PP40010982

Electric Energy T&D MAGAZINE

MAY-JUNE 2013 Issue 3 • Volume 17

Going Underground to Feed Downtown

Anthony Haines, President and CEO of Toronto Hydro Corporation

Electric Energy T&D MAGAZINE

Publisher:
Steven Desrochers:
steven@electricenergyonline.com

Editor in Chief:
Terry Wildman:
terry@electricenergyonline.com

Contributing Editors:
- Anthony Haines, President and CEO of Toronto Hydro Corporation
- Eric Byres, P. Eng. and ISA Fellow
- By Bernadette Corpuz, Borden Ladner Gervais LLP

Account Executives:
Eva Nemeth: eva@electricenergyonline.com
John Baker: john@electricenergyonline.com

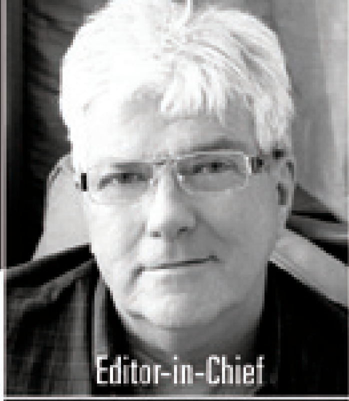
Art Designers:
Anick Langlois: alanglois@jaguar-media.com

Internet Programmers:
Johanne Labonte: jlabonte@jaguar-media.com
Sebastien Knap: sknap@jaguar-media.com
Tarah McCormick: tarah@jaguar-media.com

Electric Energy Magazine is published 6 times a year by: Jaguar Media Inc.
1160 Levis, Suite 100,
Terrebonne, QC Canada J6W 5S6
Tel.: 888.332.3749 • Fax: 888.243.4562
E-mail: jaguar@jaguar-media.com
Web: www.electricenergyonline.com

Electric Energy T&D Magazine Serves the fields of electric utilities, investor owned, rural and other electric cooperatives, municipal electric utilities, independent power producers, electric contractors, wholesalers and distributors of electric utility equipment, manufacturers, major power consuming industries, consulting engineers, state and federal regulatory agencies and commissions, industry associations, communication companies, oil & gas companies, universities and libraries.
Post Publication mail agreement #40010982
Account #1899244

COVER PAGE IMAGE: Credit should be to Grayson Power Plant, part of Glendale Power & Water (GWP)



TERRY WILDMAN

POWERPOINTS

The Upside of Falls

When I was a young lad attending public school in Toronto, one of the favourite day trips laid on every year was a visit to the Sir Adam Beck* generating station (GS) near Niagara Falls, Ontario. On the way, there was always a stop at Niagara-on-the-Lake to visit Fort George, which served as a headquarters for the British Army during the War of 1812. The fort was interesting but, for a bunch of young kids, lunch was far more appealing as evidenced by the way we tore into our brown-bags. When lunch was over we travelled south to Niagara to spend the rest of the day on a tour of the power plant.

The term *'half the fun is getting there'* may have been true on a cruise ship but was certainly lost on several kids as our bus barrelled along the highway in the noon-time heat. In those days opening the side windows of the bus while underway was acceptable and every kid that could took advantage of that and put their arm out to feel the wind. As luck would have it, a kid in the front row got car-sick and started hurling out his open window. He had magnificent aim as a copious amount of a hot, soupy mixture of peanut butter and jam sandwiches, cookies, and milk sprayed the outside length of the bus hitting every exposed arm along the way. At that age, the mere smell, sight or sound of vomiting begets vomiting so you can imagine the rest.

Many people would think the bus episode was the only thing a grade school student would remember about that day. For me, the excitement of the fun-filled bus ride notwithstanding, I will never forget my chin dropping a mile as we entered the power plant. I was overwhelmed by the sheer size of the facility. The floors were so large they seemed to have no end and the ceiling must have been in the clouds. The hum of the giant turbines creating electricity penetrated everything, including us. To this day, I am still gob smacked by industrial behemoths and marvel at their mechanical might. I have returned to the station with my kids since and am still fascinated by its powerful history and proud of its future.

Adam Beck's manufacturing enterprise made him a tycoon and he enjoyed using this 'strength' to further his ambitions both in business and as a Conservative party member. In 1905, the then leader of the government made Beck 'Power Minister' and chairman of the Hydro-Electric Power Commission of Ontario, the world's first publicly-owned utility. Given Ontario's immense water power resources at Niagara, Beck became an early prominent advocate of municipal and provincial electric power ownership making electricity available to Ontario users at cost. He fiercely opposed privately held companies insisting they never gave ratepayers good value. Beck was instrumental in developing the 450 MW Queenston Chippawa power station at Niagara. The facility was later renamed Sir Adam Beck 1 and, at the time, it was the largest power station on the planet.

POWER POINTS

Standing there some 50 years ago I never would have guessed how many millions of people would come to rely on the electricity generated by the two plants named after Beck. Nor would I have thought its generating capacity could be increased. But increased it has.

On March 21 of this year, the new Niagara Tunnel was put into service, a monster that can produce more power annually than is consumed by a city of 150,000. Begun in August, 2005, it is a major clean-energy project by Ontario Power Generation (OPG), the province's publicly-owned power utility. When under construction, the tunnel was the largest renewable energy project of its type anywhere in the world.

The largest hard rock boring machine in existence, nicknamed Big Becky for this job, was used to create the massive new tunnel. It runs from the upper Niagara River parallel to the two existing tunnels that run under the City of Niagara Falls that have been operational since the 1950s. At a maximum depth of 140 metres (459 feet) the new tunnel sits 40 metres (130 feet) lower than the other two. The force of gravity alone propels the water through the 10.2 kilometre (6.3 mile) long structure. At 12.7 metres (41 feet) wide – enough to fit a double-stacked container freight train – 500 cubic metres (17,660 cubic feet) of water per second rush through the tunnel towards the waiting blades. Some have done comparisons equating that much water to filling Olympic size pools but it's lost on me in the same way filling football fields get lost. I just know it's one heckuva lot of water rushing beneath your feet. According to Bob Chiarelli, Ontario's Minister of Energy, this new tunnel will provide the province with a source of clean energy for at least the next 100 years.

Ontario is home to more than 250,000 bodies of water that can be considered lakes making water a natural source of power. As I write this, several renewable hydroelectric projects of varying sizes are at different stages throughout the province including:

1. New Post Creek Project – a partnership between OPG and Coral Rapids Power LP (CRP) that proposes the development of 25 MW of power by diverting water from New Post Creek into a new generating station located near Fraserdale some 150 kilometres (93 miles) southwest of James Bay. It is under the watchful eye of the provincial Environmental Assessment Act for waterpower projects. A new seven kilometre (4.4 mile) long transmission line will connect the CRP power to an existing Hydro One line.

2. An OPG proposal to expand the Ranney Falls GS with the addition of a new 10 MW hydroelectric generating unit and powerhouse to replace an expired 0.8 MW unit on the existing site. The existing forebay and tailrace channel will also be improved. This will increase the station's capacity to approximately 18 to 20 MW overall. A new substation will connect with an existing Hydro One Networks Inc. distribution line. The project is located on the Trent Severn Waterway at Campbellford, about 150 Kilometres (93 miles) northeast of Toronto. Environmental approval will be granted this year.

3. Little Jackfish Project, which is located about 240 kilometres (150 miles) northeast of Thunder Bay on Lake Superior. It will see approximately 78 MW of renewable hydroelectric power added through a newly constructed GS on Little Jackfish River that drains into Lake Nipigon. Dam automation, construction of a 180 kilometre (112 mile) long 230 kV transmission line to connect the GS to the grid, and a 25 kV line connecting the GS to the dam comprise the undertaking. When completed, the 380 gigawatt hours of energy can light up 78,000 homes. OPG is in constant contact with all respective First Nations and Métis government agencies and local peoples to ensure any environmental concerns are addressed.

4. Approximately 440 MW of new hydro power that will be produced in northeastern Ontario by the Lower Mattagami River project. The clean energy will come from additional generating units at Little Long, Harmon, and Kipling, and a replacement single three unit station at Smoky Falls. The four stations are all on the Mattagami River approximately 200 kilometres (125 miles) southwest of Moose Factory, a town that sits near the southern tip of James Bay. When operational a total of 924 MW of renewable electric power will be available on demand for the region.

I have to say that I feel incredibly privileged to be part of the fabric of a place that boasts such a vast source of clean energy and awe-inspiring beauty.

* In 1914, Beck was knighted by King George V for services rendered to the Commonwealth of Canada.

Laminated Wood Systems, Inc. Introduces Patent-Pending Glu-lam Manufacturing Design

SEWARD, NE – LWS has developed a new, patent-pending, glu-lam manufacturing process called PentaTrate™. The PentaTrate™ design features a grooved, un-glued edge joint on multiple-layup E-LAM® laminated wood poles. The PentaTrate™ groove runs the entire length of the pole on the inner edge joints, allowing for full-length penetration of preservative during the pressure treating process. Once the poles are installed, the PentaTrate™ grooves also facilitate drainage of any moisture that may enter the pole. Forensic tests have been conducted that confirm the successful migration of preservative treatment around the PentaTrate™ grooves the entire length of the pole. This improved glu-lam manufacturing design is expected to significantly increase the already long life of E-LAM® laminated wood poles for many additional years. For more information in this new, revolutionary design improvement that is unique to E-LAM® poles, call 800-949-3526 or visit www.lwsinc.com today.

ComEd's "Smart Switches" Reducing Service Interruptions
"Self-healing" technology key to improving reliability

Chicago, IL, April 2013 - ComEd submitted this month (April) to the Illinois Commerce Commission (ICC) a progress report showing major accomplishments in the first year of the smart grid program, including the installation of 470 Distribution Automation devices. Distribution Automation routes power around potential problem areas, often with no noticeable interruption in service. Installation of these devices resulted in 82,000 fewer customer power interruptions in 2012. During the severe storms that hit the Chicago area in mid-April, DA devices prevented 20,000 service interruptions.

By remotely monitoring and controlling grid operations, Distribution Automation (DA) devices, or smart switches, are a central feature of smart grid technology and ComEd's effort to reduce the frequency and duration of outages.

Working at an accelerated pace in 2012 as a result of the smart grid law enacted in 2011, ComEd installed more than 470 DA devices. Over the course of the 10-year grid modernization program, ComEd is increasing the number of customers served by DA from 55 to nearly 90 percent. The utility invested a total of $32 million in the installation of DA in 2012 and is increasing the investment to over $44 million this year.

"Just as today's smart phone technology merged the power of computers with cellular phones, smart grid technology merges the power of computers with the electric grid," said Mike McMahan, vice president of smart grid and technology, ComEd.

"With distribution automation, if a tree were to fall on a utility pole resulting in an interruption, far fewer customers would be impacted because it enables us to better isolate the damaged section," explained McMahan. "DA introduces a self-healing capability to the electric grid by allowing us to resolve issues before customers might even be aware of them, and that has a profoundly positive impact on people's daily lives."

When fully implemented, distribution automation and smart meters will communicate with ComEd's operations center, alerting the utility of an outage and eliminating the need for customers to call to report they are out of power. Smart meters will enable the utility to know as soon as power has been restored. When DA is on a system serving homes with smart meters, the utility can more efficiently dispatch personnel to the appropriate locations to accelerate restoration. To see how smart meters and DA devices work together, click this link http://youtu.be/L4xp7a1di7Y.

Under the smart grid law, ComEd committed to spend $2.6 billion over 10 years to strengthen and modernize the electric grid in northern Illinois. More than $1.3 billion is earmarked to deploy a Smart Grid system and install smart meters in four million homes and businesses to give customers greater control over their energy consumption and costs. The current schedule calls for ComEd to begin installing smart meters in 2015. However, the General Assembly passed legislation last month that would accelerate installation to begin later this year if Gov. Pat Quinn enacts the measure during the spring legislative session.

The progress report filed with the ICC summarizes ComEd's activities and achievements in 2012 and goals for 2013 in several areas, including smart meter deployment, customer applications, customer outreach and education, metrics and milestones.

One in Five Consumers Believe Smart Meters Will Create UK Class Divide
Consumers believe smart meters will capture too much personal information and will be vulnerable to cyber attack

London, UK, April 2013 - Tripwire, Inc., a global provider of IT security solutions, announced the results of a survey of 1,000 U.K. consumers on smart meter privacy. The research revealed that British consumers believe utility companies will only install smart meters in high-earning households, creating a class division, despite widely publicized benefits that include reduced energy bills and improved environmental consciousness.

Key research findings include:

- Almost 10% of respondents think that smart meters will be targeted by cyber criminals
- Over 10% of respondents believe smart meter consumer data will include Personally Identifiable Information (PII), such as bank details, date of birth and addresses
- Almost 80% of respondents believe smart meter PII will require additional security
- 73% of respondents believe consumers should own smart meter consumer data

INDUSTRY NEWS INDUSTRY NEWS INDUSTRY NEWS

Commenting on the research, Dwayne Melancon, chief technology officer for Tripwire noted, "Consumer fears about smart meter privacy are well founded. In a recent survey, energy industry security professionals identified metering infrastructure as one of the highest risk areas in smart grids. Smart grids - the energy infrastructure connected to smart meters - comprise of an enormous range of technology, each of which introduces many potential vulnerabilities that may be susceptible to cyber attack, and we are adding new technologies all the time. This ever-increasing rate of network complexity, combined with the lure of easily monetized consumer data, will inevitably draw the attention of a wide variety of cyber attackers."

Melancon continued, "Without adequate security controls, our critical infrastructure will continue to be at risk, and this is uncharted territory for many utilities providers. Fortunately, there is readily available guidance on critical security controls that can quickly mitigate or reduce these risks."

Smart meters are electrical meters that record consumption of electric energy in intervals of an hour or less. They communicate information back to the utility for monitoring and billing purposes at regular intervals. They were launched in the UK in 2009 in a bid to help consumers save money on energy and be environmentally friendly.

Horizon Utilities first company to achieve Sustainable Electricity designation

Hamilton and St. Catharines, ON, April, 2013 - Horizon Utilities Corporation is the first company in Canada to earn the Sustainable Electricity CompanyTM designation from the Canadian Electricity Association (CEA).

"We're very honoured to be recognized by the CEA for our commitment to advancing sustainable business practices in our operations," said Max Cananzi, President and CEO of Horizon Utilities Corporation. "This is an exciting day for Horizon Utilities and the electricity sector. This is also validation of a strategy we introduced several years ago as part of our commitment to contributing to the sustainability of our communities."

The Sustainable Electricity CompanyTM designation was established by CEA for utilities across Canada and worldwide. The designation requires utilities to commit to ISO 14001 standards on Environmental Management Systems and ISO 26000 guidelines on Social Responsibility. In addition, companies must also pass a third-party external verification to validate the implementation of CEA brand criteria.

"I am impressed with the level of commitment the sector has dedicated to sustainability over the last few years, and I particularly congratulate Horizon Utilities for the leadership it has shown," said David Morrison, President and CEO of Yukon Energy Corporation and Executive Chair of the CEA Sustainability Committee.

Horizon Utilities is the current recipient the CEA's Sustainability Company of the Year Award, having won in both 2011 and 2012. The company's business practices are governed by its Sustainability Policy and it evaluates its sustainability performance using the Global Reporting InitiativeTM (GRI) framework. The organization also publishes a 'sustainability-based' annual report, documenting the social, environmental and economic dimensions of its business in equal measure. Horizon Utilities adopted its sustainability strategy in 2008.

"This is a historic day for the Canadian electricity sector," said Jim Burpee, President and CEO of the Canadian Electricity Association. "I congratulate Horizon Utilities for attaining this brand designation based on internationally recognized standards."

ComEd Files Delivery and Transmission Rate Updates for 2014
Low energy costs to offset delivery increases, keeping total bills stable

Chicago, IL, April, 2013 - ComEd filed its annual delivery service rate update with the Illinois Commerce Commission (ICC) to reflect grid modernization and other service-enhancing investments, as required by law. This filing marks the third formula rate filing under the 2011 Smart Grid law, and the new rates will take effect January 2014, after approval by the ICC.

Under the filing, ComEd's delivery service charges would increase by about $5 on the average monthly residential bill starting in January 2014. This increase, however, will have already been offset by a 17 percent drop in total average bills that starts this June for customers on ComEd supply. This means that even with the proposed January increase, customers on ComEd supply will still be paying about 10 percent less on their electric bill in 2014 than they are today. Customers that have switched to alternative suppliers for their electricity supply have been realizing lower costs already.

"The investments we're making today will create long-term benefits and savings for our customers," said Anne Pramaggiore, president and CEO, ComEd. "This work is already improving system performance and customer satisfaction and creating jobs in Illinois. Making these long-term investments now, when energy supply costs are low, keeps customers' total bills stable."

ComEd also filed with the Federal Energy Regulatory Commission (FERC) for its annual adjustment in transmission rates, which would mean an increase of about $1 on the average monthly ComEd residential customer bill. This goes toward investments in high-voltage lines to improve system reliability, partly as the result of coal plant retirements and increasing wind power on the system.

While ComEd's smart meter installation is currently set to begin in 2015, it could start in 2013 if Senate Bill 9, which was passed recently by the Illinois Senate and House, is enacted this spring. The measure has been sent to Gov. Quinn for his signature.

ComEd offers payment options and assistance to customers most in need. The utility announced in March that it has dedicated $10 million in CARE customer assistance funds for the second consecutive year, as a result of the Smart Grid law. Last year through the CARE programs, ComEd was able to help more than 32,000 customers with their bills.

INDUSTRY NEWS

FPL marks completion of DOE-supported electric grid enhancements and 4.5 million smart meter installations in Florida

Juno Beach, FL, April 2013 - Florida Power & Light Company has successfully completed its Department of Energy-supported grid modernization projects and the installation of 4.5 million smart meters in its 35-county service area. FPL President Eric Silagy announced the two milestones during a celebratory event at FPL's grid monitoring center in Palm Beach County that was attended by Patricia Hoffman, Assistant Secretary of Energy for the Office of Electricity Delivery and Energy Reliability, local dignitaries and business officials.

"This is one of the most ambitious projects that has ever been undertaken in the country and definitely one of the most ambitious projects that FPL has undertaken," said Silagy. "Completing the installation of the 4.5 million smart meters and the deployment of smart grid technology throughout our service territory is making it possible for us to improve our service reliability, prevent outages and detect problems, while giving customers more control over the energy they use."

"In 2009, we began the deployment of state-of-the-art smart grid technologies as part of our commitment to building a smarter, more reliable and more efficient electrical infrastructure," explained Silagy. "While we celebrate the installation of 4.5 million meters nine months ahead of schedule, at FPL we never stop working to deliver reliable, affordable electricity for our customers."

FPL was one of only six utilities in the U.S. to receive a $200 million grant from the DOE to help fund one of the largest, most comprehensive grid modernization projects. Now, four years later, with an additional $600 million investment from FPL, the installation of these smart grid technologies place FPL among the first utilities to complete its commitment.

"Situational awareness plays an important role in improving the reliability and resiliency of the grid," said Patricia Hoffman, Assistant Secretary for the Office of Electricity Delivery and Energy Reliability at the Department of Energy. "DOE funding of this FPL project and others is helping utilities and system operators across the nation get a faster, more accurate picture of the status of the grid, allowing them to respond more quickly and efficiently when disruptions occur."

FPL's investments in a more efficient electric grid provide customers with tangible benefits while laying the foundation for a host of future benefits and operational efficiencies such as:

- Real-time information on the health and performance of the electric grid
- Ability to identify outages and diagnose their causes, so FPL can get to work restoring power faster
- Verification that power was restored
- Early warning of power issues to enable rerouting electricity around trouble spots, thus confining outages to smaller areas
- Remote communications with FPL through advanced technology
- Greater information for FPL customers about their energy use so they can make smart decisions about conserving electricity

"This technology truly is transforming how we create, transport and deliver electricity," said Silagy. "While we're marking important milestones today, this is just the beginning. We're continuing to find new ways to use this technology to enhance the everyday value we provide our customers for many years to come."


THE WORLD'S FIRST WIRELESS BROADBAND PRODUCTS DESIGNED SPECIFICALLY FOR ELECTRIC POWER
RUGGEDCOM
A Siemens Business
Begin building a future proof network
www.RuggedCom.com/wireless

Coosa Valley Electric Cooperative Chooses Milsoft GIS & Field Engineering

Abilene, TX, April, 2013 - Milsoft Utility Solutions, Inc., Coosa Valley Electric Cooperative (EC) in Talladega, Alabama, has chosen Milsoft Geographic Information System (GIS) and Milsoft Field Engineering (FE).

Coosa Valley EC is collecting and organizing the data necessary to better model and analyze its electrical distribution system and manage its assets so as to be able to plan, engineer and operate as reliably, economically and efficiently as possible. "As the demands on our electric distribution system become not only greater but more complex, we must have an accurate, detailed computer model and facilities data base," said Manager of Engineering Ryan Hart, "Milsoft GIS and FE will enable us to do both."

Milsoft GIS is used by 150 electric utilities for electric utility mapping and asset data management. The powerful yet easy to use software is fully integrated with ESRI GIS tools. It is unique in its capability to create and maintain a detailed electric network circuit model. Milsoft Field Engineering enables rapid, efficient collection and utilization of data from field design of system additions and improvements. Milsoft GIS and Milsoft FE together provide the data capture, management and display capabilities that a utility needs to maximize the many benefits of using GIS.

AEP Receives FERC Approvals To Transfer Ohio Generating Assets Company continues to makes progress in transition to full competition in Ohio

Columbus, OH, May, 2013 - American Electric Power (NYSE: AEP) received approval from the Federal Energy Regulatory Commission (FERC) to separate its Ohio generating assets from its Ohio distribution and transmission operations and transfer these assets to a competitive generation company and regulated affiliates. AEP is awaiting FERC approval of additional transactional agreements between AEP affiliates.

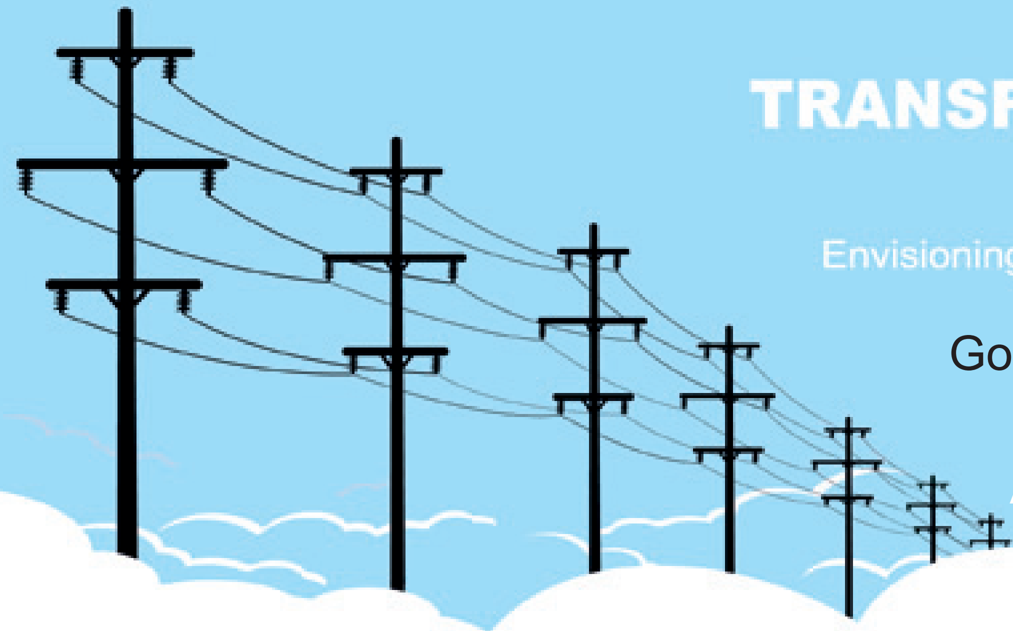
"With these approvals, we reached another milestone in the transition to full electricity competition in Ohio. The FERC decisions allow us to move forward with the ownership transfer of our Ohio generation-related assets into a separate unregulated generation company and to other AEP operating companies," said Nicholas K. Akins, AEP president and chief executive officer. "We anticipate decisions from FERC on our other related filings soon and expect to fully separate our Ohio generation from our Ohio utility operations at the end of this year.

"We will continue to work with regulators in Kentucky, Virginia and West Virginia to seek the additional approvals necessary to transfer ownership of the Mitchell Plant and the AEP Ohio-owned share of the Amos Plant to Appalachian Power and Kentucky Power to help satisfy their existing and long-term generation requirements," Akins said.

The FERC's April 29 decision approved the transfer of AEP Ohio-owned generation to a new wholly owned company – AEP Generation Resources Inc. The FERC also approved further transfer of AEP Ohio's two-thirds ownership (867 MW) in John E. Amos Plant Unit 3 (1,300 MW) and ownership of 800 MW of the 1,600-MW generating capacity of Mitchell Plant to Appalachian Power as well as ownership transfer of the remaining 800 MW of Mitchell Plant to Kentucky Power.

Additionally, the FERC approved merging AEP's Wheeling Power utility into Appalachian Power.

AEP's application to terminate the interconnection agreement, or pool, that exists among AEP's utilities in the Midwest and for approval of a new Power Coordination Agreement among Appalachian Power, Kentucky Power and Indiana Michigan Power remains pending before the FERC, along with other tariff filings related to corporate separation. AEP anticipates implementing corporate separation and the other items in the related filings by Dec. 31, 2013.



Going Underground to Feed Downtown

We are speaking with Anthony Haines, President and CEO of Toronto Hydro Corporation

EET&D: Why does downtown Toronto need a new transformer station?

Haines: In downtown Toronto, our grid is old and our station loads are nearly at capacity. We need a new station to 'back up' our Windsor Transformer Station in order to enable staged replacements of its end-of-life, air-blast switchgear. As well, we currently do not have station redundancy. Right now, Windsor Station supplies much of the financial district, the convention centre and the CBC headquarters, among many other large and important customers. In addition, the city is growing at an unprecedented rate. There are 189 high-rise buildings under construction, which is double the number in New York City (82 buildings) and this means increased demand on the electricity grid.

We currently operate five transformer stations in the downtown core. Four are near capacity. Overloading at Windsor Transformer Station is expected to occur by 2017. Overloads at the Esplanade, Strachan, and Cecil Transformer Stations are expected in 2018, 2022, and 2022 respectively.

This will be the first transformer station built in downtown Toronto since the 1960's. The station will prop up capacity for these stations and provide additional capacity in anticipation of continued development.

EET&D: How will this station serve the future energy needs of downtown Toronto?

Haines: The latest economic report says that Toronto has moved ahead of Chicago and is now the fourth largest metropolitan area, by population, in North America. Between 2006 and 2011, the population in the city's downtown increased by over 50 percent, while the population in the city as a whole increased by just over nine percent. Based on Toronto Hydro's load forecast, between 2017 and 2022 anticipated load increases will exceed the ability of the company's five downtown stations to handle demand.

The new transformer station will address this issue. The station will add a total of 144 MVA of capacity, which is the equivalent to approximately 70 condo buildings.

Located in the heart of downtown Toronto, the station will power major Toronto institutions including the CBC, Rogers Centre, and the new Ripley's Aquarium. It will also connect to new infrastructure along Queens Quay which is being revitalized as part of Waterfront Toronto's vision.

EET&D: What is unique about this project?

Haines: There are a number of unique aspects of this project, but probably the most obvious is that the majority of the station will be built mainly underground. This is just the second underground transformer station in Canada - the first being in Vancouver. Once it's complete, the station will be approximately 50,000 square feet, with three floors spanning 40 feet below grade. We're also using more modern equipment like gas insulated transformers. This is the first installation in Canada using this type of equipment and one of the first in North America.

The station is also located on a designated heritage site, adjacent to Toronto's landmark Roundhouse building. This means that special consideration must be made during construction. For instance, a Machine Shop located on the site, which was historically used for repairing rail cars, must be taken apart brick by brick to build the station and reassembled exactly as it was once the station is complete.

EET&D: Why build the station underground?

Haines: Because of its location in one of the busiest, most highly-populated areas of the city, building the station underground is the only option. Real estate is scarce and we don't have room to build a sprawling above-ground transformer station. Housing everything underground reduces the station's overall footprint and allows it to blend-in aesthetically with the neighbourhood.

APPA Academy
Where Power and Knowledge Meet

DISCOVER THE POWER!

APPA NATIONAL CONFERENCE & PUBLIC POWER EXPO

Gaylord Opryland Resort
& Convention Center
June 14–19, 2013
Nashville, Tennessee

PUBLIC POWER DAY OF GIVING

June 14

PRE-CONFERENCE SEMINARS

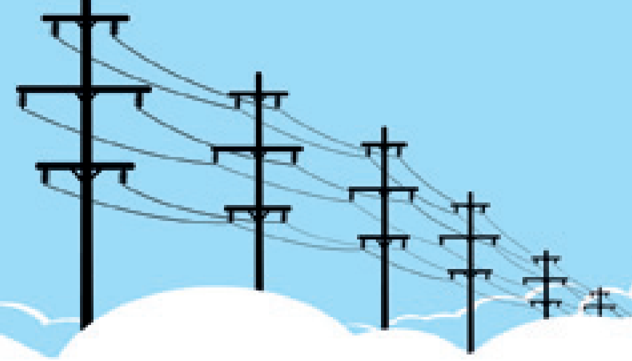
June 15–16

At public power's largest annual gathering, you will:

- Discover the innovative ideas, new technologies, and political, social and economic trends shaping our industry and our nation.
- Learn about new rules and regulations, and how they will impact you.
- Connect with hundreds of public power leaders, including utility boards, mayors, city council members, utility executives, senior managers, and industry partners.

www.publicpower.org/NationalConference

2013
AMERICAN PUBLIC POWER ASSOCIATION
National
CONFERENCE



EET&D: How will construction unfold?

Haines: With our recent approval from the Ontario Energy Board to proceed with the project, our crews have just completed pre-construction work to prepare the site, which included building a temporary roadway, relocating underground services, and cleaning up the Machine Shop. The station will be built under the existing Machine Shop, which will be re-assembled after construction of the station is complete. The Machine Shop will house the protection, control and station service equipment, while the major equipment (transformers, switchgear, cabling, etc) will be housed below. Electrical supply for the station will be taken from existing 115 kV electrical circuits within Hydro One's Front Street tunnel, located 100 feet underground. From the tunnel, cables will be routed via a new underground cable tunnel to the new transformer station, where the 115 kV will be stepped down, through transformers, for distribution to customers. The new station is expected to be complete by the end of 2014.

EET&D: Many thanks Anthony for taking the time to speak with us and explain to our readers the upgrades Toronto Hydro is making to its electricity system to ensure Toronto Hydro continues to meet the ever-growing demands this large city places on electric power flow.

About the Interviewee: **Anthony Haines** is the President and Chief Executive Officer of Toronto Hydro Corporation and its subsidiaries, one of the largest urban electricity distribution companies in Canada. He is a seasoned leader with over 25 years of experience in the Canadian energy industry, including 15 years in various senior roles in the natural gas industry.

Mr. Haines has been a member of the Canadian Electricity Association board since 2006 and is actively involved with the Ontario Coalition of Large Distributors. He is a past board member of the Electricity Distributors Association. Mr. Haines serves as the Sector Chair for the United Way of Greater Toronto's public service sector fund raising, and is actively involved with charities throughout Toronto.

GREEN OVATIONS

Innovations in Green Technologies

Integrating renewable energy into the grid

Automated Management System (AMS) Aimed to Increase PV Plant Productivity

By Lino Picheo, President, Staer Sistemi

A rapidly increasing availability of energy at reasonable prices is one of the key issues for the development and interest in renewable energy. The deterioration of local and global environmental conditions and increasing recognition of the threats posed by greenhouse effects have become the driving force towards the development of energy alternatives and improvements in the efficiency of energy use. There is currently a paradigm shift towards the use of Renewable Energy Sources (RES) even with the knowledge that grid instability can increase with renewable energy grid integration. Thus, the integration of energy generated from renewable sources into the electricity grid can pose significant challenges for both the grid manager and the producer. When the percentage of energy generated from renewable sources becomes significant, such as for a local utility, the energy operator may find that issues will arise with regard to the grid stability and the quality of distributed energy in terms of voltage sag and frequency fluttering.

For the RE (Renewable Energy) producer, given the relative youth of the market, and often the lack of industrial proficiency in automation and instrumentation strategies, it is difficult to implement a proper method of monitoring and control, which is crucial for efficient operation of the plant. An automation based management system relieves the human operator from routine processes by interfacing with a computer, thus resulting in a man-machine interface system.

Can an AMS help?

Usually an AMS is that system (or subsystems that come together to produce the result), which validates and supports plant operations, offering support for daily management and troubleshooting of problems. In some robust cases, an AMS also provides support for all the business processes that trigger the onset of an anomaly. In other cases, AMS is mainly intended to support the 'long-term health' of the plant and is less versatile regarding a continuous tune-up of plant productivity.

However, if we look at the particular business of electricity generation from renewable here, the technical and sales sides are coordinated and synchronized in a continuous process that can't be separated (at least for the moment).

This condition is not different from those of prepaid telecommunications services where downtime or quality of service turns into a quantifiable loss of revenues.

Since a significant part of the theoretical elaboration about AMS takes place on telco standardization bodies, it will be appropriate to refer to this scenario in order to better frame the subject.

According to TM Forum Business Process Framework definitions, we have a pretty broad set of functionalities under the umbrella of Performance Management Program. Most of those are related to accounting, billing and collection of revenues, and in general are off-line activities. However, if you look under the Assurance vein, you will find some concepts as we look for: Service Quality Management and related Resource Performance Management.

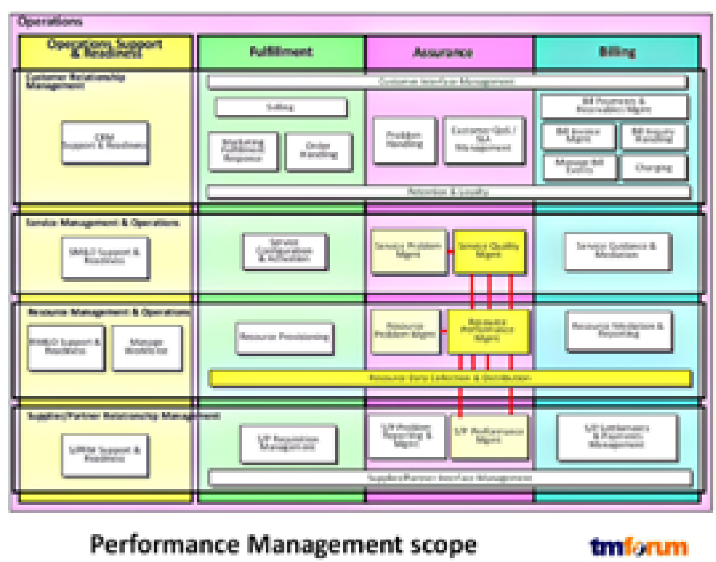


Fig 1 TM Forum Performance Management Program

These kinds of applications emerged some years ago as Performance Monitoring and have already found some diffusion in the market of renewable energy.

After examining AMS in the industrial standard perspective, we need to take a look at an actual Photovoltaic (PV) Performance Monitoring system.

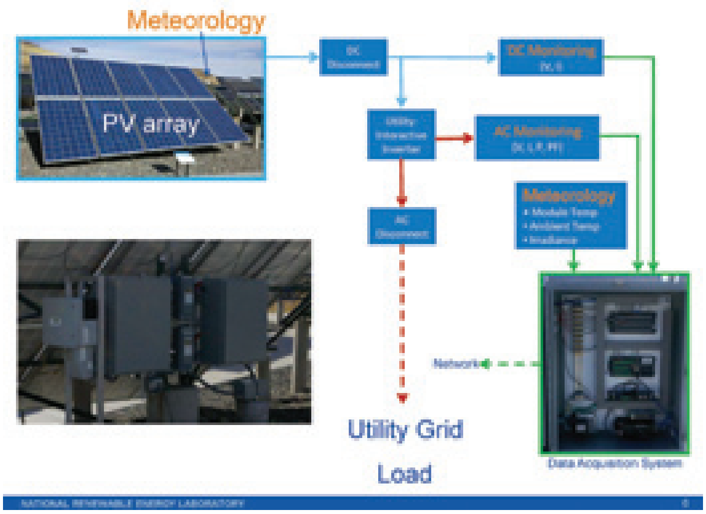
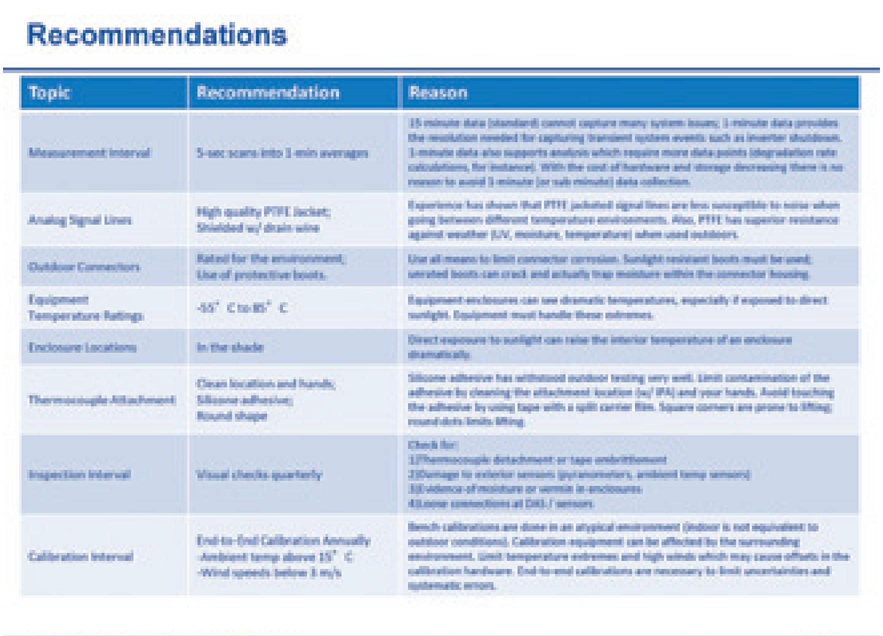


Fig. 2 A PV system monitoring and with the essential components (courtesy of NREL)

This is conceptually a pretty simple application, performing a real-time continuous comparison of the actual production. We will need a rather dynamic and specific benchmark of the plant production capabilities – something capable of estimating exactly how much energy the plant under healthy conditions would produce in the actual weather conditions. As a technical synopsis, we will use a mathematical model and a data set in order to supply variables for the simulation.

Both European and US standardization bodies and research organizations have expressed regulations and recommendations that represent an excellent starting point regarding our investigation into PV Monitoring systems.

In particular in the U.S., NREL (National Renewable Energy Laboratory) (see Fig 3) publishes a summary of such as ranges from the suggestion of optimal intervals of sampling data to the recommendations of installation and type of electrical and weather sensors.



Recommendations

Topic	Recommendation	Reason
Measurement Interval	5-sec scans into 1-min averages	15 minute data (standard) cannot capture many system issues; 1-minute data provides the resolution needed for capturing transient system events such as inverter shutdown. 1-minute data also supports analysis which require more data points (degradation rate calculations, for instance). With the cost of hardware and storage decreasing there is no reason to avoid 1 minute (or sub minute) data collection.
Analog Signal Lines	High quality PTFE Jacket; Shielded w/ drain wire	Experience has shown that PTFE jacketed signal lines are less susceptible to noise when going between different temperature environments. Also, PTFE has superior resistance against weather (UV, moisture, temperature) when used outdoors.
Outdoor Connections	Rated for the environment; Use of protective boots.	Use all means to limit connector corrosion. Sunlight resistant boots must be used; unrated boots can crack and actually trap moisture within the connector housing.
Equipment Temperature Ratings	-55° C to 85° C	Equipment enclosures can see dramatic temperatures, especially if exposed to direct sunlight. Equipment must handle these extremes.
Enclosure Locations	In the shade	Direct exposure to sunlight can raise the interior temperature of an enclosure dramatically.
Thermocouple Attachment	Clean location and hands; Silicone adhesive; Round shape	Silicone adhesive has withstood outdoor testing very well. Limit contamination of the adhesive by cleaning the attachment location (w/ IPA) and your hands. Avoid touching the adhesive by using tape with a split carrier film. Square corners are prone to lifting; round dots limits lifting.
Inspection Interval	Visual checks quarterly	Check for: 1)Thermocouple detachment or tape embrittlement 2)Damage to exterior sensors (pyranometers, ambient temp sensors) 3)Evidence of moisture or vermin in enclosures 4)Loose connections at DAS / sensors
Calibration Interval	End-to-End Calibration Annually -Ambient temp above 15° C -Wind speeds below 3 m/s	Bench calibrations are done in an atypical environment (indoor is not equivalent to outdoor conditions). Calibration equipment can be affected by the surrounding environment. Limit temperature extremes and high winds which may cause offsets in the calibration hardware. End-to-end calibrations are necessary to limit uncertainties and systematic errors.

NATIONAL RENEWABLE ENERGY LABORATORY 22

Fig 3 'Monitoring System Performance' (NREL/PR-5200-50643)

Scrolling recommendations show that measures to support a system of PV Monitoring are rather critical, involved technologies and are not elementary. In general the design of an accurate PV Monitoring system is not a simple topic as will be more apparent hereafter.

PV Monitoring System Design

At Staer Sistemi, we approached the matter in late 2009 trying to invest decades of experience in AMS for client companies. 'Keep it simple' was our slogan but unfortunately that wasn't easily fitting the application.

We, in fact, started design from the DAS (Data Acquisition Systems) block (see Fig. 2) to discover that, according to published research papers,[1] the volatility of solar radiation at ground level mainly due to atmospheric turbulence was asking for a pretty fast sampling pace (5 second or less). That meant we would need our DAS to process a data stream in the range of several thousand measures per second (in Europe and especially in Italy 1 MWp (megawatt peak) plants were the average size and our customers were planning up to 5 MWp). After some design tests using standard web application frameworks we weren't able to reach an acceptable quality standard. At the same time the client's internal large caliber software system was out of the scope. We adopted an industrial, yet modern, low-weight SCADA (supervisory control and data acquisition) software package – PcVue 10.0 from Arc Informatique. From that point on, we found that it made the design process easier to manage and the development of our EMSS (energy management support system) straightforward.

Modeling a complete plant

A complete PV plant consists of chained subsystems:

- the photovoltaic generator (panels in series and parallel)
- inverters (which are distributed or centralized)
- transformers (in the case of installations connected in MT to the grid)

A model design allows each subsystem to be managed separately but also takes into account how the systems are operating together as one cohesive entity. Many mathematical methodologies are available related to the physical reality of devices. Usually we discern using physical or empirical techniques (the latter comprising heuristic or statistical approaches). Hybrid methodologies can also be applied.

PV generator modeling

At Staer Sistemi, we opted for a hybrid approach based on physical modeling and some empirical functions. Those were helping to take into account the variance of solar spectrum during the day and the angle of incidence of the radiation on the panels' surface as well as accurately modeling separate contributions of the direct and diffuse radiation – that was important to accommodate various operating conditions and PV technologies such as Amorphous Silicon (aSi) and other thin film types.

Such an investment of R&D resources was necessary as each component of PV generator (single panels and strings of panels) contributes marginally to the global production. Simulation of energy production must be very accurate to allow discrimination of any malfunctions of individual panels inside strings.

The model for Cristalline Silicon (cSi), which was developed at the University of Rome Tor Vergata, showed remarkable accuracy. Since any specific measure on the panel's electrical figures (data supplied by the manufacturers) were economically sustainable. This allowed the application of a novel numerical technique of retro-tuning of model parameters, developed to manage inaccuracies of panel data sheets.

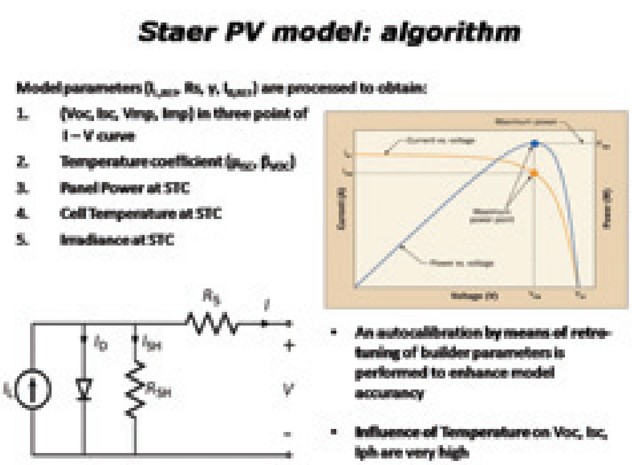


Fig 4. Staer Sistemi PV generator hybrid model

Modeling inverter

The inverter has adopted an empirical model that reproduces the operating characteristic curves supplied by the manufacturer through a simple input-output matrix. Alternatively, in addition to or to correct the manufacturer information, the model can use data derived from tests performed by specialized magazines (i.e. Photon International) or credited third party labs. That simple approach was capable of detecting the lack of efficiency or defects in MPPT (maximum power point tracking) functionality of inverters and allowed an accurate picture of true inverter capabilities in marginal conditions despite manufacturers' data claims.

Modeling transformer

The system finally implements a physical model of the transformer starting again from the data provided by the manufacturer. Losses, such as temperature of the package windings (detected through the appropriate sensor), are taken into account. Core eddy currents and related phenomena were also found to impact efficiency.

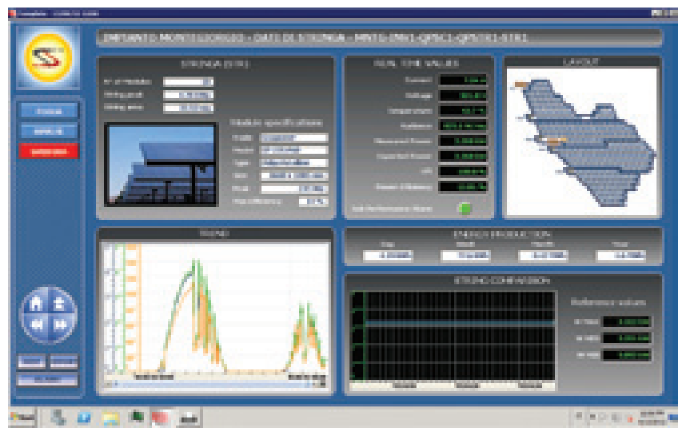


Figure 5: Analysis of weather-related changes on performance"

Comparison and Performance Indexes

The availability of a model for each subsystem and the availability of Meteorology data and Input/Output Electrical Measures for each block (PV panels where the energy input is solar radiation) enable the system to draw a comparison between the actual performance and the elaborations of the models. The results are delivered through the adoption of a simple metric. This is actually the ratio (a 1 minute average of 5 sec samples) between the measured power and what the model has computed. We called that Local Performance Index or LPI. This ratio is very close to the instantaneous power conversion efficiency of each subsystem.

Accordingly, Performance Index (PI) represents the overall performance of the system and is calculated as the ratio between the energy sold to the grid (at utility meter) and input in DC power. The model of PV generator is calibrated correctly for the instantaneous weather conditions. PI is also the product of all LPIs.

Back to AMS

The Performance Monitor Module PMM of EMSS generates alerts that are filtered and treated much like any other system alarms and managed according to the classic functionality of any AMS. In fact, according to the degree of severity set up, the underperformance event can trigger alarms at the local or remote management stations by sending short message service (SMS) or e-mail, which will open Trouble Tickets, alert Workforce Management applications, and so on.

Fig. 6. PcVue-based GUI's

The future is now

In the opening we mentioned the problems that are associated with distributed renewable generation and that are common with other intermittent source or load scenarios that affect electric grid management.

What emerged in Europe and in the U.S., after a wide debate on a possible approach to the problem or even a temporary solution, was the introduction for producers of some incentives mechanisms (or even penalization policies) concerning production forecasting.

In this regard EMSS comprises a module of Production Forecasting that, when appropriately supplied with weather data can offer very accurate prediction in the 24 to 72 hour range. There are many organizations that can provide an accurate forecast in the format required by the system.

The functionality has been developed building upon the already described PMM. In practice that software module is fueled with the weather forecast data based on irradiation, temperature, and wind speed (this latter to calculate the PV cell temperature in the absence of back panel thermal sensor readings). The granularity of forecast data can be numerically pushed up to the minute matching real data. Every aspect is in fact conceptually the same as true production conditions.

Forecasted PV generator production (if no relevant problems limiting production are logged) is in general calculated with the LPI of the previous day to take in account the actual 'health' condition. The process is repeated along plant subsystem chains.

Just in the case of electricity production that is only partially sold to the grid, the production forecast obtained would need to be corrected along with the local consumption forecast.

An additional revenues venue

According to the Federal Energy Regulatory Commission, Demand Response (DR) programs are intended to stimulate some planning in the electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time. DR incentive payments are designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. Lower electricity use does not exclude local production being a more general concept.

In our case of interest, DR initiatives and electric utilities are offering a sort of partnership whereby the economic equivalent of the costs a utility should sustain, for energy production in particular conditions, end up being fully paid to the PV (or other renewables) producer (or common customer most of the time) for their capabilities to schedule the amount of their consumption, production, or both, in a precisely planned way.

In practice, the DR incentives can be particularly advantageous during periods of maximum stress to the power grid – usually central hours of summer days. This period is coincident with the maximum production capacity of PV systems. The eligibility of DR programs for production from renewable sources may have some restrictions.

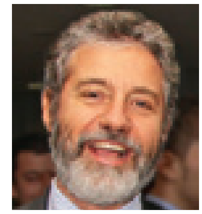
Conclusion

For the RE producer, the availability of a sophisticated AMS based on industrial grade SCADA software, such as PcVue, that is capable of effectively tracking the production performance, can help to increase the plant's bottom-line. In many cases this has been proved to be greater than ten percent annually.

The opportunity to enroll in increasingly popular DR programs through the Product Forecasting with Staer Systemi EMSS, can qualify PV energy producers with additional income.

[1] V. Badescu (Ed.) Modeling Solar Radiation at the Earth's Surface Recent Advances 4y Springer

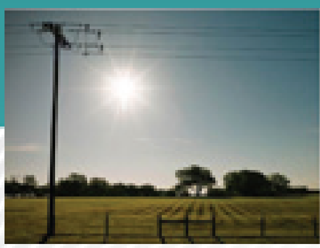
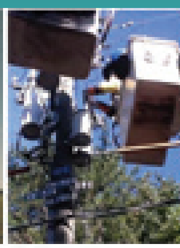
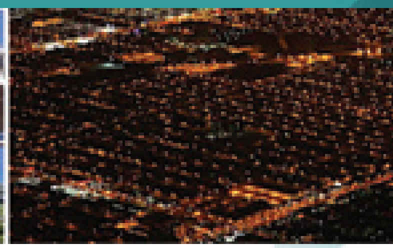
About the Author



Lino Picheo is President of Staer Sistemi, a SCADA solutions systems integrator based in Italy. The company has expertise in renewable energy, oil & gas, transportation, and water industries. Lino has worked for CPG (Consultancy & Project Group), Smarten Software, and Sun Microsystems

Why Accuracy Matters!

Factors that Influence the Accuracy of Metering Data & why they Matter

By Jon Bickel, PE

Why Accuracy Matters

There are over 6.2 million miles (10 million kilometres) of three-phase and single-phase distribution circuits in the United States and metering data provides utilities with the only 'real-time eyes and ears' into the performance of their systems.

Accurate measurements of electrical signals are essential to:

- improve reliability
- increase energy efficiency and conservation
- manage operations
- promote asset management
- identify cost savings opportunities and solve problems

Two components (sensors and intelligent electronic devices) are required to gather data from medium voltage distribution systems. Each component introduces inaccuracies as the primary signal is converted into a digital signal. It is important to select metering components that minimize or eliminate potential inaccuracies. This will provide more confidence in decisions that are made based on metering system data. This article identifies factors that can influence the accuracy of metering data as it is transformed into digital information – and explains why they matter.

The Significance of Accuracy

Accuracy seems to be a straightforward term and is frequently employed in the world of distribution system sensors and metering. **Accuracy is the degree of closeness that the meter can achieve with respect to the true value of the measured quantity.** While accuracy is commonly accepted at face value, it is far too important a concept, and has too many repercussions, for insufficient consideration.

The primary objective of electric metering devices, such as sensors and Intelligent Electronic Devices (IEDs), is to accurately capture and reproduce data from a primary signal (e.g., magnitudes and phase angles) so that the best decisions can be subsequently made. While accurate metering data can facilitate system improvements, inaccurate data can produce ineffectual or even counterproductive results.

Consequences of Inaccurate Metering Data

The existence of one or more of these issues can negate the potential value of a high-quality, well-designed distribution metering system.

- **Loss of confidence in distribution system:** If metering data is conflicting or historically inaccurate, operators may not know what is correct and ignore the metering system data.
- **Decreased reliability and efficiency:** Inaccurate meter data veils the actual operating parameters and reduces the ability to optimally operate the system.
- **Higher direct costs:** Inaccurate consumption readings at meter results in billing errors and impacts revenue.
- **Higher indirect costs:** Erroneous assumptions based upon inaccurate metering data can influence decisions to increase spending on nonexistent problems.
- **Misallocation of resources:** In the process of measuring and converting the primary signal into a digital signal, valuable information may be lost – resulting in erroneous conclusions and time lost in trying to identify root causes.
- **Safety concerns:** Overloaded conductors or service equipment may not be identified – resulting in electrical or fire hazards.

When measuring a signal and communicating its parameters to the end user, there are several factors that can introduce inaccuracies into the data. These inaccuracies can lead to problems for the end user – from misallocating resources by pursuing faulty assumptions to unwittingly forfeiting beneficial opportunities.

Because the sensor and IED are discrete components that are typically designed, manufactured, and sold independently, each receives its own accuracy rating from the manufacturer. This is a very important consideration when pairing a sensor with an IED because the accuracy of either component can adversely impact the combination of the two.


Okay. We admit it.
A pretty girl. Racing.
Shameless.
Please forgive us, but if that's what it takes to get your attention; if that's what we need to do to help you understand the importance and wisdom of converting to low-voltage metering, so be it.
From your very first VTPack™, you'll...
• Virtually eliminate costly meter failure
• Protect against lightning surge
• Eradicate AMI/AMR signal loss errors
• Regain revenue lost to signal errors and meter faults
• Cut transformer install time to a fraction
• Greatly reduce risk of flash-over, employee injury or death
You'll wonder why it took so long. But don't thank us.
Thank Ginger.
TSTM
TWO SOCKETS-TWO METERS inc
www.ts-tm.com
"I personally guarantee our products. Try any or all, risk free."
Greg May
President, TSTM
Fully AMI/AMR compatible, including TWACS®.
See a short installation video at www.ts-tm.com
TSTM VTPack™
Ratio: 2.5:1
TWACS® is a registered trademark of Aclara®, an ESCO Technologies Company.


Ginger, Miss May
Open for
Pin-up

Metering System Components: Sensors and Intelligent Electronic Devices

Two primary components make up the core of data collection on utility systems: sensors and intelligent electronic devices (IEDs) – as shown in Figure 1.

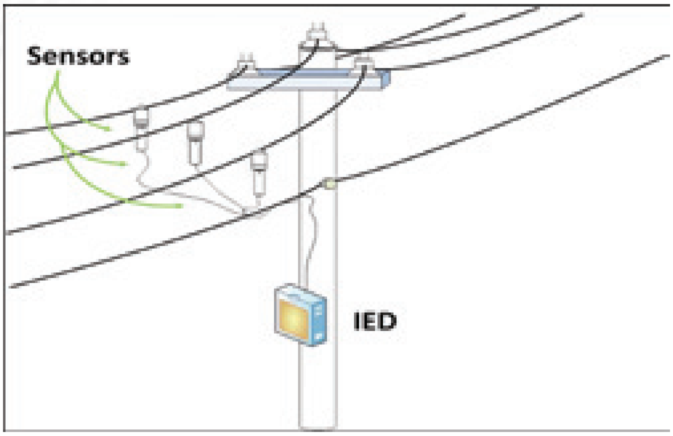


Figure 1

The purpose of a sensor is to safely and accurately reduce a primary signal's magnitude while keeping its characteristic qualities intact. The IED then converts the representative analog sensor signal into digital data, which is then easier to analyze, manipulate, communicate, and store.

There is a conversion that occurs in each of these two components and the representative signal is degraded to some extent as it is passed through the sensor and IED.

As the primary signal passes through the sensor, a change is induced in the sensor. A representative analog signal, which is proportional to the primary signal, is produced.

It is impossible to generate a perfect characteristic correlation between the primary signal and the sensor's representative signal, so the resulting sensor output signal is modified to some degree. Sensors often introduce inadvertent filtering, noise, phase shifts, and magnitude imprecisions into their output signals. External factors such as temperature, humidity, and burden can produce additional influences.

After the sensor output signal is acquired from the primary signal, the sensor output signal must be converted into a digital format by an IED. The post-conversion benefits of converting analog signals, such as voltages and currents, into digital formats or signals include easy storage, simple reproducibility, higher noise immunity, and increased flexibility.

Similar to the process of creating the sensor output signal, the process of creating a digital representation of that signal (and by extension, the primary signal) produces some degree of alteration or degradation in the resulting signal.

Since a digital representation is produced by discrete samples of the analog signal (Figure 2), it is evident that a loss of information occurs in the period between samples (the inter-sample interval) during the transformation into a digital signal.

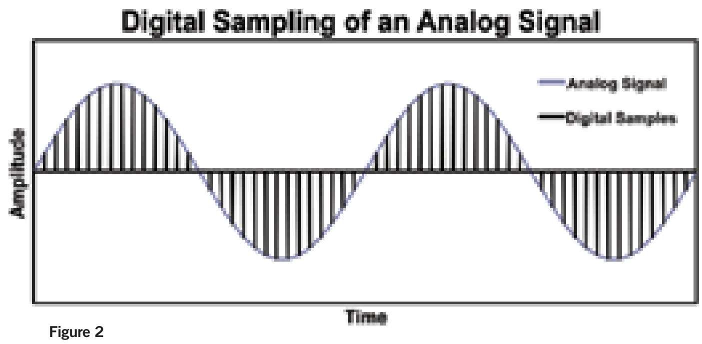


Figure 2

Sensor Technologies

Two broad sensor technologies – conductive sensors and optical sensors – are employed to capture voltage and current characteristics from medium voltage distribution systems and convert them into representative analog signals for the IEDs.

- Conductive sensors use voltage or current as the representative analog output signal to be passed to the IEDs.
- Optical sensors use light as a representative analog output signal to be passed to the IEDs.

It is important to consider the influence that each of these technologies can have on the primary signal.

Figure 3: GE Voltage & Current Transformer (PT/CT)

Although there are several other conductive sensor technologies available (e.g., Rowgoski coils, voltage dividers), the most prevalent types of conductive sensor technologies used in medium voltage distribution systems are instrument potential transformers (PTs or VTs) and instrument current transformers (CTs) (Figure 3). Instrument transformers have long been used to measure ac power parameters, and their performance and accuracy depend on correctly using them in a metering system.

Conventional Instrument Transformers

Because instrument transformers use current flow through windings to produce a ratio of the primary signal to a secondary signal, they are subject to the physical constraints of those elements.

The primary and secondary windings of voltage transformers share a common core, similar to a standard service transformer, and the output of the secondary windings are proportional to the primary windings.

BGE
A Constellation Energy Company

Baltimore Gas and Electric

(BGE), a subsidiary of Exelon Corporation, serves more than 1.2 million electric and more than 650,000 gas customers in Central Maryland. Its distribution system includes 24,000 miles (38,600 kilometers) of electricity transmission and distribution lines and more than 7,000 miles (11,260 kilometers) of gas main.

"Having accurate field data is extremely important when making decisions that are critical to customers and the business," says Aleksander Vukojevic, Engineering Consultant for Smart Grid Distribution Automation and Technology with BGE.

"For Conservation Voltage Reduction (CVR), we need accurate voltage measurements from all capacitor bank controllers, and other field sensors," Vukojevic notes.

"Voltage range for residential customers in the U.S. is small (114 V to 126 V), and the objective of CVR is to keep the voltage within the lower portion of the range in order to minimize energy consumption.

"BGE capacitor bank controllers use voltage from 1 kV potential transformer as a reference. Moving forward, before we can roll out any device on our system full scale, we must have the confidence that we have very accurate voltage and current readings, which will enable us to use the CVR algorithms more efficiently to help meet our CVR objective."

Unlike the voltage transformer, the current transformer is connected in series with the phase conductor and produces an output current that is proportional to the flow of current through the conductor. A conventional voltage transformer produces a known secondary signal that is typically either 115 or 120 volts at the rated primary voltage. Likewise, the conventional current transformer typically produces five amperes in the secondary signal when the rated current is flowing through the conductor.

Several factors can influence theaccuracy of PTs and CTs including burden, temperature variation, signal range, and frequency components present. Instrument transformers are selected for specific purposes, such as metering or protection, and the misapplication of instrument transformers can distort or attenuate important information contained within the primary signal.

Even the best instrument transformer will experience ever-increasing attenuation of high frequency components, such as harmonics, due to their increasing impedance at higher frequencies ($X_L = 2\pi fl$). In short, it is necessary that the instrument transformer's design, intended application, interacting equipment, and environmental constraints be well understood for a successful deployment.

Optical Sensors

Optical sensors use a different method to produce a representative analog signal from the primary signal and convey it to the IED: light.

Light waves are electromagnetic waves that have both electric and magnetic fields that oscillate at right angles to each other. As polarized light is passed through the electromagnetic (EM) fields that surround conductors, it is rotated by an angle that corresponds to the magnitude of the field. The rotation of the polarized light will vary as the EM field varies so that a representative signal can be derived by measuring the degree of rotation as a function of time.

Figure 4: Optisense MV Optical Current & Voltage Sensors attached to 3 Phase Distribution Lines

Factors that can influence the accuracy of optical sensors include the light's wavelength, transmission medium, temperature variations, and neighboring EM fields. In most cases, design considerations can mitigate a significant portion of any potential signal degradation in the conversion to a representative analog signal. Calibration of the sensors over the operational temperature range also improves the veracity of the representative signal. Using a technology that measures the degree of rotation in polarized light allows a wider operating range without experiencing saturation.

Intelligent Electronic Devices (IEDs)

The analog (continuous-time) signals produced by the sensors are sampled and converted into a digital (discrete-time) signal by an IED. Any inaccuracies introduced by the sensors are passed into the IEDs where additional inaccuracies are introduced.

Analog-to-digital converters (ADC) are hardware components used in IEDs to transform the analog input voltage and current signals into approximate digital representations. The ADC takes discrete samples or measurements of the analog input signal. This provides an approximate magnitude of the signal at the point the sample was taken. The ADC takes these samples at a pre-determined periodicity called the sample rate (samples/second) or sample frequency (1/sample rate).

Both the vertical (magnitude of the signal) and horizontal (sample rate over a period) dimensions must be considered when attempting to accurately convert an analog waveform into a digital waveform. An ADC can provide a fixed number of values, determined by the ADC's resolution, over the range of the analog signal's values. Higher resolution ADCs will more accurately represent the analog signal's real value.

For example, an 8-bit ADC provides 2^8 (256) different values over the analog signal's range. Obviously, a higher resolution ADC will provide more values (and better accuracy) over a given range.

Analog signals provided by the sensors are likely to have multiple frequencies embedded in the signal (in addition to the 60 Hz signal) due to the arbitrary nature of medium voltage distribution systems (e.g., load types, operational parameters).

For example, events such as capacitor switching produce additional frequency components or ringing (Figure 5). In order to accurately capture the embedded high frequency components in the digital format, the sample rate of the ADC must be greater than twice the highest frequency of interest.

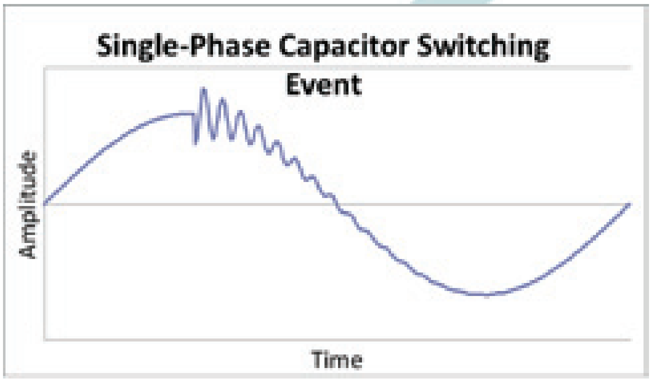


Figure 5: Single Phase Capacitor Switch Event

If the 15th harmonic is the highest frequency of interest, the ADC must sample at a rate greater than 1800 Hz (2 x 15th x 60 Hz). The sample rate of the ADC determines the highest harmonic that can be captured by an IED. Conversely, not sampling the analog signal at a high enough rate (under-sampling) results in lost information and inaccurate data from the IED.

Aliasing

Under-sampling analog signals in the conversion process also produce an error known as aliasing. Aliasing occurs when there are frequencies in the analog signal that are greater than half the sample rate of the ADC. An illustration of the consequences of under-sampling is the wagon wheel effect. In old movies, an optical illusion occurs when the wheels of a rapidly moving wagon appear to be turning slowly forwards or backwards. This effect is produced by having a slower camera frame rate compared to the high speed of the wagon wheel.

Aliasing in IEDs can be mitigated by incorporating a low pass filter on the input to eliminate frequencies above the useful range of the ADC, or by increasing the sample rate of the ADC to at least twice the highest frequency present on the analog signal. Additional factors can generate inaccuracies in digital data. Some of the factors are:

- non-synchronous sampling
- algorithm errors
- noise
- blind sampling
- component aging
- stability of the reference

Aliasing

A signal is synchronously evaluated by two IEDs. The first IED ("IED_{16}") has a sample rate of 16 samples per cycle; the second IED ("IED_{32}") has a sample rate of 32 samples per cycle. A large magnitude 9^{th} order harmonic is injected into the signal and a waveform is captured by both IEDs. Figures 6 and 7 below illustrate the waveforms from IED_{16} and IED_{32} respectively.

The waveforms are noticeably different due to the respective IED sample rates and the presence of the 9^{th} harmonic component. Figures below demonstrate a textbook example of the aliasing effect. What is measured correctly as a 9^{th} order harmonic component by IED_{32} incorrectly determined to be a 7^{th} order harmonic component by IED_{16}. Under-sampling the 9^{th} order harmonic component by IED_{16} permits it to be aliased down to a 7^{th} order harmonic component. In most cases, different load types produce the 7^{th} order and 9^{th} order harmonic components, so troubleshooting the problem and locating the harmonic source would be difficult because of IED_{16}'s sample rate.

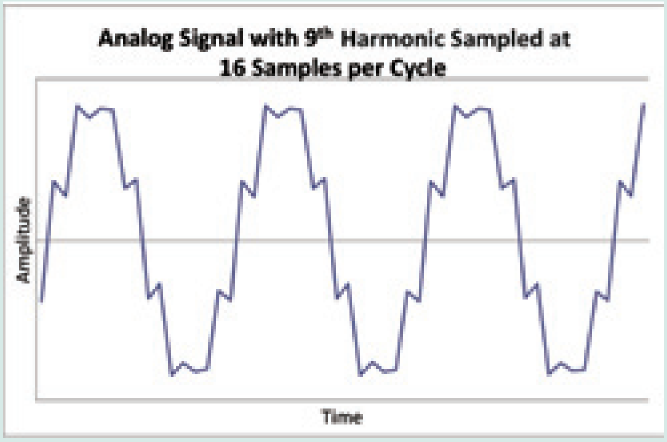


Figure 6: IED_{16}

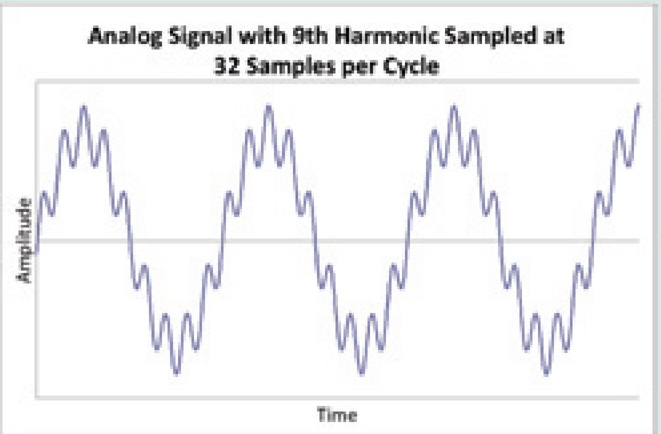


Figure 7: IED_{32}

It is important to understand the sources of inaccuracies in metering systems so that steps may be taken to reduce their effects. The conversion of an analog signal into a digital signal typically produces inaccuracies by omitting, creating, repositioning, or eliminating data. Because data from every digital meter includes some degree of inaccuracy, the end user must determine their acceptable level.

Accuracy Effects of Combining Sensors and IEDs

Because the sensor and IED are typically designed, manufactured, and sold independently, each component receives its own accuracy rating from the manufacturer. This is a very important consideration when pairing a sensor with an IED, because the accuracy of either component can adversely impact the combination of the two.

Table 1: Combined Accuracy of Sensor and IED

Sensor Accuracy	IED Accuracy ±0.2%	±0.3%	±0.5%	±1%	±2%
±0.2%	0.28%	0.36%	0.54%	1.02%	2.01%
±0.3%	0.36%	0.42%	0.58%	1.04%	2.02%
±0.5%	0.54%	0.58%	0.71%	1.12%	2.06%
±1%	1.02%	1.04%	1.12%	1.41%	2.24%
±2%	2.01%	2.02%	2.06%	2.24%	2.83%

Table 1 illustrates the effects of combining sensors and IEDs with differing accuracies. For example, choosing a sensor with ±1% accuracy to interface with a ±0.2% accurate IED will result in a combined accuracy of ±1.02% for the pair. Choosing a sensor with ±0.5% accuracy to interface with a ±0.5% accurate IED will produce a combined accuracy of approximately 0.71%.

Ultimately, the accuracy with which a primary voltage or current signal can be digitally reproduced (through both the sensor and IED) is determined by a combined accuracy that is worse than that of either individual component.

While a few manufacturers sell total metering hardware solutions that provide combined accuracy for sensors and IEDs, the majority do not. Therefore, it is important for the end-user to account for the combined effects on accuracy of *both* the sensor and IED when selecting a metering system.

Conclusion

Accurate measurements of electrical signals are essential to pinpoint energy savings opportunities, improve reliability, and identify and solve problems. The two components (sensors and IEDs) are required to gather data from medium voltage distribution systems. However, each component introduces inaccuracies as the primary signal is converted into a digital signal. It is important to select metering components that minimize or eliminate potential inaccuracies. Doing so provides more confidence in the decisions that are made based on data provided by the metering system.

References:
"Sampling Pitfalls in Digital Power Meters," Jon Bickel, Ronald Carter, Schneider Electric, Power Quality Exhibition & Conference Proceedings, October 2005.
"Manual of Instrument Transformers, Operation Principles and Application Information," GET–97D, General Electric Company, Meter and Instrument Business Department, Somersworth, N.H. 03878.
"Instrument Transformers, Technical Information and Application Guide," 1VAP420003-TG December 2004 Rev. A, ABB Inc., 3022 NC 43 North Pinetops, NC 27864.
"Platts 2013 UDI Directory of Electric Power Producers and Distributors," 121st Edition of the Electric World Directory, Ellen F. Giles, Editor, Kathy F. Brown, Assistant Editor, Platts (A Division of McGraw-Hill), Two Penn Plaza, New York, NY 10121.

Figure 2: http://cnx.org/content/m15655/latest/

GE PT/ CT
http://www.directindustry.com/prod/ge-transformers/outdoor-cast-resin-medium-voltage-transformers-22346-675927.html

About the author

Jon Bickel is a professional engineer, IEEE Senior Member, and Senior Edison Expert with a specialization in Power Quality and Reliability Metering Instruments. Formerly with TXU and Schneider Electric, Jon is the holder of more than 30 patents. Currently Jon serves as Vice President of Product Management with Optisense Network, LLC, a designer and producer of medium voltage technologies for Smart Grid applications.

Forecasting a Natural Disaster

How GIS and weather predictions help utilities recover in the aftermath

By Danny Petrecca, Schneider Electric, Director of Product Management, Enterprise GIS

When a utility is faced with a natural disaster, tools such as an outage management system and distribution management system are traditionally leveraged to get service back up as quickly as possible. But as electric utilities confront disasters that impact increasingly larger and denser populations – from Hurricane Sandy to California wildfires – its natural disaster management plan cannot begin the first day after the danger has passed: The urgent need to repair critical infrastructure and deliver power to customers is too great. Instead, the plan should first identify the resources a utility needs to forecast the disaster, prepare the network and customers for the impacts, and resolve outages and damage as quickly as possible.

In fact, more and more utilities are leveraging tools not typically used in outage scenarios to comprehensively protect customers and infrastructure better, and to work with first-response crews and governmental agencies to speed up recovery. This article will examine how two of the most prominent systems – GIS and weather forecasting technology – can work together to prepare the network for a disaster and recover in the aftermath.

More than maps

A GIS system provides one of the most important tools a utility needs when responding to a major disaster: enterprise-wide access to readily available, highly accurate mapping and data on real-time asset conditions. This becomes even more critical as an increasing number of utility workers retire from the workforce and with them decades of data including the thorough and historical understanding of the network and its risk points, walk out the door. This information may never have been captured digitally, but instead remains in the brains of a talented workforce or locked away on paper, with no efficient or systematic way of transferring the accumulated years of intuitive knowledge.

With an enterprise GIS system, information can be updated across the entire organization immediately. This is imperative not only for day-to-day operations, but especially when preparing for and responding to natural disasters. For example, as hurricanes, fires, floods or other weather events approach a city, utilities can leverage their GIS to assess the risk to critical infrastructure and prepare for damage-related outages, as well as communicate with customers to help them prepare for extended outages and keep them informed on the progress of the restoration. Service can be adjusted to avoid added risk from damaged assets. These shutoffs can be isolated to minimize the number of affected customers because of the accuracy of the database and advanced network analysis tools. Similarly, the real-time data allows the utility to know where it can quickly restore service or how to reroute services around damaged assets in the meantime to keep the lights, gas, internet, and water on.

The mapping and asset identification benefits of the GIS system are just as important after a disaster hits. For instance, if a plane or helicopter is surveying damage overhead and spots a downed utility pole, the GIS can tell the worker the size and type of the pole, what equipment is on it and how customers downstream may be affected by the damage. This is powerful information for a utility working hard to reroute or reconfigure the network to get customers back online, or at least manage expectations as to when reliable power is running again.

Enterprise GIS helps utilities prepare for and respond to major disasters by ensuring data is both highly accurate and easy to rapidly share

This asset data is also important for damage assessment by helping to determine the amount of material lost and the associated cost. A utility can compare the needs to the materials it already has in stock to get things back up and running, or make a specific request of nearby utilities.

Enterprise GIS was a valuable resource to many utilities during the aftermath of Hurricane Sandy, when millions of customers were left without power. Several utilities provided outage maps on their websites, and some even had them up and running before Sandy hit. This allowed their customers to prepare and plan for their expected days without service.

Many utilities, however, never provided this information and were criticized by the government and the public for being unprepared.

As John Wycoff, director of engineering at New Jersey Natural Gas, stated, "After our dedicated employees, the biggest reason we were able to restore service so quickly was our GIS system and Schneider Electric's ArcFM. A typical outage could be a hundred homes and a few thousand feet of main. Here we were facing 30,000 homes and over 275 miles of main. Without these tools to analyze and manage the restoration process, we could never have responded so quickly."

Forecasting disaster

Adequately preparing for a natural disaster is just as important as the response to it. Utilities need to know where and when damaging weather conditions will impact their territory to execute a faster response to service interruptions. The right forecasting service will provide reliable, precise weather data – including real-time lightning detection and customizable alerts – to help utilities prepare and restore power more quickly after a disaster. To help pre-position crews, predictions may show a color-coded threat level to the service territory for the next 60 minutes, and storm tracking will display the storm's estimated arrival times to a utility's assets in its path.

This helps utilities plan ahead, ensure enough crews are mobilized, and position them properly with equipment already set up and ready to respond to the predicted damage. For example, real-time, animated lightning strikes can pinpoint where assets may be in danger and instantly let operators know whether the strikes are intensifying or subsiding. If the weather forecasting service has high-resolution, street-level mapping, it can work with the GIS system to provide the ultimate view of conditions and how the weather is affecting key infrastructure to help operators make better-informed decisions about response crews and operations.

In the event of a natural disaster, such as a hurricane, a utility needs to have the best forecasting expertise at its fingertips to determine exact landfall location, expected precipitation, wind speeds, and more. With a top-rated weather forecasting service, a utility may be able to procure the resources it needs more quickly, including mobilizing additional field crews and preparing surrounding utilities to help. The forecasting service should include long-range forecasts and hourly ones that include a confidence ranking to help operators prioritize resources for the response. Prioritizing is key when preparing for a disaster to ensure that extra resources aren't wasting time and money where they are not needed.

After Hurricane Sandy, Tom Murphy, environmental compliance and business continuity manager for Unitil, a public utility holding company, noted, "It is possible to over prepare for a storm…By not listening to some of the hype, we avoided over-preparing, which is ultimately a cost-benefit to our customers."

More utilities are taking weather forecasting one step further by integrating historic weather data with their GIS, giving them predictive outage management scenarios and plans. If extreme weather events are more common in certain months or regions of the service area, the utility can better prepare in terms of staffing and infrastructure development. This is where the importance of weather forecasting comes in and where the combination of it and the GIS data can be the most powerful.

Collaboration during disaster

The combination of accurate weather forecasts and a GIS system can also be a tremendous asset to the greater community. Utilities may share data with fire authorities, emergency management groups, and public officials who assist them in planning and response. With large-scale disasters that require public safety crews to assess large numbers of threats, this data can be an indispensable tool for helping decision-makers triage the most critical areas and deploy resources.

An example of this occurred several years ago in San Diego as fires invaded the area. First responders were able to create maps of essential infrastructure with the local utility's GIS information. As fires approached a primary communication tower, a hub for all the main cellular carriers in the area, it threatened the communications network that all emergency responders were using. With the help of the GIS mapping service, responders were able to redeploy and prevent the loss of the tower that was essential to the ongoing disaster management effort.

Utilities can be an integral partner for public safety officials and first responders by sharing data to assist in planning response

Real-time data is also used in the event that crews from surrounding utilities are called to the area to help with recovery. When faced with lines of trucks and crews waiting for directions, a utility must be able to disseminate information quickly and accurately to maximize the extra resources. With the asset information from a GIS system and the real-time weather conditions and forecasts available in the back office and out in the field, additional service crews can quickly become part of the team and get to work on outage restoration.

Accessibility during the storm

Weather forecasting and GIS data is not as valuable if crews can't access it during a disaster because communications infrastructure is damaged or overloaded. Now more than ever, utilities are working to ensure that crews can access the GIS database via a mobile device, as well as record and update data safely and securely.

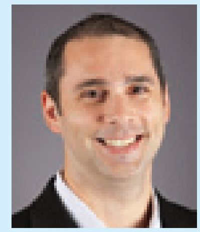
A variety of solutions are in production to provide alternative ways for field crews to access and record data, including greater use of mobile devices and developing cloud-based systems for uploads and downloads. Workers are now able to access and upload data wherever they can connect to a wireless internet or mobile network. This increases the security of data and the efficiency of crews by reducing the number of truck rolls to report in and collect new data and assignments. A flexible field crew can stay in the field and respond to new jobs as they come in. This is a huge advantage during disaster response – when every minute counts.

As these systems become increasingly integrated, customized and shared, utilities will innovate ways to use the advantages to meet their business challenges. Of all the significant benefits enterprise GIS brings to a utility, hopefully the job of disaster management is rarely needed. But when billions of dollars in infrastructure, hundreds of thousands of customers, homes, and businesses are at risk, the ability to aid in effective and rapid response is critical.

What's next?

Natural disasters will only have greater impacts as our population continues to grow, especially in urban areas. By further analyzing historic weather events, utilities' outage management can take more predictive elements into consideration. For example, by looking at previous hurricanes on the East Coast and where the highest winds have been, utilities can overlay that information with their most exposed infrastructure and predict not only where the next storm may have the greatest impact on infrastructure but where proactive measures can be taken, such as vegetation management or replacing older poles in these targeted areas.

As utilities examine all of their resources when preparing and planning a natural disaster response, enterprise-wide systems with real-time information, like GIS and weather conditions, will likely always play a central role. As the industry moves to integrate more systems and more historical data, our picture of the past will not only become clearer, but so will our path ahead for faster service and restoration after the storm.



About the author

Danny Petrecca is currently Director of Product Management for Enterprise GIS at Schneider Electric. He has a deep knowledge and experience with application of GIS technology to utility and communications industry business needs. His specialty is graphic work design in utilities. Danny has 13 years of experience in the geospatial industry.

Monitoring Underground Grid Assets with Wide-Area Wireless Networks

By Jason Wilson, SVP Business Development and Product Management, On-Ramp Wireless

The U.S. Department of Energy (DOE) has a lofty goal of reducing customer outage time or Systems Average Interruption Duration Index (SAIDI) by 20 percent by 2020. As a result of aging infrastructure and other factors, the average household and business experience over 120 minutes of electricity outage a year. This has a significant societal impact costing tens to hundreds of billions of dollars annually.

To achieve this reduction in outage time, the entire distribution grid needs to be monitored reliably. Even though many grid assets are still above ground today, assets are increasingly moving underground to improve reliability and environmental aesthetics, with some utilities having over 65 percent of their circuit miles below ground. In San Diego Gas and Electric's (SDG&E's) case, 70 percent of their circuit miles are below ground. However, the benefit of undergrounding also comes with challenges, including the fact that manually troubleshooting below ground circuits is extremely costly due to traffic obstructions, confined environments, and dangerous conditions like flooded manholes. As such, utilities not only want, but need, effective monitoring of these underground assets. To date, smart grid communications technologies have not been available to reliably service these assets.

Recognizing the need to improve electric distribution system reliability, and the associated benefit to the United States, the DOE is working with industry, national labs, universities and other groups to research, develop and demonstrate commercially viable solutions to modernize the grid and deliver the true measurable benefits of the 'Smart Grid.' One such initiative is the DOE 2012 Smart Grid R&D Program.

2012 Smart Grid R&D Program Objectives

One of the DOE 2012 Smart Grid R&D Program initiatives focused on the need for a cost-effective wireless communications solution for monitoring devices deployed in urban, suburban, and rural geographies, and installed in below-ground and other hard-to-reach locations. This initiative emphasized the ability to understand the wireless environment, and to accurately plan coverage for the more challenging coverage environments. Another of the DOE's key goals was to verify that wireless coverage reality matched predictions.

As such, the DOE selected On-Ramp Wireless's Total Reach Network to demonstrate a secure and reliable commercial solution that would monitor and detect outages in underground and other hard-to-reach distribution circuit locations. The Total Reach Network is a wireless communication system specifically designed to efficiently connect billions of hard-to-reach devices in metro scale and other challenging environments. Under the DOE grant, On-Ramp Wireless partnered with Schweitzer Engineering Laboratories to provide a wireless analog interface for fault circuit indicators (FCIs), with GridSense to provide smart transformer monitors (TIQs), and with partner utilities SDG&E and Southern California Edison (SCE) to deploy demonstration networks in their respective territories.

Challenges of Monitoring Underground Assets

Normally, continuous underground distribution lines are accessible roughly every 500 feet via vaults, manholes, handholes, or padmounts. These circuit access points can contain various types of devices including simple junctions, switches, transformers, and capacitor banks. Beyond the above ground RF challenges of clutter, interference, etc., the DOE study established that a wireless network must be able to compensate for up to 30 dB of additional penetration loss for extending the signal to underground monitoring points. The actual penetration loss was characterized during the DOE study with field measurements for the vault, manhole, handhole, and padmount locations.

A second challenge is accounting for static devices when deploying the network. Unlike planning for a cellular network where mobile devices in motion compensate for local area nulls, a wireless module deployed on a smart grid sensor is static at a single physical location for its entire lifetime. The traditional cellular network planning model, which is broadly used for smart grid network planning, has limitations when directly applied to devices that are physically stationary. This was a critical finding of this study. Based on thousands of DOE study data points, it is clear that the RF coverage of two deployed devices that are separated only by a matter of inches can be substantially different. This finding led the project team to test a similar concept – two available antennas on a single endpoint, separated by that critical distance of a few inches.

Incorporating antenna diversity, like dual antennas, at the endpoint significantly improves the reliability of wireless communications with the endpoint. Understanding this in detail has clear implications for endpoint design, density and placement of wireless infrastructure, and smart grid network planning.

Accurate Network Prediction is Critical

The ability to accurately predict network coverage is critically important in understanding the total cost of ownership of a prospective wireless smart grid solution. Coverage prediction is always statistical, but a 'good' model is one that is unbiased and has a small standard deviation when compared to actual measurements. RF propagation software cannot model every single building, tree, shrub, etc., so the goal is to continue improving such models with real-world measurements. The rich data collected during the DOE study enabled refinement and validation of a comprehensive smart grid wireless coverage prediction methodology. It leverages the existing cellular methodology where possible, and augmented that methodology where needed in order to improve prediction for static assets as well as for underground assets. The final proposed model is both intuitively credible, and more importantly, it accurately fits the measured data.

Execution of the DOE Study

The project team designed a technical demonstration to address key study objectives:

- Design and build a wireless communications network with minimal field infrastructure that reliably covers a mixture of potential asset locations like underground vaults two stories below grade, underground manholes and handholes, or pad mounted structures.
- Demonstrate monitoring for a variety of devices, including both battery powered and line-powered endpoints, as well as endpoints demonstrating both standard antenna configurations and antenna diversity.
- Remotely and reliably monitor underground grid assets, collecting periodic status reports as well as immediate alerts if a device detects an alarm condition.
- Track and record device monitoring results over 6 months, and with the results, develop full-scale network planning and deployment recommendations.

Launching the monitoring network quickly, the On-Ramp Wireless project team completed several deployment activities for both SDG&E and SCE demonstration networks:

- **Site Characterization**: Using the utility's training grounds, each of the proposed asset environments, including underground vault, pad mount enclosure, was evaluated for installation requirements and wireless penetration characteristics. A test device was used to measure the penetration loss covering an asset inside a given type of enclosure, and the network planning models were tailored accordingly.

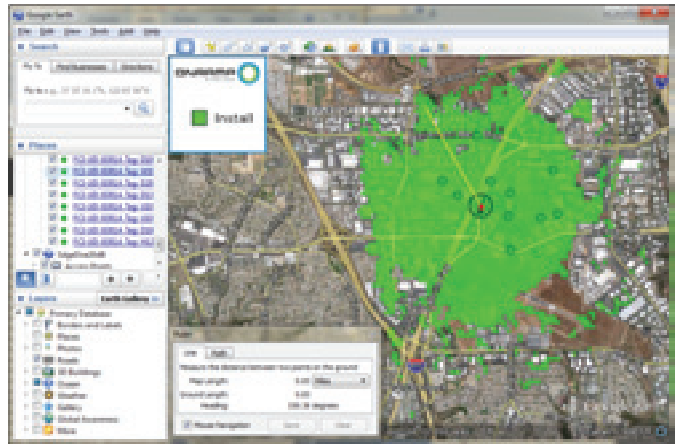


Fig 1: Potential AP site characterized in terms of underground reach

- **Access Point Site Selection**: Designing a dedicated DOE technical demonstration network required each utility to identify a superset of asset monitoring targets, and then identify potential Access Point (AP) sites for covering those assets. Based on ease of site acquisition and installation, and opportunity to select a range of valuable/viable end point locations, candidate AP locations were chosen. By identifying all utility assets in the surrounding area of a site, and then testing the actual coverage from the AP site to each type of asset location, the candidate site locations were then narrowed down. Due to the larger area and unique design of each underground vault, it was noted that the relationship of predicted to actual coverage measurements for underground vaults was more variable than for other installation locations. Final AP sites were chosen based on predicted ability to provide reliable communications for the maximum number of target assets.

- **Network Installation**: Both utilities elected pilot grade installations versus permanent commercial grade installations; hence, the APs were installed using free standing mounts, existing power, and existing backhaul services. Install time per AP was approximately 3 to 4 hours, which included full site verification upon installation. The field network was configured to be managed by the On-Ramp Wireless hosted back office solution, and the end-to-end network connectivity and performance verified. Combined, the SDG&E and SCE networks included:

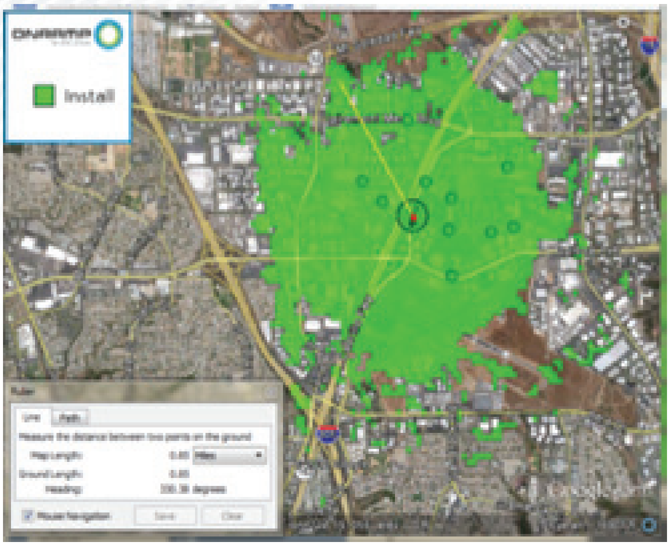


Fig 2: Non-penetrating On-Ramp Wireless Access installation

- Hosted access to the On-Ramp Wireless Total View network management, security, and infrastructure monitoring application suite.
- 8 On-Ramp Wireless APs, the only field installed infrastructure, with each AP covering underground assets up to 1 mile away
  from an AP.

- **Endpoint Installation**: Once the APs were sited, each utility selected various endpoints to reflect all variables faced in underground monitoring:

  - Locations for both Schweitzer Engineering Laboratories FCI monitors and GridSense TIQ transformer monitors were identified to demonstrate monitoring multiple endpoints on a single communications network. The locations spanned different types of enclosures:
    - o 3 Manholes
    - o 5 Underground Vaults
    - o 16 Handholes
    - o 44 Padmounts

  - Configuration of both the line-powered TIQs and the battery powered FCI monitors brought each utility an opportunity to better understand tailoring of reporting requirements to endpoint capabilities.

  - Selection of all hard-to-reach installation locations gave the utilities with planning data for all installation requirements in their territory.

As expected, the teams encountered installation challenges such as water in manholes and various critters inhabiting enclosures, but all endpoints were installed in a matter of weeks. The endpoints installed in padmounts took approximately 1 to 2 hours each, and those in vaults, handholes or manholes took approximately 3 to 4 hours each due to added traffic control and utility safety requirements for accessing the below ground locations. In addition to mounting the actual FCI or TIQ monitoring device, the corresponding antenna configuration was optimized for best fit for the location of the monitored endpoint and coverage characteristics of the enclosure.

Fig 3: Antenna diversity shown for a manhole endpoint installation

Once finished, the endpoints reported both status and alarm information:

- 30 Schweitzer Engineering Laboratories Underground 8301D Radio Rangers and 8301A Wireless Analog Interface Units reported underground FCI data every 6 to 24 hours and sent alarms based on configurable operating thresholds such as fault detection, current measurement, load statistics across twelve inputs (typically 4 circuits by 3 ways).

Fig 4: SEL Underground 8301A Faulted Circuit Indicator

Fig 5: GridSence TIQ Smart Transformer Monitor

- **Data Gathering and Analysis**: The On-Ramp Wireless project team monitored network and endpoint performance and generated weekly reports of data link quality throughout the 6 month period of the demonstration. Results were summarized in various DOE Deliverables provided throughout the project duration.

DOE Study Results

The project team successfully completed the DOE study, signifying a commercial wireless communications solution can be deployed by any utility working to address reliability of their underground grid:

- The wireless communications reliability of 99.8 percent of data packets received far surpassed other wireless communications technologies deployed underground asset monitoring.

- Network planning methodologies adapted for the challenges of covering static and hard-to-reach assets, such as those installed underground, proved highly accurate when validated against actual field measurements.

- The Schweitzer Engineering Laboratories and GridSense devices provided data that helped SDG&E and SCE predict reductions of underground line outage durations by an average of 90 minutes for a commercial deployment, lining them up to achieve the DOE 2015 and 2016 SAIDI reduction targets of 5 percent and 10 percent respectively.

- The On-Ramp Total Reach Network proved it could provide reliable monitoring coverage for underground assets located in vaults, manholes, hand holes, pad mounts, and other hard-to-reach locations cost effectively.

The Benefits of Monitoring Underground Assets

The benefits of automating below ground distribution grids is understood, and the On-Ramp Total Reach Network and partner monitoring solutions demonstrated an automation solution that fully positions utilities to meet DOE 2020 outage reduction goals. Additionally, the benefits of the solution extend beyond reduced outage time with additional information about power quality, load, voltage and other parameters. It showed that the On-Ramp Wireless solution enables utility companies to operate and manage electric distribution grids more efficiently, reduce energy use, pinpoint outage locations more quickly, and increase worker safety.

Currently, both utilities are actively evaluating additional monitoring opportunities like water level in underground vaults with the On-Ramp Total Reach Network. The rich data collected during the project contributed to the generation of the first network planning model designed specifically for statically deployed assets, applicable to designing both above ground and below ground monitoring solutions. Ultimately, the DOE-funded study achieved its objectives with the demonstration of a cost-effective commercial solution for monitoring underground grid assets.

All partners involved in the study are actively expanding the networks used for the demonstration, and working with other utility partners to evaluate use of the solution in their networks.

Additional References

The DOE project deliverables referenced for this discussion provide more detail about the study methodology, execution, and results:

- Smart Grid Automation for Underground Utility Assets, Wireless System Trade Study; prepared for U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, Smart Grid Research and Development; DOE-FOA-313; Contract DE-OE0000550; available now.

- DOE Program Final Report, Wireless System Analysis; prepared for U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, Smart Grid Research and Development; DOE-FOA-313; Contract DE-OE0000550; available April 2013.

About the author

Jason Wilson comes to On-Ramp Wireless with years of experience in product and program management in the telecommunications, defense electronics, and wireless industries. He earned a MS in Systems Management from the University of Southern California, and a BS in Astronautical Engineering from the United States Air Force Academy. Prior to joining On-Ramp Wireless, Jason was VP of Product Management at Ostendo Technologies, where he executed the development of an innovative immersive, curved screen display and secured a major DOD contract win for advanced imaging technologies. Before his time at Ostendo, Jason served in various product and program management roles at large companies and start-ups including L-3 Communications, TollBridge Technologies, and Nortel Networks. Early in his career, Jason served as an officer in the United States Air Force as a program manager for what are now the Delta IV and Atlas V launch vehicle systems.

Demand Response Takes Center Stage

By Jason Cigarran, vice president, corporate marketing and communications

Over the last 30 years, we have seen a historic rise in the demand for energy. In fact, since 1982, our nation's increased demand for electricity has outpaced the grid's transmission capacity by 25 percent annually. Understandably, this growing gap between electricity demand and capacity has placed a greater emphasis than ever before on tools that can help reduce peak demand.

One such tool is demand response. By managing peak demand, demand response has helped utilities and grid operators maintain grid reliability and stabilize electricity prices while also delivering a range of environmental benefits. In recognition of the important role it plays, FERC Order 745 mandated that demand response be compensated at the same rate as generation in organized energy markets.

Prior to FERC Order 745, the energy savings, or 'negawatts,' generated by demand response programs commanded less compensation than the megawatts created by energy producers. Now, when a net benefits test proves demand response is cost effective, demand response negawatts must also earn the locational marginal price (LMP) normally paid for megawatts.

The decision was a very important milestone for the demand response industry and demonstrates the critical role that demand side management programs play in our nation's energy mix. There are a lot of reasons why demand response has been so successful during the last 30 years, but three key areas help separate it from other forms of energy management.

Flexible Communication Models

Demand response systems offer a range of communication models to meet the varying needs of utilities and energy consumers.

One-way communication systems make up a large part of the demand response industry and play a critical role in managing the nation's power. They effectively shed excess loads during the summer cooling season and contribute needed kilowatts at other peak times.

For utilities with broader consumer engagement programs, demand response programs also offer advanced communication systems that engage customers in their energy consumption decisions. They enable demand response to offer solutions to more than just problems of load reduction. With these communication systems, demand response can deliver more advanced direct load control programs as well as dynamic pricing programs that deliver significant peak load reduction. Additionally, utilities can integrate these programs with conservation and energy efficiency programs that target base load reduction – an ever-increasing industry trend.

Personalized Programs

Another key factor behind the success of demand response programs is that they can be personalized to meet specific customer needs. This is necessary as different types of customers consume energy quite differently. For example, for residential customers in hot climates, HVAC draws the highest load. For industry, process loads predominate. As it turns out, an automated program structure works well for HVAC as load can be cycled so that the customer doesn't feel any or much impact, but process loads prove more complex and difficult to control remotely. Clearly, a one-size-fits-all approach is unlikely to deliver the highest levels of predictability and reliability, and instead utilities need to offer customized demand response programs.

The nature of customers' businesses or lifestyles will determine the demand response structure that will work best. A steel mill, for instance, will require a demand response system it can implement and manage without externally controlled operational interruptions. Energy use reductions must happen behind the scenes in ways that keep critical production elements in motion. On the other hand, a hospital will have different considerations, such as its emergency power generation capacity. A hospital will want to look at how it can leverage this emergency energy supply to benefit from participation in demand response programs. At times it may make sense cost-wise to use a back-up generator to replace some of the load carried by main power sources. Residential customers will look at ease-of-use and impact on comfort: will taking part in a demand response initiative burden their daily lives? The more simple and automated the demand response system, the more likely participation will seem enticing and prove worthwhile. Additionally, programs that use cycling technologies versus temperature offset provide benefits to both the consumer and the utility. From a utility perspective, cycling provides predictable demand reduction over multiple hours of control. For customers, the periodic cycling of the HVAC system improves comfort by moderating the rate of temperature rise and reducing humidity.

Utilities that understand the importance of customizing demand response and other energy management programs to meet different customer needs are seeing very impressive results. A perfect example is Pepco Holdings, Inc. (PHI), which is running one of the largest demand response programs in the nation. Its demand response efforts are part of a broader 'Energy Savings' program that offers a range of options to engage residential and business customers. Since it was introduced, the Energy Savings Program has reduced electricity consumption by more than 420,000 MWh.

Another lesson we've learned from marketing demand response programs to millions of residential customers is that it is difficult to predict exactly what consumers want. For example, in some programs, Comverge offers consumers a choice between a smart thermostat and a switch. Conventional wisdom says that customers would unanimously choose a modern, communicating, Web programmable thermostat over a switch that sits outside their house. But in reality, in programs that offer these two options, 65 percent choose the switch for reasons such as:

- They like their current thermostat
- They want to participate more passively in the program
- They simply don't want an installer in their house

The point is that by offering choice, demand response programs tend to have a high level of participation.

Depending on customer needs, successful demand response programs may incorporate a suite of different solutions. For example, PHI's program allows customers to choose between Web-programmable thermostats or outdoor switches as well as a variety of different cycling options. Program structure can also vary significantly based on the sophistication of the pricing options available to customers.

Compelling Compensation

Finally, and perhaps most importantly, demand response programs offer compensation structures that engage both residential consumers and commercial and industrial users.

Compensation structure can range from a set amount of money for a set number of hours of commitment to lowering energy use to dynamic rate structures and pricing schemes that give customers flexibility in how they choose to curb their energy consumption. This flexibility can lead to more customer participation and satisfaction because customers can determine which actions best suits their lifestyles and energy needs.

The early leaders in dynamic pricing automation – Gulf Power and Tampa Electric Company (TECO) – have demonstrated the profound impact such dynamic pricing schemes can have on demand response programs.

- Gulf Power has seen an 89 percent customer satisfaction rate with its TOU-CPP initiative, and nearly 87 percent of the time participants pay less for electricity. By adjusting price points between low, medium, high and critical
- TECO also delivers lower prices 87 percent of the time. It has reliably shed kilowatts during winter and summer peak every year since 2008 with its dynamic pricing program in place

Dynamic pricing also amplifies the importance of customer engagement in demand response programs. Because the infrastructure in effect gives customers the opportunity to save money, dynamic pricing changes the framework of demand response programs by incentivizing customers to increase their engagement with utilities. In so doing, it places an increased importance on the value and frequency of customer interactions.

A Reliable and Predictable Future

As the role of demand response continues to increase, system optimization will take center stage. Initiatives like dynamic pricing and other enhancements in customer engagement help tailor demand response to specific customers, ensuring it delivers the best possible performance across a broad spectrum of energy requirements. Automation that simplifies customer participation through set-and-forget capabilities will encourage more customer involvement. The more participants, the larger the positive influence demand response can have on the nation's energy distribution.

Demand response has proved invaluable throughout its 30 year lifespan and will continue to play a crucial role in moving the country to the smart grid. In addition to the integration of renewables, other clean energy initiatives actually threaten to strain the electric grid.

A valuable stabilizing force since its inception, demand response has the ability to be even more in the years ahead. It can – and will – in fact be revolutionary, endowing customers with more control than they have ever had before over their energy consumption and its price tag. In short, demand response will continue to enable utilities to meet the country's changing and growing energy needs, making the smart grid viable, and helping to keep the energy future secure.

About the author

Jason Cigarran is the vice president, corporate marketing and communications for Comverge. Prior to joining Comverge, Jason was the vice president, investor relations for Eclipsys Corporation, a healthcare information technology company. Prior to joining Eclipsys, he ran marketing programs for PCi Corporation, a division of Wolters Kluwer Financial Services. Mr. Cigarran has more than 19 years' marketing and communications experience in the information technology (IT) industry.

THE BIGGER PICTURE

BY BERNADETTE CORPUZ, BORDEN LADNER GERVAIS LLP

Ontario's Distribution Sector – Government Signals LDCs and their Shareholders Know Best

Approximately one year ago, the Ontario Government announced its plans to conduct a comprehensive review of the Province's electricity sector. As part of this review, the Government established the Ontario Distribution Sector Review Panel led by Murray Elston. The panel consulted with municipalities, local electric distribution companies ("LDCs") and the Electricity Distributors Association ("EDA"), as well as other energy experts to review potential savings associated with consolidation, benefits for ratepayers, operational efficiencies and potential risks. The review explored options to improve efficiencies, including local distribution sector ("LDC") consolidation. The panel recently delivered its report, *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First*, to the Minister of Energy.

The Panel's Mandate

The Panel's work involved a thorough review of the distribution sector, but Panel members kept their efforts focused on one key question: 'How can the province's LDCs deliver improved, cost-effective service to their customers while simultaneously supporting the future economic growth of Ontario?' In this statement rests the ever present objectives found in many a government's energy policies – cost efficiency and economic competitiveness and prosperity.

The Report

Despite the number of studies, reports, and past decentralization and consolidation efforts relating to Ontario's distribution sector, key participants in the electricity industry keenly awaited the panel's recommendations.

History

For anyone unfamiliar but curious about Ontario's distribution sector and how it came to be structured as it is (about 80 or so distributors almost all wholly owned by the municipality that it serves), the report provides a succinct, yet comprehensive historical account. The report reminds us that in the early 1920's, the Province saw almost 400 distribution utilities. Fast forward to the late 1990's and the number dwindles to about 90 following Ontario's passing of the Energy Competition Act. At this time, a number of municipal owners took advantage of temporary tax holidays which eliminated the significant tax that would have otherwise been levied on the proceeds of sale. But since then, consolidation has become the sometimes white elephant in policy discussions.

Current Backdrop

Universally it seems electricity distributors are being required to deliver more, not just in terms of the traditional performance benchmarks of reliability and safety, but in breadth. The report highlights Ontario's changing landscape with smart grid and homes, electric vehicles, distributed generation and changing customer relationships.

Often written about is Ontario's increase in renewable energy generation and the challenge it has posed for many LDCs in the province. Connecting the abundant Feed-In-Tariff (FIT) projects that have been coming online under the province's FIT program have sometimes caused issues for LDCs because of outmoded systems. This is critical to the distribution sector given the province's Long-Term Energy Plan forecast of an increase of approximately 9,000 megawatts (MW) in renewable power (excluding renewable power from hydroelectric) between 2010 and 2030.

In addition to the increase in renewable energy, a trend towards decentralization of the power supply is seen in the increased use of distributed generation that includes other 'close-to-load' technologies, such as combined heat and power and district energy.

In Ontario most residential homes currently have smart meters installed and most have made the switch to time-of-use (TOU) pricing. This aspect alone is resulting in a more informed, more engaged, and consequently, more demanding consumer. Front page discussions of electricity's cost to the consumer continue to be at the forefront even though Ontario is moving towards a smart grid at a time when much distribution equipment is aging and requires replacement or upgrading anyway. One might have expected a lesser degree of controversy over distribution investment but the debate on 'prudent' expenditures still ensues, from both regulatory and customer perception standpoints. Managing the balance between current costs and future effectiveness and prosperity continues to be a challenge for policy makers and the LDCs.

What the Panel Recommended

The report's description of the 'new world of electricity distribution' set the table for the panel's recommendations, all encapsulated in a new vision of distribution in the Province. The panel clearly stated its view that the sector's current structure is not equipped to meet the challenges that lie ahead stating that the LDC of the future must have a stronger balance sheet and capacity to adopt new technology so as to offer more advanced services in a cost-effective manner.

The panel was particularly focused on the number of electric distributors in Ontario, which hovers around 80. This number has been cited by at least some experts as too high to facilitate optimal efficiency and effectiveness in the sector but consolidation has been a highly controversial issue with the LDCs somewhat divided on positions. The report, however, did not waiver on this topic with its clear recommendation for a significantly restructured distribution sector in which the number of LDCs is shrunk to larger regional distributors. The panel's recommendations included:

1. The Province's LDCs be consolidated into 8 to 12 regional distributors that are large enough to deliver improved efficiency and enhanced customer focus, while at the same time maintaining a strong connection with their local communities.

   There should be two regional distributors to serve the north, one serving the northeast part of Ontario, and the other serving the northwest, leaving 6 to 10 regional distributors in southern Ontario. Any new regional distributor in southern Ontario should have a minimum of 400,000 customers.

   The new regional distributors must have boundaries that are contiguous and stand shoulder-to-shoulder. Boundaries should follow the existing structure and architecture of the distribution system, and take into account the existing Hydro One Networks service areas.

   No across-the-board sale of Hydro One Networks assets should be permitted. Rather, the system of regional distributors would be facilitated by the merger of Hydro One Networks' assets with those of existing distributors.

   Consolidation should be completed within two years of the Government's acceptance of the recommendations of this report.

The report included a number of related recommendations including:

a. the appointment of a transition advisor to oversee a consolidation process;
b. regulatory rate treatment of new entities that result from voluntary consolidation in the form of deemed net benefit to customers;
c. funds from the disposal of excess utility assets be re-invested in the regional distributors and not used for dividends or other non-electricity purposes;
d. savings from the increased efficiency of the new regional distributors would be shared between the shareholder and the customer; and
e. a board of a regional distributor should have at least two-thirds independent directors.

   In addition, an LDC's affiliates would not be included in consolidation and prohibitions on municipalities extending loans to LDCs in which they have an interest should be lifted.

The transition advisor would be mandated to provide status reports to the Government. The panel recommends that if the transition advisor's final report clearly indicates that the formation of regional distributors is not progressing, then the desired consolidation should be legislated.

The Government's Response

Ontario's distribution sector and stakeholders awaited the Government's response perhaps more eagerly than the panel's report itself. At the time of the report's release, it was well known that former Minister of Energy Chris Bentley and Premier Dalton McGuinty would be stepping down. Premier Kathleen Wynne coming into office heightened anticipation of the Government's response as all factions of Ontario's electricity industry watched for what policy direction her government would take.

At a recent address to the EDA, Ontario Minister of Energy, Bob Chiarelli, announced to the sector that he would not force local electricity distribution companies to merge. Instead, the government would seek local input on how best to create the climate and incentives to drive voluntary consolidation.

To date, however, the Ontario Government has not made any announcement as to whether it intends to implement any of the above recommendations. With a report expected soon from the Auditor-General of Ontario on the costs of power plant cancellations in the greater Toronto area and talks of a potential election, this may very well be the safest strategy for the Province's new premier and Energy minister for foreseeable future.

ABOUT THE AUTHOR

Bernadette Corpuz is a Senior Associate in the Electricity Markets Group of the law firm Borden Ladner Gervais LLP (BLG). As a member of the Electricity Markets Group, Bernadette advises a wide range of energy market participants, including distributors, transmitters, generators, and commercial users with respect to a variety of commercial and corporate transactions related matters, including mergers and acquisitions, financing and energy markets.

By Eric Byres

SECURITY SESSIONS

Using Zone Strategies to Secure Critical Infrastructure

> In recent years the number of cyberattacks directed at energy installations, including power utilities has increased dramatically. I discussed this in my article 'Securing Utilities from Cyberattacks - For the times they are a-changin' in the November/December 2012 issue of this magazine.

As a result, cyber security has become big business for the power industry. A recent report from research firm Zpryme estimates that between now and 2020 overall United States utility spending on cyber security will total $7.25 billion.

So what is the best way to defend your power infrastructure in this new era of escalated cyber threats? In this article I will explain how 'zones and conduits,' a concept included in ISA/IEC 62443 standards (formerly ANSI/ISA-99 standards), can help create a secure environment.

SCADA Security Challenges: Interconnectedness and Isolation

There are two opposing trends impacting substation control network design today.

The first trend is toward greater 'interconnectedness' of the entire grid. The ability for information to flow all the way from the smart meter at the customer's premises to the utility's management team is part of the attractiveness of modern networking technologies. Today, the information flow is largely one way, but we all know that one of the promises of the smart grid is to also feed data (and possibly controls) back down to the smart meter to improve the efficiency, reliability, and sustainability of the energy infrastructure.

The second trend is the desire to secure the grid by 'ring fencing' the bulk electrical system behind an 'electronic security perimeter' (ESP) as recommended by the North American Electric Reliability Corporation's (NERC) Critical Infrastructure Protection (CIP) program.

I am on the record as saying that I don't believe these bastion (single line of defense) models of security work today. What the Stuxnet worm showed us is that there are multiple pathways to sensitive equipment – pathways that don't require a connection to the Internet. You can read more about this in 'How Stuxnet Spreads.'

The reality of multiple pathways is also supported by work done by the U.S. Department of Homeland Security. They have stated:

"In... hundreds of vulnerability assessments in the private sector, in no case have we ever found the operations network, the SCADA system or energy management system separated from the enterprise network. On average, we see 11 direct connections between those networks. In some extreme cases, we have identified up to 250 connections..."

With the help of Murphy's Law, eventually all single point solutions are either bypassed or experience some sort of malfunction, leaving the system open to attack. A better solution is 'Defense in Depth' (DiD). In this model, the control system is protected by multiple layers of defense that are distributed throughout the control network.

This doesn't mean that boundary protection is not important – it certainly is. But this boundary protection must also be backed up by additional layers of defense.

Often it is easier and less expensive to secure a conduit than the assets at the end of it.

Defense in Depth is Key to SCADA Security

DiD is a best practice that is commonly used in the IT world. Rather than hiding the company behind a firewall, leading companies are starting to break their IT systems into defensible zones based on criticality. This white paper by Verizon on Network Segmentation and DiD describes the concept well:

> Traditional network security has been based on separating the enterprise internal network from all external connections and controlling what is allowed to enter. This plan cannot deliver effective security in today's enterprise networks. It is based on the assumption that all the "good guys" are inside the company and all the "bad guys" are outside. In practice, this assumption is never true. While bad guys sometimes manage to penetrate the castle defenses, most attacks are traced to the computers of insiders. Even with the best of intentions, any employee might be fooled by an e-mail, web page, or instant message containing a virus attachment—turning at least their computer, if not the employee, into a temporary bad guy.
>
> If a traditional 'perimeter defense' cannot protect today's enterprise, what can? Security-conscious enterprises are turning to fine-grained segmentation. This strategy, although focused on defense against cyberattacks, also pays dividends in terms of network flexibility and interactions with business partners. Segmented networks are orderly, carefully defined networks.

In the industrial SCADA world, this particular layered defense strategy is known as the zone and conduit network segmentation model. It is a core requirement of the in the ISA/IEC 62443 standards for Security for Industrial Automation and Control Systems.

ISA IEC 62443 Zones and Conduits

One layer of defense is to eliminate 'flat' networks and segment them according to the zone and conduit model that is included in ISA/IEC 62443. This model provides a way to segment and isolate the various subsystems in a control network.

A zone is defined as a grouping of logical or physical assets that share common security requirements, based on factors such as criticality and consequence. Equipment in a zone has a security level capability. If the capability level does not meet or exceed the requirement level, then extra security measures – such as implementing additional technology or policies – must be taken.

Any communication between zones must be via a defined conduit. Conduits control access to zones. Conduits also resist Denial of Service (DoS) attacks or the transfer of malware, shield other network systems, and protect the integrity and confidentiality of network traffic. Typically, the controls on a conduit mitigate the difference between a zone's security level capability and its security requirements, particularly when older, less secure components are still in service. Focusing on conduit mitigations is often more cost-effective than having to upgrade every device or computer in a zone.

The zone and conduit approach starts with defining groups of systems and assets that share common functionality and common security requirements. These groups are the zones that require protection.

For example, the first division might be operational areas, such as regions or substation types, with secondary functional layers defined, such as Supervisory Level, Station Level and Bay Level. Zones can also be defined according to an asset's inherent security capabilities. For example, older IEDs that have weak authentication (i.e., poorly designed password controls) could be grouped into a zone that provides them with additional defenses.

A conduit should then be defined in terms of:

- The zones it connects
- The communications technologies it uses
- The protocols it transports
- The security features it needs to provide to its connected zones

Typically, determining the information transfer requirements between zones over the network is straightforward. Tools like traffic flow analyzers or even simple protocol analyzers can show which systems are exchanging data and the services they are using.

It is also wise to look beyond the network, to determine the hidden traffic flows. For example, are files ever moved via USB drive? Do employees connect to outside resources using a dialup modem? These flows are easy to miss, but can result in serious security issues if not managed carefully.

Types of Conduit Controls

There are several options for implementing security technologies on a conduit, two of the most popular ones being industrial firewalls and virtual private networks.

Industrial firewalls control and monitor traffic to and from a zone, comparing the traffic passing through to a predefined security policy, and discarding messages that do not meet the policy's requirements.

Typically they are configured to allow only the minimum traffic required for correct system operation, blocking all other unnecessary traffic and filtering out high risk messages – such as programming commands or malformed messages that might be used by hackers.

These firewalls are designed to be very engineer-friendly and are capable of detailed inspection of SCADA protocols such as DNP-3, Ethernet/IP and Modbus/TCP.

Virtual Private Networks (VPNs) are networks that are layered onto a more general network, using specific protocols or methods to ensure 'private' transmission of data. VPN sessions tunnel across the transport network in an encrypted format, making them 'invisible' for all practical purposes.

Combining DiD and Zones and Conduits Strategies

DiD, that is multiple layers of defense distributed throughout the control network is one of the best ways to defend against today's cyber threats. Network segmentation using zones and conduits as defined by ISA IEC 62443 standards is an important element of a DiD strategy.

I strongly recommend you become proficient with segmenting your control networks for zones and conduits, and with appropriate industrial security solutions. Doing so will greatly assist your organization in mitigating threats from 'interconnectedness' and 'Son-of- Stuxnet' malware.

For a more detailed discussion about the zone and conduit model, download the White Paper "Using ANSI/ISA-99 Standards to Improve Control System Security" from the Tofino Security website. (http://web.tofinosecurity.com/download-the-white-paper-using-ansi-/-isa-99-standards-to-improve-control-system-security).

ABOUT THE AUTHOR

Eric Byres, P. Eng. and ISA Fellow, is recognized as one of the world's leading experts in the field of SCADA security. His technical knowledge combined with his background as a process controls engineer have been indispensable in his role as CTO and VP Engineering for Tofino Security a Belden brand. He has written extensively about the malware Stuxnet. Eric founded the British Columbia Institute of Technology (BCIT) Critical Infrastructure Security Centre and shaped it into one of North America's leading academic facilities in the area of SCADA cyber-security. For his efforts, Eric was awarded a SANS Institute Security Leadership Award in 2006. He is a notable contributor to industry standards and is Chair of the ISA99 Security Technologies Working Group and Chair of the ISA99 Cyber Threat Gap Analysis Task Group. Eric is Canadian representative for IEC TC65/WG13, a standards effort focussing on an international framework for the protection of process facilities from cyberattack.

Case Study: Using Zones and Conduits to Secure a Distributed Electronic Security Perimeter (ESP)

By Eric Byres

A large utility had an agreement with several industrial customers to buy and sell power. This required real-time communications between the utility substations and third-party facilities for power quality metering. The utility owned the metering equipment, but it sat in another company's premises, making the definition of an ESP fuzzy.

If inside the ESP, the demands for physical isolation and auditing were unrealistic. If outside, the traffic needed to be routed through the ESP firewall, adding complexity and risk. There was also the issue of how to manage any connectivity supported by third-party network elements.

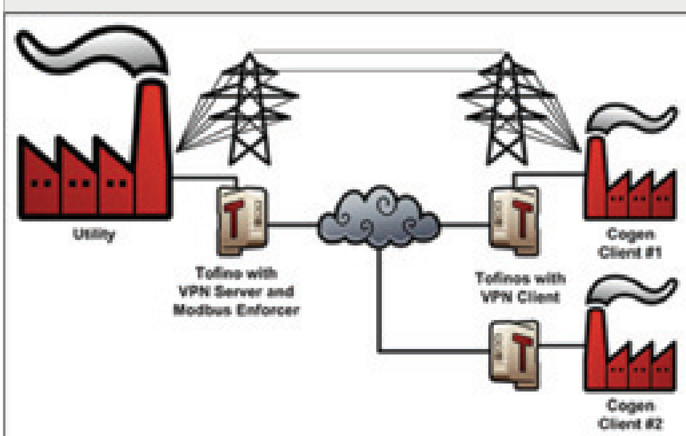
Fine-grained control of SCADA traffic between the customer and the utility could not be assured by standard IT firewalls; these can only deny the SCADA protocol in use and cannot filter it for specific content. This potentially allows dangerous functions, such as programming commands or malformed SCADA messages, to be injected from the client site into the utility's control systems as part of the permitted data stream.

The solution was to assume that the power meters were residing in a separate security zone that was outside of the utilities direct control. To provide adequate security, the conduits between the third parties' facilities and the utility needed three attributes: encryption of messages, authentication of the end points and fine-grained inspection, and filtering of all SCADA messages.

An industrial firewall was installed as a conduit at each end of the utility-to-customer-link. These firewalls were configured so that only read commands (and corresponding reply messages) were permitted over a VPN tunnel. The VPN tunnel also authenticated all connections and encrypted all traffic.

This solution ensured that only specific firewalls and associated control devices could connect to each other. All other attempts to connect to either the utility or client site would be blocked – as would any attempts to write data or send programming commands.

All traffic was encrypted, ensuring that messages could not be injected midstream. Finally, the security devices provided alerts for blocked SCADA messages or suspicious connection attempts.



Industrial Firewalls (Tofino Security Appliances and Loadable Software Modules) act as conduits to secure cogeneration facilities.

Guest Editorial >

Making the Smart Grid Smart Again

How to Overcome Inertia and Keep Your Utility on a Path to Adaptive Energy Conservation

By Max Park and Scott Zajkowski

Max Park

Scott Zajkowski

Dedicated Value

According to McKinsey & Company, smart grids are predicted to deliver $130 billion in value to utilities by 2019. This includes:

- $59 billion in customer applications
- $9 billion in advanced metering infrastructure
- $63 billion in grid applications; with $43 billion in volt-VAR value in particular[1]

The need to move to the smart grid is clear. Its value to utilities is predicted to reach US$130 billion annually by 2019.[2] But other research indicates that much of the potential of this market has yet to be tapped. An estimated total of 832 million smart meters will be deployed during the 2011-2020 timeframe.[3] This data implies that many utilities are not that far along the road to an advanced metering infrastructure. While it is expected that they will continue to move forward in the near future, what's the source of the holdup?

The fact is that many utilities want to move to the smart grid and have already made a significant investment in automatic meter reading (AMR). But there is confusion on where to go next. Some smart meters are in place and data id being been collected. But how does a utility translate that data into a strategic direction that will maximize the value they receive in cost savings, infrastructure improvements, and customer service – at the same time transforming into an adaptive organization that can meet the evolving energy demands of the future?

Take the High View

The problem is that utilities are getting caught in the weeds of meter deployment without taking a step back to develop a road map of their entire grid; where they are now and where they want to go. That's why they have no clear idea of what technology to deploy next. The answer to this challenge is distribution automation – the one technology that will provide utilities with the visibility they need to shape their smart grid as they move forward with a solid plan to meet their goals.

Distribution automation should be the primary focus of utilities from now until 2020. Why? Fault detection and fault isolation were considered separate issues in the past, but distribution automation takes a comprehensive view of these interrelated factors to enable volt/VAR optimization (VVO), fault isolation, system restoration and transformer monitoring – from large substations to even small or secondary transformers.

With this kind of asset management and analytics, a utility can move beyond simple monitoring. This is a predictive modeling solution that enables them to keep pace with their demand curve, maximizing their efficiency. They can conduct scenario modeling to really understand – and affect – what is happening with their grid at any given moment.

How to Keep Pace with a Fluctuating Workforce

Nearly 25-35% of the utility workforce is projected to retire in the period 2010-2015.[4] Distribution automation can help a utility maximize the performance of an aging workforce.

Distribution Automation Impacts Staffing

Distribution automation empowers a utility to make the most of their human resources as well. Most traditional utilities employ an annual maintenance schedule for their equipment, but with the enhanced monitoring capabilities of distribution automation, this type of schedule may no longer be necessary. A utility can now focus on the aspects of the grid that need it and apply resources in the most efficient and effective manner possible.

In terms of service interruptions, many utilities wait until consumer call volumes reach a certain level before dispatching a crew to look at a potential problem. Through distribution automation, a utility can more effectively monitor their feeder lines to pinpoint problems and know exactly where an outage has occurred. Through wireless SCADA, decision makers can receive an email or text notifying them of a problem to increase responsiveness. The outage is minimized reducing revenue loss and improving customer service as a result.

Voltage Control

Through volt/VAR control (VVC) utilizing distribution automation, utilities drop their output from 123-125 volts to 116-117 volts with no noticeable impact to the consumer. The result is that consumers will get longer life out of their appliances and they will be able to stop paying for unneeded voltage. While the utility may see negative revenue impact up front, as customer loyalty increases and new customers come online, revenue will ultimately increase. As customers increase, the need to build additional facilities lessens with VVC. That means increased revenue also translates into increased profitability.

Advancements in Transformers Support Distribution Automation

Recent technology developments do not stop with distribution automation. There is an entirely new generation of transformers designed to support the smart grid. Traditional transformers may only enable the monitoring of load and external temperature. To gain real insight into the status of a transformer's condition and performance, a utility needs to monitor:

- The status of the load; is it normal, abnormal, or dangerous?
- The internal temperature of the transformer; is it over-or under-loaded, or does it need to be replaced?
- Total combustible gas measurement to provide a parts-per-million aspect on what the real issues are with the transformer.

Through this kind of data, a utility can perform predictive maintenance as opposed to reactive maintenance. The key is to evaluate the monitoring technology of the vendor. Some solutions use external monitoring and cost $100,000 plus to monitor a single transformer. With an internal monitoring solution, the cost can be as low as $1,000 to monitor one transformer.

Defining the Bottom Line

The impact of VVC through distribution automation is lower operating costs, higher operational efficiency, less service interruption/less duration of interruptions resulting in higher customer satisfaction and higher revenue. In fact, a recent study concluded that the ability to operate a distribution system within tight voltage levels in the lower half of the acceptable range could yield a 1 to 3 percent total energy reduction, a 2 to 4 percent reduction in kW demand, and a 4 to 10 percent reduction in kVAR demand without any negative impact to the customer.[6]

Looking Ahead

Distribution automation can help utilities keep pace with the evolving demand of the future. There has been a dramatic rise in reactive loads in the last two decades and this demand is only increasing. For example, in the United States before the 1980s, reactive loads from electronic devices were insignificant. In 2010, the load from electronic devices has increased to 40 percent, and by 2015 it is expected to exceed 60 percent.[7]

Add to this stress on the system the development of electric cars. In 2012, approximately 50,000 plug-in electric vehicles (PEVs) were sold in the United States, and the market is expected to grow by more than 50 percent in 2013. When primarily charged at home, these vehicles can become the single largest power consumer of any device connected at a residence[8]. These vehicles are also unique in that they are typically sold in much greater concentrations in major population centers, magnifying demand spikes and their impact on power distribution equipment. With electric vehicles and distributed generation coming online, you need to have the right technology to make the right decisions at the edge of the grid. With distribution automation, you can get instantaneous information to energize your decision making process.

Benefits to Low Income Populations

Low income energy consumers are less aware of the smart grid than the general population but they still find its benefits appealing, according to a Smart Grid Consumer Collaborative (SGCC) research study.

"Every consumer, regardless of socioeconomic status, should be aware of the benefits of smart grid," said Patty Durand, SGCC Executive Director. "By educating low income consumers about these benefits and acknowledging their preferences, utilities have an opportunity to capitalize on untapped potential for demand reduction across the grid."[5]

The Smart Grid Goes Global

According to The Northeast Group:

"These 35 emerging market countries were active in deploying smart meters and associated smart grid infrastructure in 2012, with over 1.3 million AMI meters deployed. This activity does not even include the mega-markets of China and India, which are not covered in this forecast. A number of emerging market utilities have already announced large projects for 2013, fueling our expectations that the number of smart meter deployments will more than double next year."

All 35 countries analyzed in the study by Northeast Group are projected to begin smart grid deployments in the coming decade. In fact, 14 of the 35 countries are well positioned to begin large-scale smart grid deployments within the next 1 to 3 years.[9]

Acting globally

A recent analysis showed that the number of smart meter deployments across 35 emerging market countries in 2013 will be more than double the number of deployments in 2012. The global advanced metering infrastructure (AMI) market is projected to reach $56 billion by 2022.[10]

In the U.S. alone, estimates show that if the U.S. grid were just 5 percent more efficient, the energy savings and benefits to society would be equivalent to permanently eliminating the fuel and greenhouse gas emissions from 53 million cars.[11]

---

[1] Adrain Booth, Mike Green, and Humayun Tai, "U.S. Smart Grid Value at Stake: The $130 Billion Question," McKinsey & Company, (Summer 2010), http://www.mckinsey.com/client_service/electric_power_and_natural_gas/latest_thinking/mckinsey_on_smart_grid

[2] Adrain Booth, Mike Green, and Humayun Tai, "U.S. Smart Grid Value at Stake: The $130 Billion Question," McKinsey & Company, (Summer 2010), http://www.mckinsey.com/client_service/electric_power_and_natural_gas/latest_thinking/mckinsey_on_smart_grid

[3] "Smart Grid Technology Market To Total $494 Billion in Cumulative Revenue from 2012 to 2020," Pike Research, The Smart Grid Observer, (March 6, 2013), http://www.smartgridobserver.com/n3-6-13-1.htm

[4] David Mark, Ken Ostrowski, Humayun Tai, "Can the Smart Grid Live Up to its Expectations?" McKinsey & Company," (Summer 2010) http://www.mckinsey.com/client_service/electric_power_and_natural_gas/latest_thinking/mckinsey_on_smart_grid

[5] "Low Income Energy Consumers Weigh In On Smart Grid," The Smart Grid Consumer Collaborative, The Smart Grid Observer, (September 21, 2012), http://www.smartgridobserver.com/n9-21-12-1.htm

[6] "Improving Volt/VAR Control: Tighter Control Reduces Waste and Increases Grid Capacity," Echelon Corporation, The Smart Grid Observer, (2010) http://www.smartgridnews.com/artman/uploads/1/Volt_VAR_Solution.pdf

[7] "Improving Volt/VAR Control: Tighter Control Reduces Waste and Increases Grid Capacity," Echelon Corporation, The Smart Grid Observer, (2010) http://www.smartgridnews.com/artman/uploads/1/Volt_VAR_Solution.pdf

[8] "Best Practices for Utilities to Prepare for Electric Vehicles," Navigant Research, (2013), http://www.navigantresearch.com/research/best-practices-for-utilities-to-prepare-for-electric-vehicles

[9] "Emerging Markets To More Than Double Smart Meter Growth In 2013, $56bn Market By 2022," The Northeast Group, The Smart Grid Observer, (December 10, 2012), http://www.smartgridobserver.com/n12-10-12-1.htm

[10] "Emerging Markets To More Than Double Smart Meter Growth In 2013, $56bn Market By 2022," The Northeast Group, The Smart Grid Observer, (December 10, 2012), http://www.smartgridobserver.com/n12-10-12-1.htm

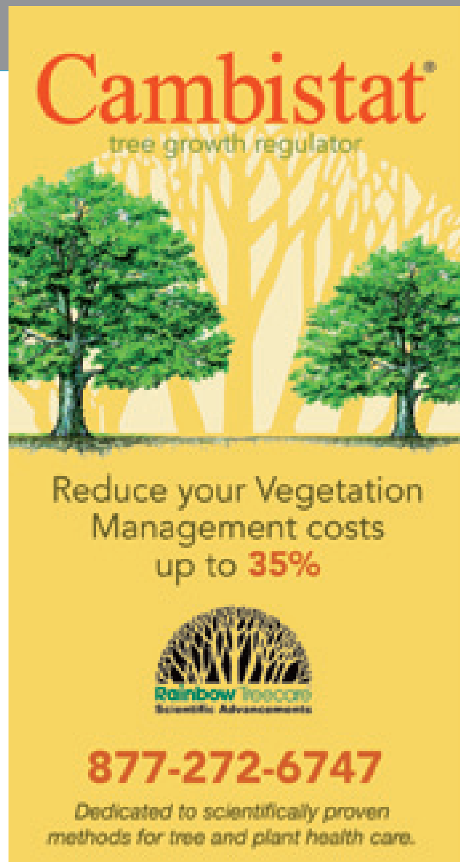
[11] "Improving Volt/VAR Control: Tighter Control Reduces Waste and Increases Grid Capacity," Echelon Corporation, The Smart Grid Observer, (2010) http://www.smartgridnews.com/artman/uploads/1/Volt_VAR_Solution.pdf

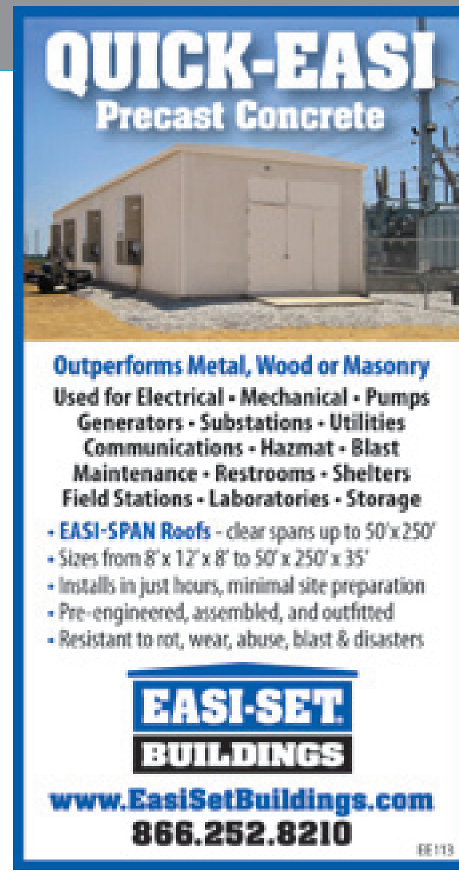
ABOUT THE AUTHORS

Manufacture Engineer Manager, **Max Park** is a member of the Vitzro and its subsidiary IUS Technologies team since 2002, Max has concentrated his career on the design and development of grid operational equipment and Smart Grid distribution automation. During his career Max has also worked with LS Industrial System and Hyosusng. He is a focused technical specialist with expertise in the research and development of high and low voltage devices. Max graduated from Myongji University, and received a Masters from Busan National University in Mechanical Engineering; he specializes in design and product development, equipment testing and is a certified project manager.

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

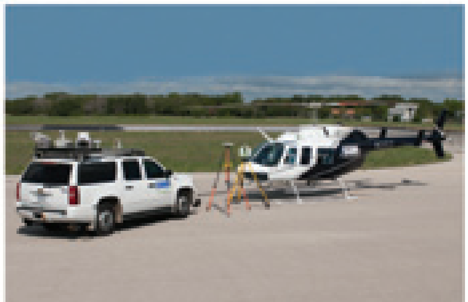
PRODUCT SHOWCASE



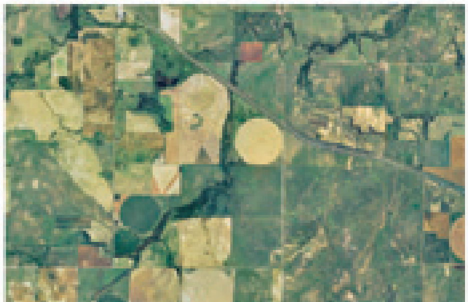


ADVERTISERS INDEX

COMPANY	WEB SITE	PAGE #
Bronto Skylift	www.bronto.fi	33
Brooks Utility Products Group	www.brooksutility.com	15
California Turbo, Inc.	www.californiaturbo.com	22
CTC Global Corporation	www.ctccable.com	47
Doble Engineering Co.	www.doble.com	3
EASI-SET Worldwide	www.easiset.com	48
GarrettCom Inc.	www.GarrettCom.com	12
Hastings Fibeglass Products Inc.	www.hfgp.com	11-48
Incon Power Reliability Products	www.incon.com	18
Inner-Tite Corp.	www.inner-tite.com	14
Novatech, LLC	www.novatechweb.com	1
Optisense Networks LLC	www.optisense.net	30
Open Systems International, Inc.	www.osii.com	Back Cover
Prolec GE International, S DE R.L. C.V.	www.prolecge.com	Inside Front Cover
Rainbow Treecare Scientific Advancements	www.treecarescience.com	48
RuggedCom Inc.	www.ruggedcom.com	13
Surveying and Mapping Inc. (Sam, Inc)	www.saminc.biz	Inside Back Cover
S C Electric Company	www.sandc.com	7
Schweitzer Engineering Laboratories Inc.	www.selinc.com	9
Systems With Intelligence Inc.	www.SystemsWithIntelleigence.com	5
Tech Products Inc.	www.techproducts.com	48
TSTM	www.ts-tm.com	25
Underground Devices Inc.	www.udevices.com	23



Airborne, Mobile & Terrestrial LiDAR



Aerial Mapping & GIS

Professional Land Surveying


Smart grid projects can be deceiving.
The ultimate Smart Grid vision portrayed by many still remains nothing but a panacea. If you are interested in a practical, pragmatic vision of the Smart Grid and need your vision successfully realized, make us your partner. If you want results instead of reports or marketing campaigns and want a Smart Grid strategy which is sustainable both post implementation and year after year, make us your partner. We'll help you plan and execute a realistic yet sensible vision of your Smart Grid strategy beyond smart meters and data warehouses, articles, press releases, commercials, speeches and odd partnerships.
Join the large number of utilities who, with our help, are quietly and solidly realizing their true Smart Grid vision.
OSI
We'll get your project down to size.
osii.com
© 2013 Open Systems International, Inc. All rights reserved.