be worked out?

Lefevre: For any billing solution to work you first have to know who the user is. This is not an insignificant concern. Southern California Edison is working hard on this, and its experts say that between 2012 and 2015, the company will have separate metering for charging systems in residences, which will be different than metering used for the rest of the house. And they will have public charging and a lot of other services by 2015. Between 2015 and 2020, they will introduce "pay-at-the-charging-point" options. They're going to figure out exactly how to charge a person who plugs into a public charging station. Beyond 2020, they envision a whole suite of other services and conveniences that they're going to introduce to bring electric vehicles into the utility environment.

Brock: How do you see the Smart Home model fitting – or not fitting – into this environment?

Lefevre: The Smart Home, which is directly related to the Smart Grid, of course, will also introduce some concerns because the Smart Home will need a local energy management system and the ability to activate time-of-use tariffs to support EVs. Utilities need to determine how to implement these properly. That is, utilities will have to determine how to implement smart charging, which is integrated with the Smart Grid to reduce the charging rate or change the charging time to help alleviate both the real – and the perceived – clustering issue.

Brock: What are some of the other issues out there?

Lefevre: Another concern is integrating EV charging with renewable energy resources. This is a big deal because environmentalists believe that in the long term, EV charging will likely take significant advantage of renewable energy. Utilities are still developing a vision and methods to make these approaches effective and practical.

Brock: Thank you, Dr. Lefevre, for your valuable insights about EVs and their adoption. We look forward to continuing this dialogue in the future on other EV-centric topics such as regulatory issues, energy policy and the myriad technical issues related to EV evolution and deployments.

Lefevre: You are welcome, Jon. The pleasure is mine…

[Jon Brock is president of Desert Sky Group LLC, an advisory firm based in Denver, Colorado, providing independent and unbiased advice and consulting services to the utility and energy industry. Jon also serves as EET&D Magazine's EnVision 2030 contributing editor and is a longstanding member of the Smart Grid RoadShow Conference Program Committee. EnVision 2030 interviews and presentations are focused on the long-term evolution of the Smart Grid and grid-related technologies.]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Smart Grid 2.0:
The Role of GIS

By Charles H. Drinnan, President, eWAM Associates & Senior Market Analyst, InfoNetrix LLC

As the scope of Smart Grid evolves, some are wondering what the role of GIS will be. GIS will define and maintain more accurate, complete network models and be an integral part of new Outage Management (OMS) and Advanced Distribution Management Systems (ADMS). GIS will provide the geographical organizational aspects of Business Intelligence (BI) and Data Analytics (DA) capabilities. Whether it is analysis of networks or display of Key Performance Indicators, the results will come from time-series simulations that much more nearly model real time network performance.

Smart Grid, Phase 2

As 2012 begins, Smart Grid (SG) projects are experiencing a change in intent, focus and funding. Most initial SG projects (i.e., those enabled by American Recovery & Reinvestment Act funding) are focused on Smart Meter (SM) implementation and improved energy utilization promoted by new rate and billing models. As these projects near full implementation, it is time to define and examine second stage SG objectives – commonly referred to as Smart Grid 2.0.

With ARRA urgency, many utilities rushed to deploy SM without understanding short interval meter data applications or contracting for systems designed to manage new network environments and massive data volumes. Many utilities also postponed SG initiatives that were not directly enabled by SM. The next phase of SM – SG 2.0 – will focus on:

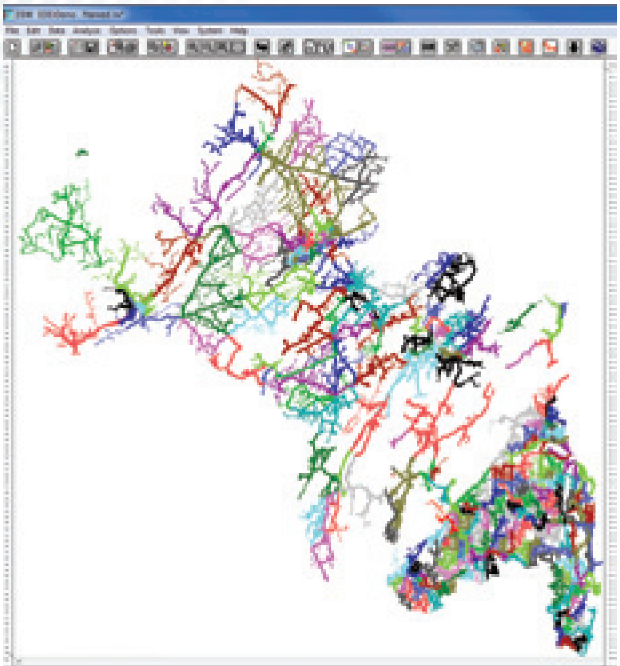
- Completing SM installations
- Implementing Meter Data Management systems
- Supporting Energy Efficiency, Demand Response, Time-of-Use and other real-time pricing and Load Management requirements
- Improving outage identification, verification and restoration
- Implementing new, more accurate network models
- Supporting automated connect and disconnect
- Implementing new BI and DA applications that support massive amounts of SG data
- Improving energy delivery and network reliability with new equipment such as VAR Optimization, synchrophasors, and other monitoring and control devices
- Managing highly variable, distributed renewable generation
- Supporting plug-in electric hybrid and electrical vehicles
- Providing new levels of network control including SCADA, Distribution Energy Management, microgrids and other advanced controls
- Enhanced maintenance to reduce the impact of aging infrastructure and delayed maintenance

Like most SG projects today, the explicit requirements of SG 2.0 will vary from utility to utility.

Evolving from Static Models to Operational Simulations

As SG 2.0 evolves, network modeling will change as summarized below.

1. Static analysis models based on specific configurations and seasonal loads will change to time-based simulation models. Full operational simulations will be available for analysis by dealing with time-series (i.e., what happens as generation sources, loads, and system configurations change over time) analyses.
2. Model accuracy will greatly increase. Rather than static seasonal loads, operational simulations will use hourly loads. For the model, energy sources such as wind and solar will also vary with time to simulate the inherent variability of distributed renewable generation.
3. Models will more closely depict ‘physics’ simulations rather than today’s typical static loads and generalized connectivity models. With a physics model, actual observations are simulated at any point in the network, allowing users to analyze complete network performance with graphs of voltage, loads and other parameters.
4. Today there are many specialized specific purpose models with limited scope and model-specific network properties. With SG 2.0, these specialized models will be replaced by one integrated system model that starts at the source of energy (generation) and flows through a full three-phase model down to individual meters. Virtually every component, including loops, will be analyzed using specific physical component properties.



Utilities will define, monitor and control large, complex models of all components from generation to meter such as this network of 350,000 meters, providing a common model for design, planning, operation and control.
(Diagram Courtesy of Electrical Distribution Design (EDD); Blacksburg, Virginia USA)

GIS and the New Integrated Network Connectivity Models

These new network models are the combination of four enhanced data sources:

1. Topology or connectivity maintained by the GIS
2. Enhanced engineering properties for each network component
3. Enhanced individual customer loads modeled over time
4. Real-time network measurements

Virtually all major GIS systems support complete radial distribution network architecture, but North American utilities don't always capture all of the data supported by the architecture. For example, they may not:

- Capture secondaries, or data may be inaccurate or incomplete
- Use full three-phase models down to the meter
- Connect meters accurately to transformers
- Model looped connections
- Model substations and transmission

Network model status varies from one utility to another. In 2009, a study commissioned by ESRI found that only a third of the surveyed utilities felt their GIS was ready for Smart Grid implementation and that model quality was closely correlated to industry standard work processes. Utilities with good work processes captured new construction in their GIS as part of routine construction and recordkeeping processes.

Utilities with poor work processes were often months behind in posting new construction. In fact, only a third of the utilities interviewed recorded their work within ten days. Utilities that do not place appropriate value on prompt data capture inevitably have inaccurate and/or incomplete data, which can – and often does – lead to other problems.

Utilities will not achieve the promises of SG 2.0 including rapid identification and restoration of outages, improved network reliability, and self-healing microgrid capabilities unless they have accurate three-phase models down to the meter. Although an expensive and time-consuming initial effort often requiring a GIS update, utilities should develop and maintain an accurate network model as part of any SG 2.0 initiative.

Technical Model Characteristics

To simulate model physics accurately, the system must access the physical properties of the network and compute the impedance of each component. Typically GIS do not store the detailed properties with each network component but rather store a key into standard property tables or to another system that maintains the properties.

To validate and calibrate the digital network computations SG projects often add new monitoring devices. The new network models used by OMS and ADMS include these measurements as well as SCADA real time configuration and device readings.

Outage Management in the Smart Grid 2.0 Environment

Newer, more advanced OMS are the major enabling mechanism for improved system reliability. SM, renewable generation, microgrids, and self-healing capabilities impact OMS more than any other system. Modern OMS solutions are integrated with AMI, Distribution Management, GIS, Network Analysis and SCADA so that the OMS can access all network information and control all of the individual network components.

Smart Meters enable outage identification and confirmation as well as standard reliability indices computation. Smart Meters send "last gasp" messages and network restoration messages to the OMS when the electrical service is interrupted or restored. The OMS no longer depends solely on the customer reporting outages and may actually be able to restore power before the customer even reports the outage. SM can also initiate and manage electrical service without requiring crews to physically read meters and initiate/terminate service at the customer premise.

Customers often report false outages resulting in unnecessary and expensive truck rolls. With modern SM capabilities, the OMS can ping the customer to determine the validity of the outage report without traveling to the premise. With the new modeling capability OMS can even predict likely equipment failures before they happen. By repairing the failing facilities, the outage is avoided (or at least minimized), damage to existing facilities is reduced, and system reliability indices are improved.

For microgrids, interconnected circuits, self-healing capabilities and distributed generation, OMS are expected to isolate outages and rapidly return power to unaffected facilities; define self sufficient islands supported by localized generation; and maintain network stability as intermittent renewable energy sources come on line.

Although new OMS deployments will support these new capabilities, many operators are still reluctant to rely on these new tools and replace the manual functions they have trusted in the past. Recognizing operator hesitancy, progressive utilities are implementing new capabilities in phased plans that start with operations support and lead to more aggressive automated reconfiguration.

In addition the GIS will enable the new OMS with the baseline connectivity models; dispatching, scheduling and other spatially-oriented processes; and interactive displays, including planned operations, physical readouts and status maps.

Advanced Distribution Management Systems

To gain SG 2.0 advantages utilities are developing integrated multi-system capabilities. Over the last several years, major hardware and software suppliers have been acquiring and/or partnering with other large system vendors to produce new integrated ADMS solutions. Major component systems include DMS – to monitor and operate the network; OMS, which tracks events and restores interrupted power; and grid optimization capabilities that analyze and 'tune' the grid to use energy efficiently and increase network reliability. These systems integrate with GIS, AMI, MDM, planning, maintenance, and customer systems.

Through mergers, acquisitions and selected partnerships, suppliers with increasingly holistic offerings can provide most of the components of an ADMS in a fully integrated fashion. These suppliers see a market opportunity for a new class of ADMS with tight integration of their existing systems, new SG related capabilities, and upgrades to or replacements of older system components. As a result, utilities can now chose among solutions integrating the latest monitoring and control systems offered by the supplier, "best of breed" systems from other suppliers, or use a combination of new and existing systems.

Intergraph (a subsidiary of Hexagon) is a good example of this approach. Together, Intergraph and Siemens offer fully functional ADMS with tight integration between Intergraph's GIS and OMS and the Siemens DMS and SCADA solutions. However, they also offer their systems integrated with other DMS and SCADA as well as providing stand-alone GIS and OMS solutions.

These ADMS reduce utility integration costs while supporting plug-and-play integration through standards including ICCP, MultiSpeak, and CIM. Many existing systems are specific purpose designs that require a substantial level of alteration and further customization to become effective components of an enterprise-wide ADMS. At a minimum existing GIS database components must be updated to properly support ADMS. Utilities that have not kept up with the latest system releases often decide to upgrade their systems as they implement new ADMS.

Big Data, Business Intelligence & Data Analytics

Over the next five years utilities will make major investments in "big data" opportunities combined with BI and DA. As millions of new smart meters come on line, they will produce massive amounts of data. IT departments must consider whether, how and where to store the data; how to access it; and most importantly, how to translate this massive data repository into actionable information. The 15-minute interval Smart Meter data is combined with SG monitoring data captured at sub second intervals to produce even more data.

Big data represents a new challenge for utility IT departments. However, other organizations – such as telecommunications companies – already manage much larger databases. GOOGLE is a good example of what many people believe to be the largest BI database, providing an excellent illustration of how effectively organized and accessible big data can be translated into an incredibly valuable asset.

New database management systems – examples include OSIsoft's PI Historian, HADOOP, NoSQL, and SAP's in-memory database support – are designed to support less structured, time-series based data. Utilities may chose to store this data in so called 'cloud-based' servers, whether supported by the utility itself or by companies offering managed storage options.

To be useful, stored data must be readily accessible and produce actionable information. In the past, data warehouses have been accessed using BI systems to calculate, measure and compare KPIs. Today, suppliers and utility managers are studying utility business processes and SG data to determine appropriate KPIs for incremental meter readings. Most SM implementations provide meter reading summaries over the Internet to encourage efficient energy usage, creating what is perhaps the first widespread BI application for the SM environment.

Data Analytics (DA) is a modern term closely related to BI, which involves processing a collection of data – for example, time series meter readings or meter readings of similar consumers in a neighborhood – and presenting the results in graphical or spatial contexts. These applications are just being defined and implemented for SG-enabled utilities.

Determining individual load curves is a good example of DA. The user collects a time series for each meter over perhaps a year. The data is then classified by day of the week including special days like holidays and weather (i.e., temperature, cloud cover, etc.) for each meter. The system then derives load curves for each customer for any day and any weather situation through these analyses. These load curves are then used in the real-time OMS and ADMS to simulate expected loads.

Another example analyzes effects of large solar generation on the total network as weather and loads change. For example, using sub-second time intervals and statistical approaches for detailed sun variability and a very fast network simulation capability using load profiles, the total network can be simulated over time and load and voltage profiles can be predicted for any selected point in the network. Using the simulation switching strategies can be determined and the effects analyzed.

Data Analytics and GIS

Many of these new DA results are organized and presented spatially. For example, loads can be categorized, color-coded and displayed geographically by simply having the GIS organize the data spatially and then provide the appropriate display backdrops.

However, the challenge for DA and GIS is when computations require geographical context not only for display, but also for computation. For example, some utilities are beginning to simulate storms to develop plans that reduce the impact and duration of outages. With the projected storm track and Monte Carlo simulation of outages, a statistical model of geographically dispersed outages can be determined. Crews can be located near the storm track to improve outage response and restoration times. Standard outage indices are estimated to compare different storm strategies.

Other Smart Grid Objectives and GIS

SG applications focused on increasing system reliability should consider modern asset management and facility maintenance processes and systems. As our infrastructure continues to decline and maintenance processes are continually postponed, the most effective way to improve system reliability is to maintain and/or replace facilities that will eventually fail. Major causes of outages include aging equipment failures and poor vegetation management. GIS provides the spatial dimensions of preventive maintenance and vegetation management.

For large facilities such as substations, there should be a greater emphasis an Asset Lifecycle Information Management. Full-scale, three-dimensional models should be implemented and maintained throughout the extended life cycle of the facilities.

Summary and Conclusion

GIS applications are necessary enabling components for the achievement of most SG 2.0 objectives. Through modern work processes and more detailed "physics" models, utilities will be able to create and maintain accurate network models for enhanced OMS and ADMS systems. DA and BI applications will present their results in geographically organized displays, and advanced analytics will involve data that is geospatially processed, making GIS integral to the most effective Smart Grid 2.0. solutions.

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THE BIGGER PICTURE

BY BERNADETTE CORPUZ,
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Dancing the Smart Grid Dance in Ontario, Canada: A Case Study Unfolding

This article reviews such deliberations as they are currently unfolding in Ontario where the ubiquitous *Green Energy and Green Economy Act* ("Green Energy Act") of 2009 mandated Smart Grid investments by distributors and transmitters. The Ontario Energy Board ("Board") is now undertaking, within the context of developing a renewed regulatory framework, consultation on the issues that ought to be considered by the Board in the fulfillment of its duty to provide guidance on the establishment, implementation and promotion of a Smart Grid in Ontario.

Smart Grid has moved from being a novel concept to a household word, even though it has yet to be fully developed and implemented. Throughout North America and Europe, the debate has evolved from "do we need a Smart Grid" to "how do we do it". This is unlike most other commercial endeavours. It requires cooperation, openness and the proverbial thinking outside the box. And since the entities that will house a Smart Grid – namely distributors and transmitters – are regulated, any expenditure on developing a smart grid will also typically require a regulator's blessing. How does a regulator give this blessing?

It is not an easy question, even in a jurisdiction such as Ontario where Smart Grid investment, under certain circumstances, is a deemed license condition for distributors and transmitters. Does a jurisdiction need to have the regulatory framework figured out before there is any hope of the realization of a Smart Grid? Or, will it simply be built one way or another with regulation attempting to stay one step ahead to do its job of protecting the ratepayer.

In many jurisdictions, "Smart Grid" still means "smart meters". In Ontario, the smart meter journey began in 2004, five years prior to the introduction of the *Green Energy Act*, with the Province's Smart Meter Initiative. This prelude to the Smart Grid dance began with the establishment of targets by the Government of Ontario, ultimately for the installation of smart meters for all Ontario customers. The Board developed an implementation plan that included mandatory technical requirements for smart meters and identified regulatory mechanisms for the recovery of costs. The Province now has regular smart meter proceedings in which distributors seek rate approval for recovery of smart meter costs.

Thus, the smart meter dance began with Government directing *which* dance (the policy). The regulator then set the music with the consultation document, danced to and fro with stakeholders, and arrived at the implementing regulatory framework.

Will the same dance sequence for smart meters work with Smart Grid? We start the same way – with the Government directing the dance in the *Green Energy Act*. The Act clearly instructs the regulator to dance the Smart Grid dance by adding the following express objective to the Board's governing legislation: "the facilitation of the implementation of a smart grid in Ontario". So far so good but the smart meter is but one component of a smart grid, regardless of what definition of "Smart Grid" one adopts. The *Green Energy Act* thrust the following definition of "Smart Grid" into the province's *Electricity Act, 1998:*

"…the advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of,

(a) enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;
(b) expanding opportunities to provide demand response, price information and load control to electricity customers;
(c) accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or
(d) supporting other objectives that may be prescribed by regulation."

From the outset, the Smart Grid dance is clearly a more complicated one than the prelude of smart meters. The Smart Grid dance will involve many more dancers, require significantly more choreography, but will still need to permit coordinated free-dancing, as contradictory as that may sound.

In Ontario, who really needs to lead the dance? The actual building of a smart grid in Ontario has arguably been vested in transmitters and distributors under the *Green Energy Act* which requires the following:

- Every distributor and transmitter will be required to submit to the Board plans for the development and implementation of the Smart Grid in their system; and

- Each distributor and transmitter will be required, as a condition of license, "to make investments for the development and implementation of the smart grid in relation to the licensees' transmission or distribution systems".

But the plans are only required when the Board mandates them or, if required by regulation. Theoretically, the Smart Grid dance in Ontario could go on hold right here.

Enter the choreographer. *The Green Energy Act* authorized the Minister of Energy to issue directives respecting the smart grid that would be required to be considered by the Board when reviewing plans of licensees. On November 23, 2010, the Minister issued such a directive (the "Directive") to the Board to provide guidance to distributors that propose to undertake Smart Grid activities.

Smart Grid Policy Objectives

The Board's exercise is to be guided by three major categories of objectives that were set out in the Directive – customer control, power system flexibility and adaptive infrastructure.

The Board began the dance immediately with industry by striking a working group composed of technical experts from various stakeholder groups. This working group considered the objectives articulated above and informed the next stage of the Board's considerations. On November 8, 2011, the Board expanded the reach of its dance card by issuing a Staff Discussion Paper in Regard to the Establishment, Implementation and Promotion of a Smart Grid in Ontario ("Board Paper").

Presumably, the Directive's objectives underlie the value proposition of the Smart Grid. But how does this become translated into a value proposition communicated to the customer and perhaps more importantly, accepted by the customer? The interplay of this objective with that of Smart Grid development is not lost in the Board's consultation document.

Key Issues

The Board has asked for stakeholder comment on a number of key issues, two of which are particularly important as their resolution could set the philosophy and footprint for the remaining issues and ultimately, the shape of the regulator's guidance.

Key Issue No. 1 – How should Smart Grid investment be treated?

The Board Paper articulates two potential approaches – (i) Smart Grid as the evolving modernization of the grid, or (ii) Smart Grid investments as discrete and different from "normal" utility practice. The key difference is that the latter approach would involve establishing a list of eligible and non-eligible technologies or activities which would then have rate-setting implications. The Board Paper indicates that this would envisage distinguishing Smart Grid elements from non-Smart Grid or normal elements on the basis of technological categories.

The first approach resonated with the working group struck by the Board as it inherently recognizes that the Smart Grid is the grid of the future. This approach would be the most straightforward to cost recovery and involve a single process for rate applications. The Board Paper emphasizes that serving load and contributing to Smart Grid objectives would have to be complementary and not mutually exclusive. The addition of Smart Grid objectives to traditional tests of reasonable expenditures would be needed to help ensure that the benefits of Smart Grid are not overlooked.

Key Issue No. 2 – In developing principles for the evaluation criteria for the regulated entities, what benefits should the Board recognize?

Regardless of the approach taken to the first key issue, the Board may consider the benefits that should be recognized in its regulatory guidance. Some of these benefits potentially include, as provided in the Minister's policy guidance, (a) increased efficiency of power delivery, (b) reduced operations and maintenance costs, (c) improved system reliability, (d) integration of renewable energy and distributed resources including conservation and demand management, and (e) enhanced consumer services.

The Board Paper recognizes that not all benefit might accrue only to distributors or its customers. Analysis regarding to whom the benefits accrue would be necessary. The Board Paper further emphasizes that consideration of the benefits should not detract from the Board's longstanding focus on customer value and reasonable costs.

The first two key issues perhaps encapsulate the most challenging issues to resolve in the regulation of Smart Grid development. The regulator must continue to protect the consumer and ensure reasonable, prudent activity by the entities that it regulates, yet implement what may be characterized as social and economic policy objectives.

Dance… or Opus?

The Smart Grid dance does not end with the Board Paper. A stakeholder conference is planned for February of 2012 following which the Board will determine next steps. It seems the Smart Grid dance is significantly more complex than a "two-step". But it also seems that a significant part of the dancing population is interested in coordinating steps. While this regulatory exercise is "led" by the Board, stakeholders are intricately involved in every step. In future articles, the author will report on the continuing dance in Ontario and how it compares to those in other jurisdictions.

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With William T. (Tim) Shaw
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SECURITY SESSIONS

Serial Links Are Intrinsically Secure – Right?

Welcome to the latest installment of Security Sessions, a regular feature focused on security-related issues, policies and procedures. As has been expected, at least by every cyber security professional I know, another clever piece of malware made it on the scene recently. A variation on the Stuxnet malware (which is already so 'last year'), this new invader has been given the name Duqu. Unlike Stuxnet, this new infection is primarily an information gathering mechanism, at least to the extent that it has been determined by the researchers doing the dissection. So far, the number of confirmed Duqu infections is limited, but by limited, I mean that it has only spread to eight countries. Thanks to the Internet, cyber plagues can spread around the world in very little time in much the way that jet travel can spread physical plagues. To me, that says the need for good cyber security has never been more obvious.. – ***Tim***.

In previous columns, we've discussed various security technologies and strategies for protecting industrial automation systems against cyber attack. I recently had an interesting discussion with a plant manager that has an in-plant data acquisition system (DAS) that collects information from a wide range of plant subsystems and equipment, and which in turn, feeds this information into both a plant and corporate data historian. The discussion had to do with the presumption that cyber attacks can't occur over serial links. In fact, the person made the statement that serial links are "intrinsically secure".

Allow me to clarify what the person meant by that statement, because point in fact, pretty much ALL communications schemes being used today are "serial". Ethernet is serial – both wired and wireless versions – as are the FieldBus and Profibus standards. Likewise, ATM and SONET are serial. What the person was actually referring to was the use of point-to-point, asynchronous low-speed communications over EIA/TIA-232 or EIA/TIA-422 circuits using basic-capability industrial protocols such as Modbus or DNP3.0. We can even extend that clarification to include multi-dropped communications channels using EIA/TIA-485. The person I was discussing this with probably would have even extended his definition to include things like vendor-proprietary synchronous, moderate-speed local area networks used by PLCs such as Modbus+ and DataHighway+ too. We never actually discussed the point to the level of considering non-Ethernet industrial communications bus standards, such as Fieldbus H1 and Profibus, but I'm reasonably certain that he would have included them in his broad definition of "intrinsically secure serial links" as well.

Essentially, this gentleman was telling me that if it isn't running over Ethernet, using TCP/IP networking, it is "intrinsically secure", and as such, nothing needs to be done about cyber security. Well, I know that if I could make a connection to one of those 'intrinsically secure' communication channels, I could potentially cause a range of problems; anything from causing false and misleading data to be displayed to an operator to commanding a piece of plant equipment to operate in an unsafe or otherwise undesirable manner.

That statement is based on many years of installing and commissioning automation system expansions and upgrades and fond memories of the excitement generated when defective software, improper configuration settings, or just plain human stupidity caused strange and mysterious things to happen. I shudder to think of what we might have done had we been intentionally trying to cause damage.

Okay, I know that the basic assumption for attacking computer systems is to get access to a communications circuit that will route me through intervening devices to the target system. But the fact is, one only needs to get into a device that has connectivity to that communications circuit, which is where the discussion started with my plant manager friend. His in-plant data acquisition system has numerous 'serial' Modbus links that are used to retrieve data from a whole host of subsystems and devices.

That DAS is, in turn, was connected to the plant and corporate Ethernet LANs and has little in the way of cyber protections because, as the discussion indicates, they feel that an attacker can't go any further than the DAS and that DAS data is not 'sensitive'. Moreover, the system would shortly be updated with fresh values from the plant devices and subsystems if corrupted. Essentially, he was saying that if an experienced hacker were able to break into the system's serial communication channels, allowing them to send specifically crafted malicious message traffic to the DAS, it could not cause any serious harm to the plant and could not reach through the DAS to attack other systems.

That presumption actually raises an interesting question, because I've personally seen several instances of cyber security assessments that don't consider 'serial' links as an attack pathway. I'm not talking about a dial-up phone line that is used for remote system access, or even a serial connection running PPP or SLIP as the data link layer for a TCP/IP connection, which are obvious attack pathways. An example of what I am talking about, however, is two critical systems that exchange data via a dedicated serial connection. Is it possible to attack one system from the other and plant malware via a 'serial' Modbus link? Let's think about that possibility.

Having run a couple of computer automation companies that provided DCS, PLC and SCADA systems, I know that we frequently had to develop customized serial drivers to communicate with other systems and smart devices. We had developed several dozen Modbus drivers – and half that many DNP3.0 drivers – by the time I decided that being a shepherd might actually be a superior career choice. As with any other sort of communications software – a Modbus driver for example – expects all messages and responses to conform to the protocol specifications, but we didn't always think about every possible way that messages could be accidentally or intentionally malformed.

Consider this: When a Modbus 'master' asks for 10 register values, if the programmer wasn't on his/her toes, the logic might not check that only 10 values actually come back. Thus, if 10,000 values are returned rather than the expected 10, obviously they have to be stored somewhere. This is the classic "buffer overflow" attack used by hackers over TCP/IP networks; such attacks work in precisely this same manner. Trust me, in debugging Modbus (as well as other serial drivers), we saw many instances where the computer with which we were communicating got hung or crashed because we had a bug in our driver code and generated malformed commands or responses. We were not trying to cause a buffer overflow, but that's what happened.

Of course, that doesn't mean that every Modbus driver has those kinds of bugs. Like any software ever created, the robustness of a given program – particularly one that processes data inputs – is going to depend on how many checking and validation steps were put in the code and at what critical points in the logic. In theory, if I could get a copy of your driver code, I could probably reverse-engineer a buffer overflow attack that would overwrite the Modbus driver code and infect it (i.e., replace it) with my own code – just as it's done via TCP/IP networks in remote exploit attacks. At that point, I would have planted malware in that other system – malware that is running with the same access rights as the Modbus driver it infected! If that other system had TCP/IP and Ethernet connectivity, the malware could then use them to spread to other systems using the same techniques used by "worms".

I've used Modbus here as an example, but I could make the same points about any number of industrial serial protocols. Would an attacker be willing to go to those lengths? (Hint: Consider all we know about the Stuxnet Worm before you answer that question!) Admittedly, this notion is a bit theoretical – not the part about crashing systems with Modbus messages – I know first hand that that can definitely happen. I mean the part about passing malware in this manner. So, if someone is looking for a good doctoral thesis or research topic, I would be interested in discussing these concepts further and seeing the results!

Getting back to the discussion with the plant manager, it also reminded me about how people generally view cyber security. For far too many people involved in industrial automation, the discussion of security usually devolves into a discussion about reliability and the consequences of failure. This is because those factors have been the holy grail of automation engineers for many years. Historically, we designed systems to have full, automatic redundancy, or at the very least, be able to fail gracefully and non-disruptively. The problem here is that cyber attacks – as should be evident by the actions of the Stuxnet Worm – go well beyond the simple desire to shut a system down. In fact, that's probably the least desirable option for a cyber attacker.

In the cyber security realm, we discuss assets being 'compromised' by a cyber attack. Isn't that a great catchall term? It can mean anything from: 'I caused your system to crash' to: 'I have full control over your system and all information it displays is suspect.' If I craft an attack that merely causes your automation system to crash, knowing that for critical processes there is usually some level of backup safety scheme that prevents a catastrophe, I will have gained very little while you will have learned that you have cyber vulnerabilities that need to be eliminated.

But, if I craft an attack that causes your automation system to make periodic, random changes (i.e., start/stop equipment, change loop set-points, change tuning constants or other operational settings), I can disrupt your operations, probably cause you economic harm, possibly cause injury or even loss of life. Yet my attack might go undetected – probably for an extended period – since a long list of other possibilities would be probably suspected long before reaching the conclusion that it must be a cyber attack. Sure, such an attack would require some pretty serious knowledge about your automation system, but what I just said is a good overall description of what Stuxnet was designed to accomplish – so we know it's all possible. Now, we are starting to see the next evolutionary offspring of Stuxnet – Duqu being the first.

Don't be fooled, however; Duqu and even Stuxnet are not magic, no matter how clever their designs might be. They break into systems and spread by simply taking advantage of a combination of well known – and some zero-day – vulnerabilities. Are there are technologies and techniques that would stop them in their tracks – or at least render them ineffective? Yes, but that will have to be the subject matter for a future column... ***Tim***.

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Dr. Shaw is a Certified Information Systems Security Professional (CISSP), a Certified Ethical Hacker (CIEH), a Certified Penetration Tester (CPT) and has been active in industrial automation for more than 35 years. He is the author of Computer Control of BATCH Processes and CYBERSECURITY for SCADA Systems. Shaw is a prolific writer of papers and articles on a wide range of technical topics, has also contributed to several other books and teaches several courses for the ISA. He is currently Principal & Senior Consultant for Cyber SECurity Consulting, a consultancy practice focused on industrial automation security and technologies. Inquiries, comments or questions regarding the contents of this column and/or other security-related topics can be emailed to tim@electricenergyonline.com.

Power to the Customer!

By Peter Kelly-Detwiler, Senior VP, Demand Response
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Transparency is the watchword today, and the utility sector is no stranger to the changing ways of today's increasingly wired world – in a good way. Until recently, managing power consumption has been a guessing game of sorts for many commercial and industrial businesses, with electricity bills arriving as many as five weeks after the first kilowatt-hour is consumed. This lag time leaves little, if any, room to manage energy use and costs, and even less opportunity for achieving increasingly important sustainability goals. With the growing desire for spot market intelligence and the popularity of load response programs, in which facilities curtail power usage for financial incentives, the dynamics for overall energy management drives the need for centralized monitoring and control.

Fortunately, technology is beginning to revolutionize the capabilities of energy managers through the advent of energy dashboards. Many online dashboards can now provide a real-time view of energy consumption, enabling facility managers to more closely monitor – and subsequently manage – power usage and related expenditures. Some provide real-time pricing information, as well.

The best dashboards, however, offer not only the ability to see the usage and pricing dynamics, but also the capability to participate in the electricity markets. With these developments, load response is also becoming a standard component of overall energy strategies in many markets, and online energy management has paved the way for businesses to handle energy usage and costs like never before.

The Rise of Automation

Energy management is adapting quickly to the rise of web-based monitoring of both usage and market prices and the resulting ability to better manage total costs. In order to optimize this newfound capability, the next natural step is to add automation to the process. This is particularly important in buildings, where there are often numerous controls systems and many energy-consuming assets whose behaviors can be modified.

Typically, energy management strategies need to map against a variety of building automation and controls systems and both adhere and adapt to specific facility requirements. Web-based online energy management platforms, such as those offered by Constellation Energy and others, provide the ability to automate and select from various pre-engineered strategies.

For example, hotel ballrooms would be potential zones for load curtailment, unless a facility is hosting a wedding in a particular ballroom, during which time that specific zone could be placed off-limits for adjustments. This type of setting can be automated as facility managers are able to choose which assets to deploy or avoid – all done online and in real-time, but with the capability for manual override where necessary.

Vornado/Charles E. Smith, based in the Washington D.C. region, recently saw the benefits of online monitoring and automation firsthand. During an extreme summer heat wave, Vornado received a signal from the grid to participate in a load response event to help avoid a potential blackout. The facility managers were able to select the appropriate pre-determined strategies with a few clicks of a mouse and create an automated response in 27 buildings under management without affecting tenant comfort.

The latter accomplishment is extremely important; that is, as load response grows into a more critical ingredient of overall grid stability, it is likely to be called upon more frequently. It is therefore important to deploy strategies that are non-intrusive and that can be frequently called upon to avoid or minimize disruption to a facility's daily activities.

Beyond helping to avoid a potential grid emergency, online energy management and its automated capabilities help to promote sustainability efforts and foster overall energy efficiency and awareness. Load response – as managed by these online tools – ultimately enables a facilities manager to reduce energy costs without affecting the critical mission of providing a safe, comfortable and secure environment to the tenant.

Raising the Bar

With volatile electricity pricing, an aging infrastructure, and growing stress on the grid, it's easy to understand why constant monitoring and automation are beneficial for assessing and managing power usage at an efficient level. However, getting a taste for the possibilities of virtual online management presents both advantages and new challenges for facility managers, and online energy management providers are working to anticipate and meet those needs, such as:

- Enabling mobile access to and control of energy use through device apps;
- Allowing an enterprise-wide view of energy consumption;
- Showing weather condition and power consumption correlations;
- Providing custom dashboard views and user-defined roles; and
- Sending automated notifications for price, usage, and load response compliance.

Conclusion

As long as power consumption continues to outpace capacity, and investments in grid infrastructure do not keep up, we are all at the mercy of the grid. However, as energy managers learn more about the capabilities available to them in monitoring and managing power use and load curtailment, their strategies will evolve and become more fruitful. Increasingly sophisticated online energy management and automation systems are able to arm businesses with greater visibility into – and control over – power use. Increasingly, the "power" is in the hands of the customer.

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