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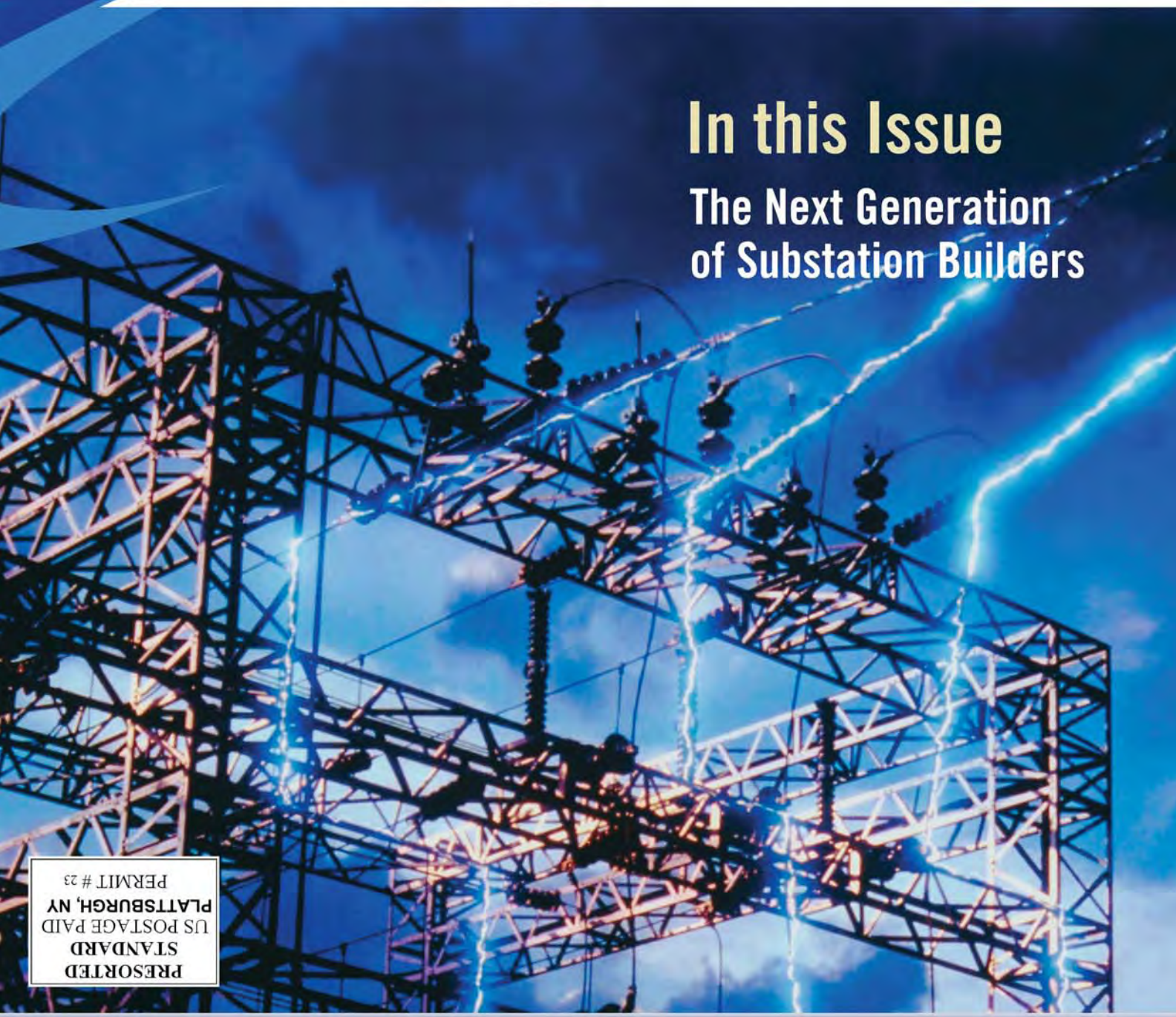
Electric Energy T&D MAGAZINE

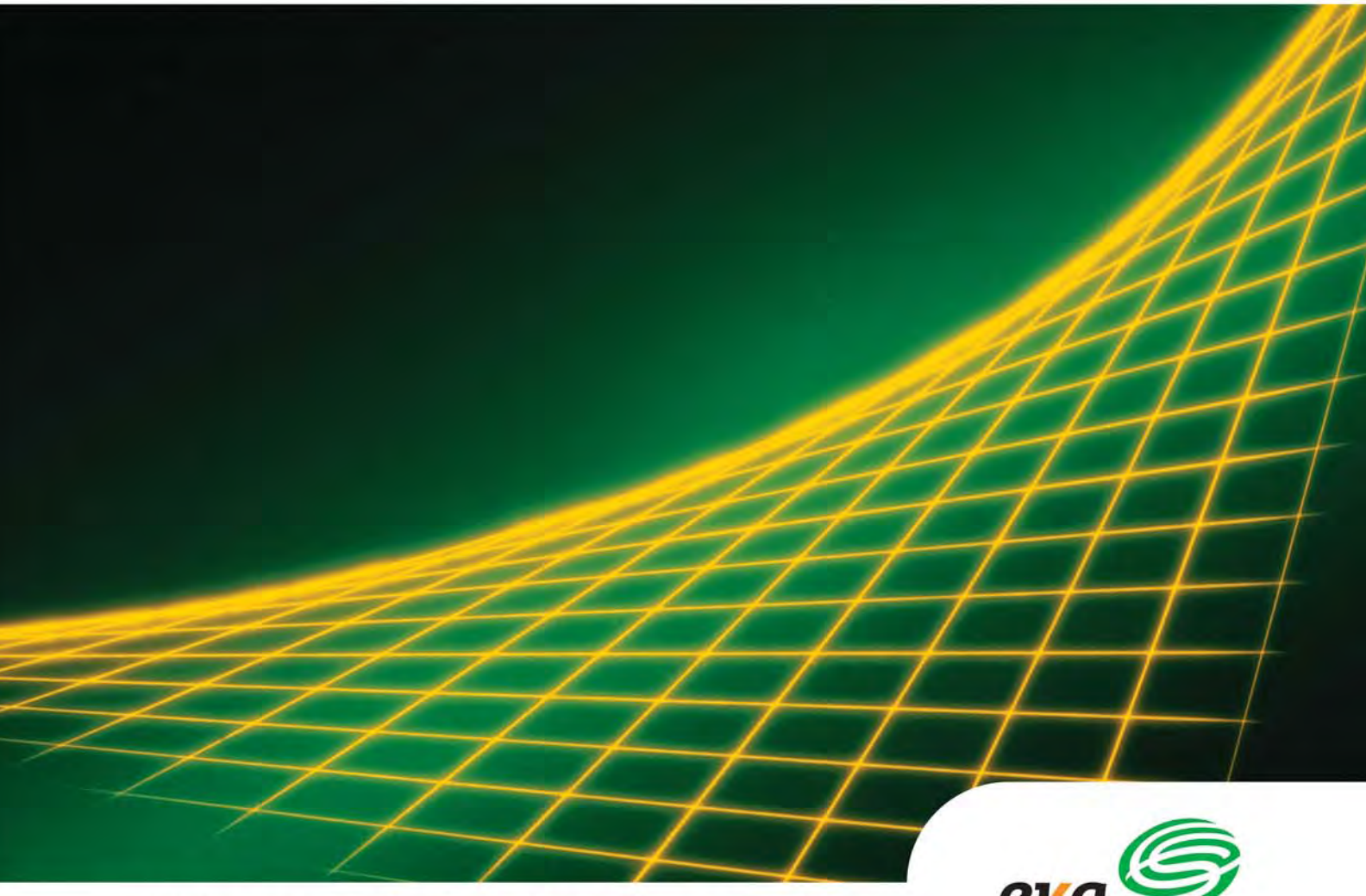
JANUARY-FEBRUARY 2007 Issue 1 • Volume 11



In this Issue

The Next Generation of Substation Builders

NOTHING ELSE MEASURES UP



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Publisher:
Steven Desrochers: steven@electricenergyonline.com
Editor:
Gordon McCormick: gordon@jaguar-media.com
Contributing Editors:
Mike Marullo: mam@electricenergyonline.com
Account Executives:
Jimmy Desjardins: jimmy@electricenergyonline.com
Steven Desrochers: steven@electricenergyonline.com
Circulation Manager:
Janet Guay: janet@jaguar-media.com
Art Designers:
Frederic Allard: fred@jaguar-media.com
Anick Langlois: alanglois@jaguar-media.com
(MIS) Management Information System:
Frederic Allard: fred@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
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"CCAB/BPA WORLDWIDE MEMBERSHIP APPLIED FOR DECEMBER 2005"

COVER PAGE PHOTO: **www.photo.com**

Electric Energy T&D MAGAZINE

IN THIS ISSUE

Solving peak issues through demand response…

Austin Energy is giving away free programmable thermostats that are keeping customers comfortable – and cutting Austin's summer peaks.

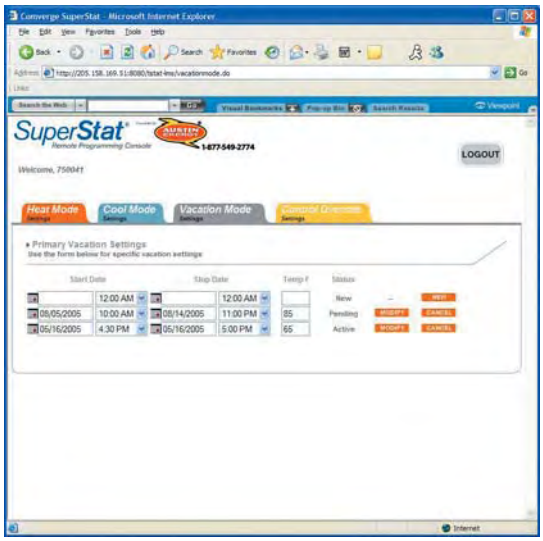
In addition to the Energy Star rating that helps customers save up to 15% on their heating and cooling bills, these thermostats have an embedded communications chip that enables Austin to remotely cycle back air conditioning usage on peak days. With over 50,000 participants, the Power Partner program contributes an average of 45 megawatts of peak capacity to Austin's overall supply portfolio.

Alongside the thermostat, the program features a web programming tool which allows participants to program their thermostat over the web – from anywhere with an internet connection.

Austin Energy's Power Partner Program gives participants a free Demand Response enabled programmable thermostat

Austin had faced rising peaks as central air conditioning became more and more prevalent in the Austin area. In order to solve peak capacity challenges without building a plant or purchasing power off the spot market, Austin developed a portfolio approach of energy efficiency, demand response, and overall conservation programs.

"The portfolio approach, including a broad range of strategic conservation, load shifting, and peak clipping resources, made sense for us," said Steve Saenz, Program Coordinator of Austin's DSM Energy Services Unit. "The programs provide real value to our participants while at the same time allowing us to cut peak procurement costs and keep electricity prices low for everyone."



Austin Energy's Power Partner Web Portal allows participants to program their thermostat online – anytime, anywhere!

The Choices

As Austin evaluated options for the Power Partner program, answers to technology, communications, and implementation choices were not immediately obvious. The team at Austin conducted in-depth research and analysis of virtually every major vendor in the space, coupled with interviews with other utilities currently implementing load management programs.

Of the many issues that the team evaluated, they spent the most time considering one way vs. two way communications, VHF (lower frequency) vs. 900 MHz (higher frequency) paging, and determining the right mix of control switch and "smart" thermostats for their service territory. "At this stage of our program, we were looking for the most cost-effective solution that would meet our needs and stay within our budget," commented Saenz.

Two-way communicating thermostats can provide utilities with more data on their load management system, such as verification of receipt of signal, temperature data, and overall usage trends. They also enable real time and critical peak pricing rate options when coupled with an AMI system by verifying the receipt of a critical pricing signal. The drawback on this technology, however, is cost of the return communications path. From a design perspective, the additional power required to generate a return signal requires costly technology – think of it as virtually integrating a cell phone into every thermostat. Even though cellular technology would not be used in this application, it's an easy way to envision what a two-way communications module might require. This can translate into a cost of over double that of a one-way solution – which, when identically configured, provides the same load shed capacity as its two-way counterpart.

"While a two-way communicating thermostat provided lots of intriguing bells and whistles, the end result in terms of megawatts was no different than that which could be achieved with a one-way stat," said Saenz. "The cost adder on the two-way device coupled with high recurring communications costs lead us away from a two-way system and encouraged us to look at different methods of system measurement and verification such as physical inspections and statistical sampling."

Higher vs. lower frequency paging can make all the difference in a load management program as signal strength and penetration determine whether an end device receives the utility's signal to control. For a load management system – especially thermostat based, where the receiver is

static and indoors – VHF (lower frequency) has proven to provide markedly better reception than 900 MHz (higher frequency) due to its heightened ability to penetrate buildings and walls. Higher frequencies are often stronger for mobile endpoints – like a police car, for example - as these signals are more inclined to reflect off of objects and therefore provide more seamless coverage.

"In the end, we chose to utilize our existing and operable VHF communications infrastructure - a technology that met our needs at the lowest possible cost – and chose a one-way, VHF communicating "smart" thermostat provided by Comverge," said Saenz. "Their product – especially the second generation device that we're presently installing – has met all of our requirements and helped us to stay within our budget. In Comverge, we've also chosen a partner who has been as committed to the success of our program as we have."

"Throughout the 2005 testing and deployment of the second generation thermostat, the teamwork and communication between both teams enabled a more robust and ultimately more successful product to be developed – from hardware to firmware to system communications to the web interface," commented Howard Ng, SuperStat Product Manager at Comverge. "When an opportunity arises to make design changes up front that will eventually make a client's program all the more successful, we are very happy to do that."

The second generation "smart" thermostat, jointly designed by Comverge and White-Rodgers/Emerson, is based on the most popular thermostat platform in the United States. Featuring a large, backlit display (key to usability – especially if mounted in a dark hallway), the "SuperStat" is attractive, easy-to-install, and compatible with most HVAC systems (including heat pumps and emergency resistance heating). The SuperStat has received accolades at many of the industry's premier conferences as the leading "smart" thermostat available on the market today and continues to be the focus of interest for utilities and consumers alike.

"We initially launched the program as a pilot of 3,000 residential points, but within six months we had ramped up to 10,000 points and began to broadly market the program," said Saenz. The program currently has over 21,000 single family residential participants; 25,000 multi-family participants; and over 4,000 small commercial participants.

The program offers no cash or rebate incentives to participants when they sign up – only the SuperStat, which is a difference from many of the nation's demand response programs which often offer rebates of up to $100 to sign up. Participants receive the free SuperStat in exchange for allowing their A/C to be cycled back on weekdays from 4:00 pm – 8:00 pm during the summer months (June – September). The program is never run on a holiday or weekend, which means that many participants will never even be home during an "event."

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Elster consists of two major business units in North America: Elster Gas and Elster Electricity and Water. Elster Gas delivers gas metering solutions to a host of customers across the region and is headquartered in Madison, Ohio. The Elster Electricity and Water business unit serves utilities in these two sectors with operations located in Raleigh, North Carolina and Ocala, Florida. Elster Integrated Solutions, a business based in Raleigh, North Carolina, helps utilities improve their revenue cycle services, customer service, delivery reliability and workforce utilization as well as implement demand response and conservation programs.

"We deliver and integrate metering automation solutions for our customers so that they can better manage their business in the area of gas, electricity and water usage as well as facilitate new end-customer programs. Whether it is automated meter reading (AMR) or advanced metering infrastructure (AMI), we enable business and customer management from the metering information. Core to our solution is the use of intelligent mobile and fixed network communications."

Sharon S. Allan, President, Elster Integrated Solutions

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Austin uses a 33% cycling strategy with an Adaptive Algorithm, intelligence that customizes the cycling time to each individual compressor, thereby eliminating free-riders. As compressors can be oversized or undersized for the amount of space they cool, their run times vary considerably – from an oversized compressor that hardly runs at all to an undersized compressor that runs constantly. Without an Adaptive Algorithm, a 33% cycling strategy would ask each of these compressors to turn off for 10 of 30 minutes which may not affect the oversized unit at all, while considerably affecting undersized unit.

The Adaptive Algorithm records the compressors run time on an hour by hour basis, so that the compressor will be cycled back 33% from its run time of the previous hour when an event is called. For example, if a compressor ran 15 minutes on and 15 minutes off over the past hour, the usage would change to 12 minutes on and 18 minutes off during an event. This allows for equitable cycling across the population and provides greater load shed and higher comfort levels for participants. Data from across the country has shown that this translates into an average indoor temperature change of 1-3 degrees over an event – unnoticeable by many people.

Austin's customer survey response data is evidence of the program's non-intrusive design. Even with 12 events in 2005 and 13 in 2006, all survey respondents said that they would recommend the program to another person, with over 80% responding "Definitely." Over 3/4 of respondents identified their experience with the program as "Excellent."

"We've found the technology and model that works for us, and is obviously working for our participants," commented Saenz. "And we're working every day to make it even better."

For more information, on Austin Energy's Power, contact Steve Saenz, Program Manager, Austin Energy & Arthur Vos, VP, Products, Marketing, & Strategy, Comverge www.comverge.com

Circle **183** on Reader Service

GESTALT LAUNCHES AUTOMATED METER/METER DATA MANAGEMENT PRACTICE

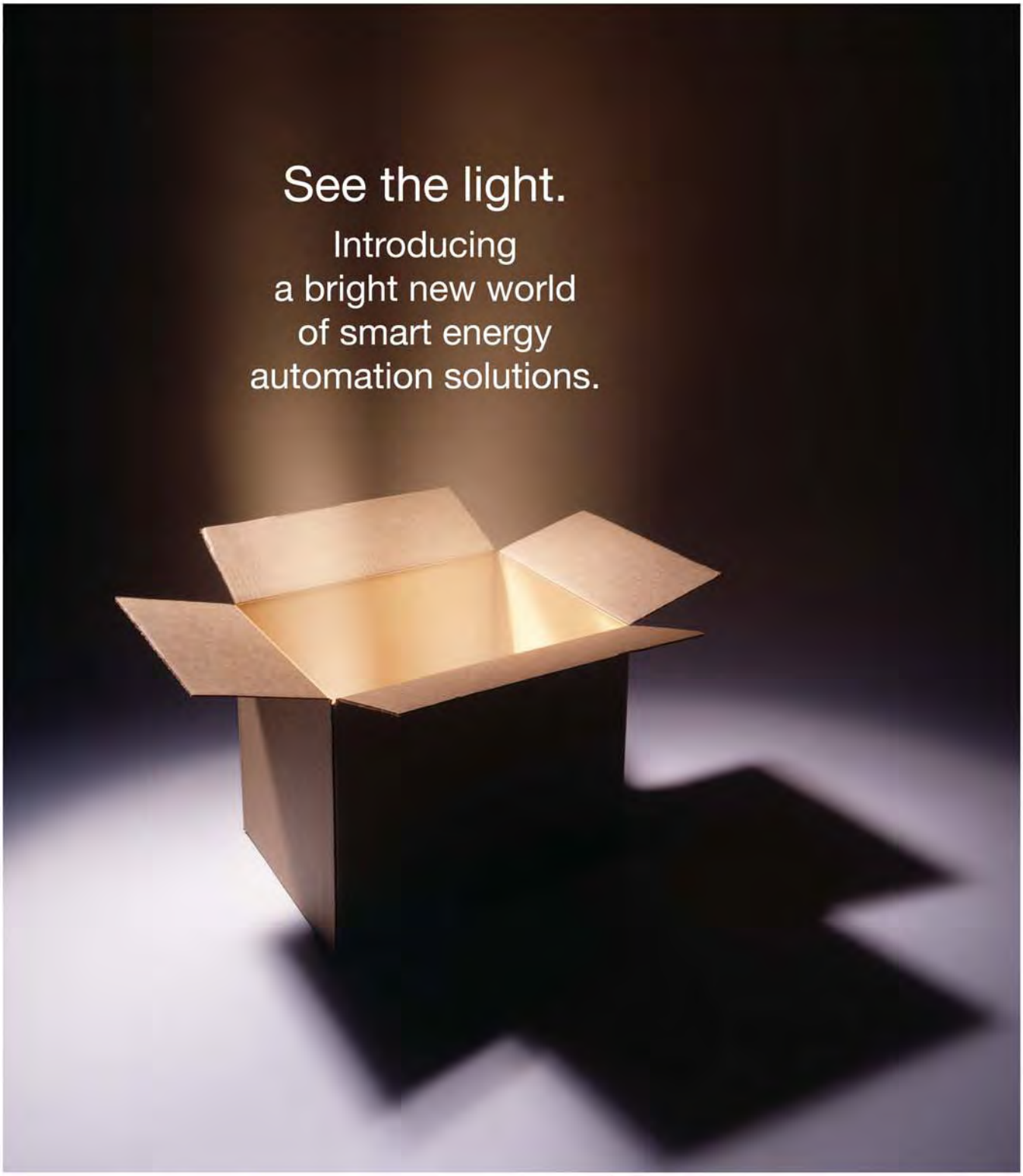
Top Experts Come Together to Serve One of Industry's Fastest Growing Sectors

Gestalt, LLC, an international professional services firm providing consulting services and technology solutions to the energy and utility and defense sectors today announced the formation of its Enterprise Technologies group that will deliver consulting and integration services for projects in the distribution automation, automated metering, and meter data management space. The move is in response to the growing demand for expertise in this area as both regulators and utilities across the nation push for continued adoption of these technologies as a means of increasing energy conservation and operational efficiency.

"The real value of technologies such as AMI is not simply in the meters themselves, it comes from how the data from these systems is leveraged within the organization," said Mark Rossi, Gestalt's Executive Vice-President, Energy & Utilities. "We're working closely with our clients to identify and implement practical solutions that leverage these technologies for areas such as demand side management, time-of-use billing and operational event tracking systems."

Most recently, Gestalt's team has successfully integrated a meter data management system into a utility's CIS system and translated the time-of-use meter data into customer-facing utility bills.

Leading this new team are two seasoned industry executives, Gary Murphy and Eric Smith. Gary Murphy, who has been Gestalt's chief practitioner in AMI and Smart Grid consulting engagements, has enhanced Gestalt's reputation as a thought leader in the North American energy and utility market. He has over 25 years of progressive leadership experience in generation and transmission and distribution utility operations, with an in-depth understanding of the business drivers of today's utilities. Murphy also leverages his experience in utility business process, organizational design, and technology solution implementations to help organizations achieve breakthrough levels of financial and operational performance.



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Eric Smith has held key positions with leading AMI vendors including Elster Metering, FieldTech, Invensys IMServ and Silver Spring Networks. He is a recognized authority on Distribution Automation Technologies. He has been integral in their evolution for more than 20 years, including the development of one of the earliest multi-AMI vendor software platforms. Smith has worked with numerous distribution utilities in all areas of AMI from business case development and technology selection to deployment strategies and implementation.

Circle **184** on Reader Service

NEOPTIX FIBER OPTIC SENSORS INC. NOW COVERS ITS TRANSFORMER HOT-SPOT FIBER OPTIC MONITORING SYSTEMS FOR 5 YEARS

Neoptix Fiber Optic Sensors, Inc., a company specialized in fiber optic temperature sensors, announces its new 5-year warranty coverage on all of its optical systems for transformer hot-spot temperature monitoring.

Neoptix, a leader in temperature sensing solutions for large transformer hot-spot monitoring using fiber optic technology, announces that as of December 15, 2006, all of its systems designed for permanent transformer monitoring will be covered by a complete 5-year warranty.

The 5-year warranty protects the Neoptix T/Guard and T/Guard+ systems and covers parts and service costs for the signal conditioner for the totality of that period. Moreover, our 48-hours product turn-around policy is still attached to the products. The warranty also covers all consumable parts including the PCB batteries and the light source, even if this source is rated for more than 50 years of use.

"This warranty extension is a direct result of the quality and the confidence we have in our products. We are designing and manufacturing with the long term in mind by selecting the most robust components on the market. Our instruments' track record on the field allows us to extend the warranty with assurance," says Mr. JF Meilleur, President of Neoptix. "Since our products are compliant with all GaAs based products, many customers have decided to replace their old and unreliable signal conditioners with Neoptix' proven systems. The 5-year warranty is an additional incentive in that direction."

The 5-year warranty is attached to the system and is automatically transferred to the end-user and is transferable at no cost.

The 5-year warranty is included free of charge and applies to all systems shipped from Neoptix starting December 15, 2006.

For more information about Neoptix products, visit the company's web site at www.neoptix.com.

Circle **185** on Reader Service

JEA AWARDS OSI A CONTRACT TO SUPPLY ITS NEXT-GENERATION ENERGY MANAGEMENT SYSTEM

(Minneapolis, MN) Open Systems International, Inc. (OSI) has been awarded a major contract by JEA of Jacksonville, Florida to be the supplier of its next-generation Energy Management System (EMS) technology.

JEA's electric operations currently serve more than 360,000 customers in Jacksonville and parts of three adjacent counties. JEA's main motivation for this project has been the implementation of a more modern and secure operations control system based on an open architecture, facilitating future upgrades of hardware and software as well as a lower recurring maintenance cost. The new system replaces a current system supplied by General Electric (GE).

The proposed system is based on OSI's monarch™ distributed open architecture and includes Supervisory Control and Data Acquisition, Automatic Generation Control and Dispatch (AGC), Historical Information System, Transmission Network Analysis, Web-based Graphical User Interface, Operator Training Simulator and Secure ICCP communications, as well as capability for a hot standby backup/disaster recovery control system.

"We are very excited about adding JEA to our expanding user base. JEA's decision to choose OSI for this important project is again a continued affirmation of our technology, superior customer service and our focused commitment to the utility marketplace. We look forward to a very successful project and a long term partnership with JEA," said Bahman Hoveida, President & CEO of OSI.

OSI (www.osii.com) provides open, state-of-the-art, and high-performance automation solutions to utilities worldwide. These solutions include Supervisory Control and Data Acquisition (SCADA) Systems, Network Management Systems (NMS), Energy Management Systems (EMS), Distribution Management Systems (DMS) and Generation Management Systems (GMS), as well as individual software and hardware products and e-business solutions for utility operations. OSI is headquartered in Minneapolis, Minnesota, USA.

JEA (www.jea.com) is the eighth largest community owned electric utility in the United States, providing electric, water and sewer service to more than 875,000 accounts in northeast Florida.

For additional information regarding this news release please contact news@osii.com.

Circle **186** on Reader Service

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We Have Answers.™

By Michael A. Marullo, Contributing Editor

A fine 'Messe'

Just about ten years ago I wrote an editorial (for another publication) about utility automation conference timing and venues. The gist of the message was the (apparently) radical notion that conferences, trade shows and symposia produced by various professional associations, conference developers and trade groups should consider meeting on common ground. That is, why not consider 'co-locating' (i.e., at a common time and location) these events instead of holding them at different times and different locations every year?

As we all know, for many years there has been a rising tide of complaints by exhibitors and attendees alike about the growing preponderance of events that routinely overlap or otherwise conflict while placing what can be an excruciating strain on time, resources and budgets for all concerned. Indeed, some events are scheduled so close to others that deciding whether to attend and/or exhibit at one or the other is often determined purely by logistics rather than the value of the events themselves. And, having to make new plans from scratch for multiple events every year is both difficult and time consuming – not to mention costly.

After writing that column, I personally followed up with a half dozen conference organizers to see if I could turn the concept into reality. But while most of them listened politely to my co-location concepts and nodded at all the appropriate junctures – indicating that they understood what I was saying – I soon realized that all I was getting was lip service. After much reflection on those conversations, I came to realize that I hadn't really gotten to first base with any of them.

In trying to put my finger on the reason why my charm and persuasive skills were failing me so miserably, I eventually realized that the fundamental problem was what I have since labeled, Organizational Ego.

Organizational Ego is a form of "group think" that sometimes develops within professional associations, trade groups and similar organizations that are governed by a common set of rules, regulations, guidelines and standards. These organizational constitutions serve not only to bind members to the organization, but also tend to foment a strong sense of organizational self. Yet despite the positive aspects of this self-awareness – and there are many – eventually and inevitably, self-awareness gives way to self-righteousness.

Before I take this any further, let me be clear that it is not my intention to portray 'ego' as a dirty word. On the contrary, a healthy ego is an essential ingredient in the success of most (if not all) highly motivated leaders and entrepreneurs. However, when an ego develops in an organization, no one takes ownership or responsibility for controlling it. Instead, organizations start thinking of themselves almost as a monolithic body, often without reassessing its value, currency, relevancy or general viability at any given point in time.

Fast forward to 2007: During the past several years, many of these organizations have found themselves drifting away from their original vision/mission and increasingly at odds with their own members and stakeholders. Why? There are a multitude of reasons, but most are rooted in the failure to change with the times. And, the organizational ego – often developed and nurtured over years or even decades – inherently resists change, often in direct opposition to what constituents are saying they want. If this seems like a weird and convoluted notion, perhaps it is; but I've seen it happen in several of the organizations to which I myself belong, so I know it's real.

That said, let's get back to the co-location concept. Clearly, a lot has happened since entering the twenty-first century that we can't afford to ignore: Indeed, the 9-11 attacks, corporate scandals, 2003 Northeast Blackout, ubiquitous Internet and pervasive wireless communications have individually and collectively changed even the most basic rudiments of how we conduct business. When it comes to conferences, trade shows and the like, almost everything has changed there as well. Gone are the days of going to conferences to get away for a few days at a luxurious resort destination; today, it's all about educational content, tangible results and above all – controlling costs.

By Michael A. Marullo, Contributing Editor

At the same time, the vast information resources of the Internet have caused many to attend these events for very different reasons than they once did – or in many cases, not at all. Indeed, travel logistics in a post 9-11 world are far more complicated and enormously more expensive than in the earlier tranquility we all enjoyed previously. Moreover, the allocations of time and money to specific tasks have been subjected to unprecedented levels of scrutiny, especially as the human resources needed to carry out those tasks rapidly diminish.

I don't think I even need to get into the security frustrations of trying to get even a laptop from one city to another, let alone crates of electronics, sample instruments or entire systems. And, you can pretty much forget about carrying on any lubricants, solvents or even a can of compressed air for cleaning out your keyboard. Now, multiply that by a few thousand people, a few hundred companies and a half-dozen or so events each year, and the result is some very expensive chaos. We've grudgingly come to accept these annoyances, but I just can't believe that there isn't a less painful way to do this without inadvertently killing the whole concept of these vitally important industry events.

Let me be clear that I'm not suggesting any organization should merge their event into that of another organization, thus, constituting absolute heresy to the organizational egos of both entities. But why not consider a slightly different approach whereby multiple events are simply co-located? That way, neither organization needs to relinquish its identity or its constituency and all can preserve the bulk of their organizational and financial independence.

As you might have guessed by now, this is not a lark nor (unfortunately) is it an original idea. The concept is squarely based on the world-renowned Hannover Messe (messe being the German word for fair – as in trade fair) held in Germany where they have been doing it that way for over 60 years. When the 2007 event convenes in on April 16-20, it will incorporate over a dozen individual conferences, each of which with its own identity and member/attendee following. The scope of topics ranges from energy to micro-technology with broad focus on technical innovation and creative application of existing knowledge, as depicted in the following event profile as posted on their website: http://www.hannovermesse.de.

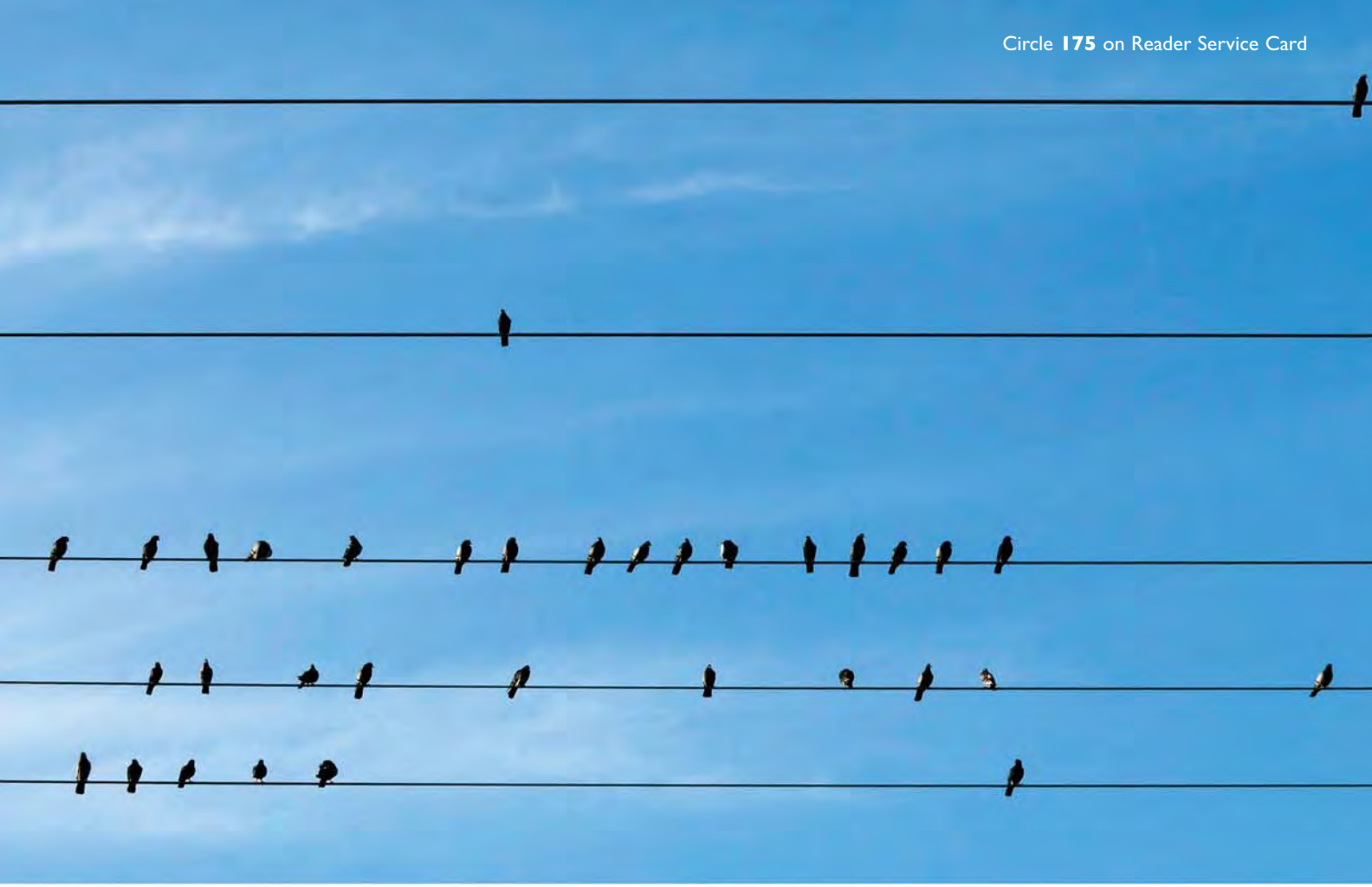
"HANNOVER MESSE remains the world's leading showcase for industrial technology. Better, faster, more effective: to survive and prosper in the face of global competition companies need to constantly maintain and improve their performance potential. Leading-edge technology plays a pivotal role in corporate competitiveness. HANNOVER MESSE is the ideal place to obtain the latest industrial know-how. Established almost sixty years ago, the Hannover Fair today ranks as the leading international showplace for industrial technologies, materials and product ideas. Over the years the focus has shifted from stand-alone components to end-to-end solutions. Technical innovation is one key element in the success of HANNOVER MESSE. Another is its sharp focus on the creative application of existing knowledge. Only at Hannover can the visitor experience complete value chains and swap information with experts from a complete spectrum of industrial sectors."

I'm sorry, but with all due respect to the many fine trade and professional organizations out there, someone will have to explain to me how following the Hannover model could possibly be a bad idea. (In my mind, sixty years of success speaks volumes.) The time has come for conference organizations – along with their owners, managers, members and attendees alike – to take stock of their futures and consider alternatives to the downward spiral that many have experienced over the past several years. I can't help but wonder who will be first to take the bold step toward creating the kind of messe we can all be proud of.

- Mike ■

Behind the Byline

Mike Marullo has been active in the automation, controls and instrumentation field for more than 35 years and is a widely published author of numerous technical articles, industry directories and market research reports. An independent consultant since 1984, he is President and Director of Research & Consulting for InfoNetrix LLC, a New Orleans-based market intelligence firm focused on Utility Automation and IT markets. Inquiries or comments about this column may be directed to Mike at MAM@InfoNetrix.com.



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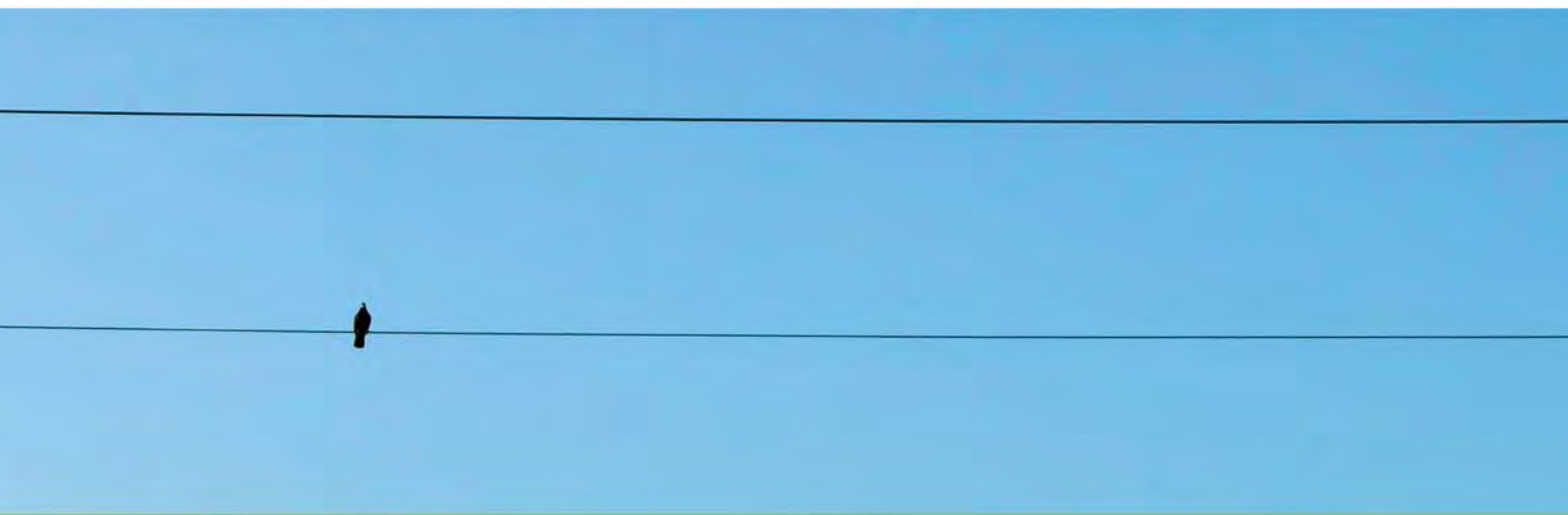

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Plugging In AMI

By: Michael McGrath
Executive Director
Retail Energy Services, Edison Electric Institute

The country's demand for electricity continues to grow. To supply it, America's electric utility companies are building more generation and transmission. But at the same time, with industry structural change, rising costs, and the need for even greater environmental protection, the industry recognizes that it must increase its commitment to customer energy efficiency as well. A crucial building block for a more energy-efficient future will be AMI — advanced metering infrastructure.

The nation's electric utility companies are now creating business models and regulatory mechanisms that will help make AMI a widespread reality. This is part of a broad-based campaign to enable energy efficiency to become a viable, sustainable business for utilities and other energy providers, Digital "smart" meters, two-way communication capabilities, automated controls, and sophisticated data management systems are rapidly improving the potential for information exchange between electric utilities and their customers. When coupled with innovative approaches to ratemaking and rate design, AMI can increase the industry's portfolio of resource options to meet the country's growing demand for electricity. It can more closely align regulated retail markets with competitive wholesale markets to deliver more cost savings. And it can become the foundation for a dynamic partnership between utilities and their customers to achieve greater reliability, power quality, environmental protection, cost control, and risk management.

ADVANCED METERING INFRASTRUCTURE

Advanced meters, or meters that are not visually read by a meter reader, have been around for decades. Some automated meter reading (AMR) systems consisted of a receiver that was mounted in a vehicle. As the vehicle was driven through a neighborhood, the data from the meters was read. These AMR systems reduced meter-reading costs, accelerated cash flow, and reduced the need for estimated bills. But once the meter data arrived at the utility, it followed the same path as data collected manually.

With an AMI, a utility can read almost any meter at any time, but its value extends far beyond simple meter reading. An AMI communicates through a fixed network that is in place all the time—it does not move. The meters are equipped with communication capabilities, usually radio or power line, but sometimes telephone, digital cellular or satellite. Meters using radio-based systems exchange information with data collectors located throughout the distribution system. Meters with power-line based systems communicate with data collectors located at substations. Both types of systems can in turn communicate directly with a utility's billing system, customer information system, and its outage management system.

An AMI's two-way communication capabilities give utilities and customers the potential to use time-based rates—such as time-of-use, seasonal, interruptible, and real-time rates—across the entire customer base. The benefits that arise from this capability are many and include:

- Cost savings for customers who shift their demand from peak to off-peak periods.
- Less stress on the transmission and distribution network at peak times, which can help to maintain reliability.

photo Courtesy Of Siemens

- A moderation in wholesale prices due to retail markets that include more price-responsive customers.

- Lower system peak demands, which in turn reduces the need for new peak generating plants.

AMI was given a boost by Congress with the passage of the Energy Policy Act of 2005 (EPAct). EPAct amended the Public Utility Regulatory Policies Act (PURPA). PUCs and the Boards of Directors of unregulated utilities were directed to take a fresh look at a number of issues, including a wide variety of time-based rate structures, and alternative rate forms, and net metering.

The 2005 revisions to PURPA also require PUCs and unregulated utilities to consider whether it is appropriate to create an AMI. If it is deemed appropriate, the PUCs may also set an advanced metering standard for utilities. Appropriateness was defined to mean whether the costs and the benefits to both the customer and the utility balance each other out.

Electric utilities have now begun moving toward creating an AMI. Last summer, Pacific Gas & Electric (PG&E) announced its plan to install 9.3 million advanced meters for its 5.1 million electricity and 4.2 million gas customers at a projected cost of $1.7 billion. PG&E's AMI is expected to be operating system wide by 2011.

One feature of PG&E's system is the ability to reduce peak load on the very hottest days by providing incentives to customers to shift electricity usage to a less critical time. This will reduce the company's need to purchase power for peak demand, lessen strain on the power grid, and reduce reliance on fossil-fuel-based generation.

To fund the AMI, the average residential customer with both gas and electric service would see a rate increase ranging from 49 to 99 cents per month for the first five years (or about 1 percent), with rate decreases each year afterward. Following this initial period, PG&E projects that future rates will reflect savings generated by the program.


photo Courtesy Of Siemens

For example, a typical customer who reduces energy use by 25 percent during peak hours will save about 10 percent on electric bills in the summer. PG&E estimates that only 15 percent of its customers will need to enroll in the meter program to offset 10 percent of its projected cost. The AMI also will make it easier for customers to enroll in a TOU program, which now requires the installation of a special meter and payment of a monthly fee.

An last November, PPL Electric Utilities (PPL) became the nation's first utility to obtain hourly usage from its entire customer base — nearly 1.4 million homes and businesses in Pennsylvania — when its new data management software system went live. Besides managing data from the hourly meter reads, PPL's system provides the platform for revenue protection, complex billing, forecasting, distribution management, load research, settlement, and customer energy management services.

Other PUCs have expressed interest in AMI, but due to the investment required, moving to an AMI will require utilities to offer a solid business case to proceed. AMI costs typically include the system hardware and software, new meters and meter-related utility equipment and labor, installation management and labor, project management, and IT support and integration.

Costs for the communication systems to read the meters are approximately $100 to $175 per meter. Adding demand response components (e.g., customer signaling, load control, other demand response equipment) adds another $100 to $350 per site. The systems to manage the AMI and integrate it with the utility's operating software systems are now being introduced, and the costs vary widely.

For utilities, the savings related to the reduction or elimination of manual meter reading usually constitute the single greatest benefit — accounting for fully one third to two thirds of the total AMI benefit. Some utilities are looking at an AMI for this reason alone. Other benefits vary significantly by utility, but can include the following:

- Accelerated cash flow.
- Revenues realized from new customer services.
- Reduced capital needed as the result of less manual meter reading and optimal transformer sizing.
- Savings realized through fewer billing inquiries and faster resolution of inquiries.

The societal benefits of AMI should be included in the business case as well. These include detecting outages faster; reducing energy losses due to theft, which are borne by all customers; and giving customers more control over their energy costs through AMI's demand response capabilities.

Electric utilities considering AMI should also look at its regional impacts. On the utility side, coordinating an AMI across multiple utilities in a region can reduce costs by allowing that region's power suppliers to benefit from economies-of-scale. Regional coordination may also ensure that utility systems can communicate with those of the transmission operator.

From the regulator's standpoint, a regional approach to creating an AMI can be helpful in a number of ways. It can promote uniformity in the way state PUCs in the region evaluate AMI benefits. And adopting a regional approach and the way they approach related policy issues—such as the throughput issue, the implementation of TOU, and the extent to which PUCs allow utilities to offer new products and services that AMI may enable.

The nation's electric utility industry is backing AMI for its operating and cost-saving benefits. But it is also promoting AMI as a way to use electricity more efficiently. EEI and its member electric utility companies are now collaborating to create the foundation for the business case that PUCs will need to make AMI a widespread reality.

This effort is part of a larger, industry-wide initiative to work with regulators, lawmakers, customers, and other stakeholders to develop a sustainable role for energy efficiency. Besides AMI, EEI and its member electric utility companies are focusing their efforts on four other areas that will also result in electricity being used more efficiently. These are:

- Fostering Smart and Efficient Buildings—Homes and commercial buildings account for over two-thirds of the nation's electricity use and over one-third of its natural gas use. The industry currently has many programs that encourage energy-efficient construction and remodeling, such as online energy audits and construction programs that offer incentives and training. These will be strengthened and expanded in the future.
- Promoting Smart and Efficient Appliances and Equipment—Home appliances and commercial equipment represent the fastest growing use of electricity. We are advocating for stronger/accelerated federal appliance efficiency standards. We are also encouraging greater tax incentives. And we will continue our own long-standing efforts to make high-efficiency appliances and technologies more popular and affordable.
- Supporting the Development of Innovative Rates and Regulation—Innovative ratemaking and rate design will be essential for customers and utilities to reap the full benefits of energy efficiency. To achieve this, the industry is encouraging new regulatory constructs and business models that will enable energy efficiency and demand response to be not only good policy, but also good businesses.

- Advancing Plug-In Hybrid Electric Vehicles—These technologies offer tremendous potential for both reducing our dependence on foreign oil, and for further reducing the nation's air emissions. The industry is collaborating with automobile manufacturers, suppliers, advocacy and governmental groups, and other stakeholders to bring the plug-in hybrid electric vehicle to the market.

To achieve its objectives in each of these areas, the industry is aggressively supporting federal appropriations. It is performing policy research on key state topics including net metering, alternative regulation, risk management, and rate design. And it is reaching out to the National Association of Regulatory Utility Commissioners and regional state regulator groups to encourage development of supportive state policies.

Building an advanced metering infrastructure will present challenges. But it, along with a new approach to energy efficiency, will benefit the customer, the utility, and society. It is time to begin. ■

About the Author

K. Michael McGrath, Executive Director
Retail Energy Services, Edison Electric Institute
mmcgrath@eei.org

Mike McGrath is Executive Director, Retail Energy Services, for Edison Electric Institute (EEI), which is the trade association of the investor-owned electric utilities and industry affiliates worldwide. EEI's U.S. members serve over 90 percent of all customers served by the investor-owned segment of the industry; generate approximately three quarters of all the electricity in the country; and service approximately 70 percent of all ultimate customers in the nation.

Mike has been with EEI since 1979. In his current position as a business unit leader, he is responsible for all EEI activities related to member utility and affiliate access and service to retail customers.

As such, he is active in areas such as business practices, affiliate transactions, energy codes and standards, customer services and operations, energy efficiency initiatives, and regulatory outreach. Mike has been a principal leader in the industry effort to develop retail uniform business practices.

Prior to joining EEI, Mike was a commercial marketing supervisor for the Potomac Electric Power Company.

Mike is a graduate of the Georgia Institute of Technology (Georgia Tech) with a degree in Mechanical Engineering. He has held several leadership positions over the years within the electric industry and in allied industries. He is a member of the American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) and has chaired ASHRAE's Owning and Operating Cost Technical Committee. He is also a member of the board of directors and an officer of the Geothermal Heat Pump Consortium.

Introducing the 2007 Automation/IT Leadership Series

Publisher's Note: *With this first issue of 2007, it is my pleasure to introduce a new feature focused on T&D automation and information technology: The Automation/IT Leadership Series. This series of interviews with top executives at leading utility automation and information technology companies will provide readers with valuable insights about how the automation/IT industry is addressing new challenges in the 21st century and how they are changing, adapting and investing to meet those needs. Mike Marullo, the Automation/IT and Utility Horizons editor for Electric Energy T&D, will conduct the interviews and deliver unique perspectives found only in EET&D. I trust you will find these dialogs both interesting and informative. As always, your feedback is welcome and encouraged.*

- Steven Desrochers, Publisher
Electric Energy Publications

David Jardine
Chairman &
President
Telvent North
America

Larry Stack
President
Telvent Energy

Welcome to the first installment of ***Electric Energy's Automation/IT Leadership Series*** – This series of interviews with top executives at leading utility automation and information technology companies will provide readers with valuable insights about how the automation/IT industry is addressing the new challenges of the 21st century and how they are changing, adapting and investing to meet those needs.

This month, our spotlight is on the executive management team at Telvent – a leading global automation and IT company with North American headquarters in Calgary, Alberta (Canada) and Houston, Texas (USA). Dave Jardine, Chairman and President of Telvent in North America (NASDAQ:TLVT) heads Telvent's North American operations. Joining Dave for this session is Larry Stack, president of the newly formed Telvent Energy. Several other changes are also in the wind at Telvent, so we are pleased to be able to provide insights from these key executives just as the curtain is unfolding on their vision and plans for 2007 and beyond…

EET&D: As an organization that has been through lots of changes over the past two decades, Telvent has managed to grow and integrate new products and even entirely new businesses without losing its central focus and momentum. To what do you attribute this resiliency and dedication to purpose?

Jardine: There are four key factors that I believe have allowed us to succeed in critical areas of organizational changes where many others have had significant difficulties and even outright failures. The first – and most important, I think – is the continuity of our core management team. Even though we have been through a number of ownership changes since we began in the 1970s, our critical mass of human resources has remained largely intact. This is especially important for technology companies; you literally lose decades of talent, experience and know-how every time someone walks out the door.

Second, we have carefully expanded our portfolio of products, solutions and services with targeted acquisitions in a way that have consistently delivered higher values through what we call deep integration. That is, pieces that fit a

specific set of needs as opposed to the common practice of buying other companies based primarily on financial metrics and hoping to make the synergy work after the fact.

Third, we've enjoyed continued success in growing the business profitably. Our long-term financial stability has allowed us to do far more of what we want to do rather than just what we have to do. Rather than being constantly distracted by basic survival strategies – a posture that has dictated the development path for a lot of suppliers to this industry for decades – our long-term stability has allowed us to maintain a tight focus on target markets while steadily increasing our footprint of products, solutions and services tailored to specific market needs.

Fourth, our customer relationships has remained strong and supportive of our vision as a global automation/IT provider. Besides the determination and commitment of a contiguous executive team, our focus on products, applications and solutions is routinely derived from very close relationships with our customers.

For example, we have a very diverse and proactive user group that has been instrumental in driving our R&D efforts over the years. This helps enormously to gain rapid product acceptance rather than depending on massive market pushes to accomplish that same objective. Moreover, our strategic focus is to develop Telvent as a business partner to our customers and support them to the best of our ability as they face enterprise integration challenges, whether rooted in regulatory compliance, security, environmental issues, technology, efficiency or other areas.

And finally, we have maintained a personal discipline across our organization to meet our commitments to all stakeholders. Simply stated, we pride ourselves on doing what we say we will; everyone at Telvent is committed to that principle.

EET&D: I also understand that Telvent has put a new corporate structure in place for 2007. Can you shed some light on how this new organization might affect the marketplace at large for our readers?

Jardine: I should probably start by giving you a quick overview of what we're doing at the corporate level, since the goals and objectives for our energy market involvement are substantially driven by Telvent's global IT vision addressing multiple market sectors. The new structure organizes the company into five major operating units, each of which has a global mandate:

1. Energy
2. Environment
3. Transportation
4. Public Administration & Health Care
5. Outsourcing

As part of this realignment I'm very pleased to announce that Larry Stack, a 27-year veteran of our organization who was previously Executive Vice President & CTO, will be leading Telvent Energy. This new Energy business unit includes electric, water and gas utility, and telecommunications, as well as oil, gas and petrochemical markets. I'll turn this over to Larry for more on the role of Telvent Energy in 2007 and beyond…

Stack: Telvent Energy will bring enhanced talent, focus and resources to these vital market areas and will have the full dedication and support it needs to further expand its products and services, while continuing to provide top rate support for our installed base of SCADA, process automation and IT installations worldwide.

Like our other businesses, Telvent Energy is a global entity that will draw upon centers of excellence from around the world to help solve the industry's most daunting problems. Telvent Energy comprises our second largest business unit bringing together R&D, Product Management, Operations, and Sales & Marketing resources from all parts of Telvent's global operations.

EET&D: What about Telvent's current and future customers in the energy and utility marketplace? What should they expect the impact of this new Telvent Energy organization to be on those special relationships?

Jardine: Telvent Energy represents one of the broadest and most integrated sets of automation/IT-centric products, services and value-added solutions available across the energy and utility marketplace. Moreover, it leverages our geographically diverse customer base and expertise accumulated over more than three decades of involvement.

Clearly, the challenges we face as an industry are in many ways unprecedented and will require much more than just technological ability to meet and overcome; financial and organizational strength will also be vitally important ingredients in the success of any company involved in the automation/IT business.

From this point forward, solving the changing – and arguably the most challenging – needs of energy and utility enterprises must be backed by strong, stable organizations capable of delivering fully integrated products, solutions and services with a greater depth and breadth than ever before.

EET&D: Shifting now to the energy market itself and the electric utility sector in particular, what do you feel are the biggest challenges that utilities face when it comes to automation and IT planning, design, implementation and support over say, the next 3-5 years?

Jardine: Well, that's quite an all-encompassing question, so let me address some broad issues first, and then Larry can probably add more detail from the Telvent Energy perspective.

Obviously, all of the challenges that utilities are facing would make for a very long list, but I believe that the integration of real-time operational systems with the business IT systems needed to facilitate business decision making in a timely, consistent and effective manner must certainly be near or at the top of that list.

As an automation/IT supplier, we believe in the concept of "meter-to-boardroom" process and data continuity across the IT infrastructure and security perimeter including data validation, enterprise integration with legacy systems and timely data delivery to critical customer service processes.

Over the last few years Telvent has both developed and acquired specialized technologies and expertise in traditional data acquisition subsystems, enterprise GIS, and mobile workforce solutions as well as advanced operational and business applications. These strategic investments allow our customers to take a series of incremental steps that not only ease the technical, operational and economic burdens of system migration in the short-term but that also buy valuable time needed to deal with the longer term problems precipitated by lagging T&D investment, workforce deficits and security enhancements for critical infrastructure.

Within that context, there are at least three areas of attention that immediately come to mind; those being Security, Human Resources and Communications. Larry may have some others to add, but those three are key in my mind.

EET&D: Okay, let's take those one at a time, starting with Security. How do you see the security issue ultimately being resolved with so many critical infrastructure systems already deployed and so many new ones coming on line? And, is it feasible to retrofit legacy installations or is that just a futile exercise?

Jardine: Security issues hit the industry like an avalanche following 9-11, so Telvent (as did many companies) initially tried to retrofit existing systems with levels of critical infrastructure security that we felt could be both acceptable and affordable to our customers. We quickly found that to be an insurmountable task since security requirements and standards were then – and are still – evolving.

It soon became obvious that following a path of putting band-aids on existing systems would result in something that would quickly become inflexible and ultimately impossible to maintain as the industry adapted to the changing requirements. So, we went back and built security and the corresponding standards into the lower levels of system platforms based on which future applications could accommodate both a suitable and an acceptable level of security for each application.

EET&D: Another issue that has gotten a lot of press lately is the looming human resources crisis. We all know that the utility industry stands to incur an unprecedented loss of people, talent and experience over the next decade as Baby Boomers retire. How do you see the industry bridging this gap, especially at a time when engineering and computer science graduates are at an all-time low?

Jardine: Well, most importantly, I think it's a given that automated solutions can no longer be perceived as merely an available option, but instead must be embraced as a vital set of problem-solving tools. As you may recall, we had an extended low-to-no hiring period during the "right-sizing" craze, which began in the early 1990s. That hiring gap left a staffing dead band spanning up to ten years, further exacerbating the disruption of what I call the "human architecture" of the enterprise. As a result, automation will have to bridge the widening gap between front office and back office functions that were previously fulfilled by people.

EET&D: Let's move on to communications technologies – and the corresponding standards – that are being cranked out at a feverish pace as well as the utilities' rising interest in broadband over power line (BPL) and other leading edge alternatives to leased lines and radios. Where do you think future automation/IT networks are headed?

Jardine: Utilities will be making some landmark decisions over the next few years regarding the selection, procurement and deployment of communications technologies. Clearly, there are many choices available, but not all necessarily help utilities manage their telecommunications and information technology systems with the same level of efficiency. In the past, communications solutions have typically been evaluated separately from automation/IT initiatives, but unless utilities make communications an integral part of a total integrated business solution, the outcome probably won't deliver the desired results or benefits. Larry may want to elaborate further on that point…

Stack: Let me just add that I believe utilities should first identify and leverage the opportunities already residing in their existing communications infrastructure. But, at the same time, they must also recognize that large telecommunications infrastructures might no longer deliver the desired cost effectiveness or a proper fit for all of their future enhancements or expansion needs.

When evaluating newer communications platforms, utilities should make selections based on the ones that can best meet their future plans while supporting their business model and its economic goals across the applications that will use those platforms rather than just focusing on just one application or only a single technology.

That is, future communications solutions will often involve multiple technologies including wired, wireless, radio, broadband, etc. working in complex meshed networks that allow the user to gather and distribute information whenever and wherever it may be needed on a virtually instantaneous basis.

EET&D: Is there anything else either of you would like to add to the discussion before we end?

Jardine: Yes, I think we should probably say something about the amount of time and money that has been – and will continue to be – spent on preventing future outages, especially those on the scale of the August 2003 Blackout. In particular, I want to point out here that there are also some implications for security.

One of the keys to improving both pre-emptive strikes and emergency response is the use of more accurate and timely information. Most legacy OMS projects were very focused on good performance for specific dispatching operations, but did not have that same degree of focus on data utilization, openness or integration.

The fact is, building and maintaining a highly detailed picture of the network has typically been more than most companies could do, and bringing in real-time and highly aggregated historical data was a pipe dream for many. As a result, many companies were – and are still – operating today with a very limited picture of the electrical network (e.g., primary backbone only or highly simplified secondary networks), with little or no real-time or actual historical data, even though the tools are there to take it to the next level.

Stack: That's right. I'll just add that the best performing utilities of the future will use spatial data to model the details of electric networks, thereby sustaining and improving that data as a part of their normal workflow. By marrying that spatial information with accurate real-time and historical data, managers and dispatchers will be able to use that information in a decision support system to make real-time and "near-real-time" choices about the best way to improve network performance and reliability.

EET&D: One last issue that we've been watching closely is the ongoing debate over operating system alternatives and selections. We've seen the transition from proprietary operating systems for automation/IT to UNIX and eventually to Microsoft Windows. Now, many are saying that Windows is a security disaster and Microsoft's soon-to-be-released Vista OS – though reportedly better equipped to deal with malware – leaves a lot of questions unanswered, pending its formal release. Meanwhile, Linux has also made steady advances into the automation/IT environment. Do you have any final comments on this topic?

Jardine: Mike, I'm afraid I'll have to answer that question with another question, not only so your readers will have something to think about, but also because the question may not have the kind of answer you might otherwise expect. Consider this: As the data acquisition and control subsystems and advanced application environments of the future become truly integrated functions of the business IT environment, will the operating system even matter?

EET&D: Good point. Maybe some of our readers will be inclined to address that question and share their views on this controversial topic with us in a future issue. (Please send your comments to *MAM@ElectricEnergyOnline.com*.)

Large Scale Substation Automation: Overcoming Technical Challenges

By: Lee Melville, project engineer, Enspiria Solutions, Inc.

Integrating components for substation automation at a handful of substations can be achieved with custom fit solutions for each integration effort. Automation of dozens of substations, on the other hand, requires a systematic approach involving the application of data and integration standards and disciplined project management and engineering processes. The use of proven systems for large scale implementation, combined with an experienced systems integration team, helps ensure the realization of enterprise wide benefits.

There are many substation automation architecture choices available today providing varying levels of redundancy and scalability, but the application of standards and process to implementation of the selected architecture is critical. Successful large scale substation automation must start with data and integration standards, and include planning for change. Comprehensive factory testing, efficient installation techniques, and effective scheduling are also critical to the implementation of large scale projects.

START WITH DATA AND INTEGRATION STANDARDS

With the wealth of information available from IEDs and other devices currently being installed in substations, data serves the needs of many people. In fact, with regards to the diversity of stakeholders associated with a project, substation automation is one of the most complex undertakings a utility can perform. Defining the integration of these devices demands the involvement of all stakeholders to register their requirements.

Structured data modeling is necessary not only for each type of device that will be integrated into the substation automation system but also for the functional configuration of that device. For example, a protective overcurrent relay could be used to protect feeder level circuits or subtransmission level circuits – these two functions should be defined in separate data models.

Structured data modeling ensures a base standard from which to drive the combination of

substation components into an integrated system. Communication protocols such as IEC 61850 provide comprehensive data modeling for the information out of devices that utilize this protocol, but the complete substation automation upgrade goes beyond this.

The data modeling exercise should incorporate the following factors:

- Presentation of information to the Enterprise
- Configuration of IEDs
- Presentation of information at the substation interface
- Presentation of information to SCADA
- Automation within the substation
- Communication protocols employed
- Protective circuit design

All of these factors should make up the data model which is utilized to create the various configuration builds for any particular substation architecture. Each of these categories should be well documented in templates or design standards which are well understood and agreed upon before they are put into practice.

PRESENTATION OF INFORMATION TO THE ENTERPRISE

The newer, processor based, IED devices provide exponentially more data/information than the previous generation of equipment. Substation automation systems play a critical role for utilities by leveraging IEDs for capturing real-time and time stamped historical information, providing a foundation layer for delivering the critical data to the utility knowledge infrastructure (see Enterprise-Wide Data Sharing graphic). This enhanced availability of station data enables utilities to make business and operating decisions more accurately and quickly, and to improve the quality of service provided to customers, while maintaining acceptable levels of risk and reliability.

Due to the likelihood that substation data is going to all feed into a small number of central databases, depending on the external repository architecture, the information from each substation has to be consistent in format and scope. The means of gathering and storing this data in the substation must therefore also be consistent to ensure that the same communications interface can be used between substation and external databases.

CONFIGURATION OF IEDS

Modern IEDs are capable of providing a vast amount of information to the local HMI and remote SCADA interfaces. Before a standard configuration plan can be formed for each IED, the enterprise wide data requirements of the utility need to be determined. Examples of the major areas of the enterprise that use data include real-time fault dispatch, load management, reliability maintenance, asset planning and revenue management.

Once enterprise data requirements are defined, configuration decisions such as variable assignment and hardwired input utilization can be determined, based on the capability of the IED, redundancy standards and data quality requirements. Spare capacity for future additions should be part of every configuration.

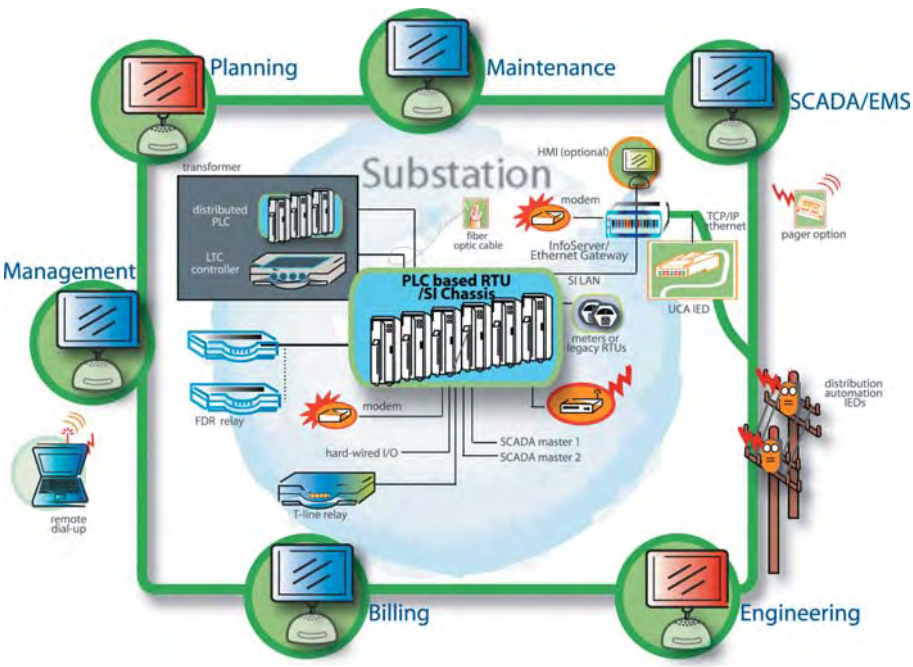
Many modern IEDs are capable of supporting millisecond time stamped hardwired inputs which can replace data concentration devices. This could be used as a primary means of concentrating hardwired inputs, or in conjunction with other data concentration devices, or not at all, depending on the design principles which include scalability planning. The device used to concentrate hardwired inputs should also include spare capacity. Whatever the design principles may be, the same relay configuration should be used for a specific IED and its assigned protective function. In other words, a certain model IED used to protect a bank will employ one standard if all banks can be considered the same. This is unlikely however, so new standards based on a variation of the core bank model would be needed, such as the inclusion of load tap changers.

PRESENTATION OF INFORMATION AT THE SUBSTATION INTERFACE

Modern HMI software should support alarm configuration to allow the substation user to prioritize alarms, define their behavior, define analog limits, standardize nomenclature and graphical image, to name a few items that contribute to the operability and presentation of HMI information. Users at the substation should be able to walk into every different substation and find a standard configuration applied to every component in that substation. Of course, differences will exist in areas such as bus architecture, so allowances in the data model should also be made, to a reasonable extent, for typical architecture categories.

PRESENTATION OF INFORMATION TO SCADA

The level of real-time detail available at the local substation interface is more than what is required for communication to SCADA. Certain types of points may simply be grouped together into logic points so that only one alarm is presented to SCADA in the event that one alarm



in a group becomes active. Other points may not need to go to SCADA at all; others may need to be sent with the addition of a timestamp. These decisions should be made with the function of the SCADA dispatcher in mind – what level of information is needed so that the dispatcher can assign the correct crew with enough information for them to be properly prepared, whatever problem the substation is experiencing. The principles of communicating with SCADA should be standardized across all installations.

AUTOMATION WITHIN THE SUBSTATION

PLC or other logic based controllers allow the ability to automatically switch within a substation in response to pre-defined events or triggers. Logic "building blocks" should comprise clear rules that are low level enough to be assembled around the various designs present in the utility's substations.

COMMUNICATION PROTOCOLS EMPLOYED

Due to the availability of multiple communication ports on substation devices, redundant communications is feasible and provides increased reliability and separation of relay communication features. One port can be used primarily for data transfer while the other ports can be used for relay maintenance (loopthru), failover, fault record transfer, mirrored bit or other functions that are important but whose separation from real-time data flow may increase the efficiency of this primary data flow function. Certain protocols will not support a full range of potential SCADA data, such as pulse accumulation, so obviously the device model used should include protocols that fully support the data, or appropriate protocol conversion will be needed.

Employing diversity of communication protocols among ports, and diversity of data concentration devices connected to these ports, will guard against common mode failure. Communication redundancy also extends beyond the substation, up to the SCADA Master. The advantage of communication redundancy is not only the failover ability but also the minimized duration of SCADA outage during maintenance on either communications path, at any point along the path inside or outside of the substation. This certainly helps the time pressure associated with continuing automation enhancements once communication is established, as it allows more flexible upgrade scheduling when communication down-time is minimized.

PROTECTIVE CIRCUIT DESIGN

Wiring standards for the integration of an IED and it's connected components (such as blocking switches, terminal blocks, current transformers, etc.), specific to the protective application, are established to allow for consistent design and construction practice. Consistent design leads to consistent construction practice. Installation errors due to inconsistent design can result in significant setbacks during cutover, potentially leading to damage or unplanned outages.

PLAN FOR CHANGE

Large scale implementations last multiple years, leading to complicating factors such as hardware obsolescence, firmware upgrades, software upgrades and protocol improvements during the course of deployment. No matter how much effort is put into defining requirements and staying focused on scope, change is inevitable. Fortunately, change can be beneficial if managed correctly.

Effective communications is key to managing change. Before any automation or upgrade work proceeds, a change control board should be formed with at least one member from each group of stakeholders that was involved in the formation of requirements for the project. The end result for most changes is a revision to one or more templates or design standards – essentially an update of the data model. Decisions regarding the implementation of changes across a large number of substations in varying stages of design or installation have far reaching ramifications. Separate change/retrofit plans are required depending on this status and the nature of the change.

As mentioned previously, planning at the IED configuration and data concentration level should include spare capacity for future additions. Adding a few hardwired points will not require much in the way of process to manage. Adding IED points may require more however. This is one of many drivers for change in substation automation.

Changes to plan for include configuration changes and component changes. An effective rollout procedure expedites change implementation.

CONFIGURATION CHANGES

An example of a configuration change would be a change to the IED point configuration. For substations already upgraded, a retrofit plan will be needed to ensure minimal interruption to the service of each substation. The same retrofit plan could be applied to substations undergoing an upgrade, but without the same restrictions on limiting down time. Substations undergoing factory testing should be completed to the current configuration and then undergo the change with regression testing applied to any part of the system that is affected by the change. For substations in the design or build phase, the configuration change should be made before testing starts.

COMPONENT CHANGES

An example of a component change would be an upgrade to a software module, or a hardware component. This type of change should be made in the factory first, to ensure that the change is robust and results in the desired outcome. The change should be made on a system about to undergo testing, so that a full factory test can be made with the change in place to better ensure its quality. Regressive testing should also take place which will be described in the next section. The factory environment cannot fully simulate the real world utility environment so the next step in approving the change would be to implement the change on a test system integrated to the SCADA network and as many typical substation components as possible.

ROLLOUT PROCEDURE

Efficient implementation of a change requires the ability to remotely access the substation automation system, to reduce "windshield" time and ensure quick rollout across the substation network. Many substation components, such as GPS time clocks, now provide a communications port for maintenance purposes. If the automation system includes a PC or other device capable of connection to these maintenance ports, the scope of remote maintenance is increased beyond simply the configuration of the HMI and SCADA interface. Redundant communications to the station and IEDs will also allow remote maintenance of IED settings with little or no risk

of impact on primary data communications.

FACTORY TESTING

The fastest way to test a system is to make sure that it is as close to error free as possible, before you test! System build and configuration procedures must be well documented, comprehensive and repeatable for this to be achievable. Attention to this detail will result in a quality product for site installation and acceptance testing. The physical hardware assembly must match the design of course so a system inspection is necessary upon receipt of the build. This step will save time over troubleshooting hardware issues whose symptoms may be the result of many possible problems.

Once inspection is confirmed, configuration will take place according to procedures that are documented and physically signed off after each step. This creates a factory configuration history that can be verified before testing begins. Similar documentation should be utilized for the actual testing, so that sign-off of all steps can be verified before site installation.

Factory test procedures should be designed to test the complete configuration of the integrated system, rather than the complete functionality of all system components. Each system component should go through complete functionality testing once, but is not needed on an installation basis. If a system component is upgraded, regressive testing on this single component should be performed one time to verify the complete functionality is still intact.

EFFICIENCY OF INSTALLATION

Site installation relies on comprehensive work construction plans and consideration of existing substation conditions for ease of cutover. An initial site meeting should take into consideration the components to be removed or replaced and the best design standard to apply. Replacement of relay panels will be much simpler if the existing supporting structure can be re-used for the new panels. The structure of the panel design could be modified as a variation to allow for a more "plug-and-play" approach, while the wiring standard for the panel remains the same.

Site acceptance testing requires coordination between many different people so the procedures for this testing will require similar quality assurance to that used in factory testing. Site acceptance testing includes an important additional component; authority for conducting each step of the test procedure must be well established because of the risks associated with working in a substation environment versus a factory environment.

Additional techniques can be used to improve the efficiency of installation, once the reliability is established through procedure and authority. One such technique is the use of "dummy" IEDs to conduct testing without directly affecting critical substation components. This can establish a correct configuration so that the actual test involving the critical component can be carried out with a higher level of confidence. Due to the paramount importance of the protective responsibilities of IEDs in a substation, another technique would be to provide a single point of access for technicians responsible for IED maintenance. Instead of requiring a relay technician to directly connect to the maintenance port of an IED during site acceptance, to support ongoing testing, communications from each IED can be feed back to a central location in the substation near to the local interface. This allows the relay technician to easily communicate to all IEDs within a substation from one point and be more closely involved with the other members of the testing team. This local interface will need to provide some sort of blocking mechanism to the remote loopthru interface to prevent conflicts.

SCHEDULING

Scheduling is critical to the implementation of large scale automation projects. There are many teams involved in the overall work flow so the project processes to achieve each milestone in commissioning a system should be documented. These processes would include roles and responsibilities of every team member, deliverables required at each stage of the process and clear timelines to ensure that parallel processes are synchronized.

If the site installation process falls behind, systems waiting to be installed will build up which complicates retrofit plans for approved changes. If design or factory testing falls behind, construction teams could be left with no work which could result in their re-assignment to work outside of the substation automation upgrade project. Delays will likely occur at every stage in the project process so the scheduling should include some buffering to mitigate this risk.

If the throughput of each stage in the project is sized and matched to the other stages, the workflow from design through to commissioning can be leveled.

A seasoned systems integrator can provide discipline and experience for large scale automation projects. Internal utility teams that are fully capable of dealing with single implementation type projects may not be prepared to handle multiple projects. A systems integrator brings tailored best practices to help the utility achieve maximum value from their substation automation investments, and to reduce risk of applicability, implementation and acceptance. ■

About the Author

Lee Melville is a project engineer with Enspiria Solutions, Inc. He has 10 years of experience in the electrical utility industry, and specializes in the integration of substation automation systems. Lee holds a B.E. in Electrical Engineering with honors and an M.E. in Engineering Management from the University of Canterbury (Christchurch, New Zealand). His experience includes positions with UnitedNetworks Ltd., Power New Zealand, and Tait Electronics. lmelville@enspiria.com

Interview with Sharon S. Allan, President of Elster Integrated Solutions (EIS)

Mike Marullo (Electric Energy T&D magazine's Utility Horizons editor for automation/IT)

AMRA International's 2006 Autovation Conference was held in Nashville, TN on October 22-25th. During the conference, Elster (www.elster.com), held a press briefing to announce several major changes and new developments with broad implications for not only Elster itself, but also the entire AMI/AMR/MDM (advanced metering infrastructure, automatic meter reading meter data management) industry for electricity, gas and water.

Shortly after the conference, **Mike Marullo (Electric Energy T&D magazine's Utility Horizons editor for automation/IT)** caught up with **Sharon Allan, the newly appointed president of Elster Integrated Solutions (EIS)** to better understand what these changes mean for Elster and also what they might portend for the rest of the industry. Following is the transcript of the interview, conducted in early November...

EET&D: Sharon, EIS was itself created amid the many other changes and appointments as announced in Nashville. As the newly appointed president of this new operation, perhaps you could begin by putting the mission and vision of EIS into perspective for our readers.

Allan: Let me begin by saying that we have moved into what I believe is really a new era for the utility industry. That is, until just a few years ago the vast majority of the coverage general business publications like the Wall Street Journal gave to the utility industry was stories about a handful of high-profile companies like Enron. By contrast, today we are seeing coverage of topics like green power, energy conservation, performance-based ratemaking and other aspects of the utility industry rapidly gain momentum and the attention of the public at large. I think this is an important change because people are becoming more aware of the role utilities play in their daily lives than ever before, and that has important implications for how we conduct our business.

EET&D: So, how is Elster reacting to this new level of awareness?

Allan: A fundamental underpinning of the mission and vision for EIS is to embrace this increased awareness and bring together what has historically been a group of loosely connected businesses under one umbrella with the Elster brand at its core. I guess you could literally say that "Integration" is our middle name for a reason; that being our goal of presenting a diverse, yet cohesive solution set to all of our customers, regardless of which aspects of metering or associated technologies they might currently be exploring and/or are already committed to deploying and supporting.

EET&D: Could you perhaps identify some of the factors that are behind this heightened awareness and how your role in the industry might be mitigated by those factors?

Allan: Today, electricity and water (and in many instances, gas as well) are relied upon to facilitate and sustain virtually every aspect of our personal lives and business activities. Now, more than ever, we depend on these commodities to be there when we need them since they are so essential to our overall prosperity and well being. Therefore, we see our role being much more than just reliable purveyors of meters and metering technologies. We truly feel that we (Elster) and our entire industry are engaged in managing the necessities of life, a responsibility we take very seriously. So, we are reshaping Elster to serve the wants, needs and expectations that are evolving as a result of steadily increasing dependence on and demand for those basic commodities.

EET&D: Are there any specific factors that stand out as being key to the changes we are seeing (or will see) in say, the next 1-2 years?

Allan: Yes, two things stand out that I think will have a huge impact over the next couple of years: 1) Declining infrastructure and 2) aging workforce issues. Let's take them one at a time:

First, the declining infrastructure has a broad range of implications, not the least of which is the burden on already strained utility resources, both operationally and financially. This, in turn, is driving a need for business transformation. That is, we need to find better and more efficient ways for delivering proven solutions across company boundaries so as to not unnecessarily duplicate efforts and reinvent things when an integrated approach will suffice. This is especially true where combination utilities (i.e., electric, gas, water) are concerned. At EIS, we are striving to provide a more holistic approach that recognizes the differences while capitalizing on the similarities. Admittedly, this is no small challenge, but the creation of EIS represents a solid first step in that direction.

The aging workforce issue is one that cannot be overstated. With so much talent walking out the door of utilities every day, we have to find a way to quickly and efficiently get real-time information into the hands of those who need it while recognizing that these individuals will probably not have the same level of experience as their predecessors. Therefore, our products and services have to be delivered at just the right level and in the just right form or the benefits will not be realized as intended.

EET&D: That last comment raises an interesting point that is currently being debated in supplier and utility circles throughout the industry. That is, the proper order for implementing AMI and MDM; what is your view on that, Sharon?

Allan: Well, let me first say that there are certainly some strong arguments for putting meter data management in place before pulling the trigger on advanced metering infrastructure projects. Yet in my view – which again, is not intended as a blanket statement that applies to all cases – there are equally compelling reasons why the opposite may work better in some instances. With so much happening right now and for the foreseeable future from a technological perspective, it's hard to know what you might want to do with all that information prior to actually seeing it. Very often, reading about what a new system is capable of doing pales by comparison to seeing it in action. So, until utilities start actually experiencing how interval readings, better meter accuracy, improved billing efficiencies and business analytics can be applied to meet their short- and long-term objectives, many of those things will be hard to visualize.

EET&D: What is technology's role in all of this? How will technology fit into facilitating the business transformation that needs to take place?

Allan: It isn't so much technology per sé as it is the pace of technology. These days there is a lot of effort being put forth to establish standards, and for all the right reasons, I might add: Interoperability, maintenance and support issues, just to name a few. However, the "shelf life" of most standards is only about 18-24 months. In the metering business, rate cases are based on foundations that have traditionally been expected to remain constant for 10, 20 or even 25 years. To tether a major AMI deployment and its associated business case to standards that may be outdated before the ink dries on the rate case just isn't very prudent. Obviously, some potentially radical adjustments will have to be made to accommodate the realities of today's – and especially tomorrow's – fast-paced technological advancements, but arbitrarily mandating standards are probably not the best way to solve those problems.

EET&D: But doesn't Moore's Law – the notion that technology advances at an exponential pace – apply here and make some new things economically feasible that weren't before?

Allan: Well, yes, that's true on a certain level. However, over the years a lot of people have tried to apply the idea that memory and computing power were free to the AMR equation and thought justification would be a cake walk on that basis. What a lot of AMR practitioners eventually learned is that while microelectronic components might be almost free, bandwidth is not. There is a point at which the cost to backhaul the huge amounts of data produced by the microelectronic devices (electronic meters, in this case) becomes prohibitive. That said, recent and ongoing advances in communications technology are also driving down costs, so there may yet be a happy ending to all of this.

EET&D: So what's the key to harnessing the benefits of all of this new technology without winding up on a dead-ended road?

Allan: At end of the day, the trick is to work within a well-defined but fairly loosely coupled network environment that leaves the door open to migrating into new solutions in the future without starting over. Elster is moving along that path by leveraging our building block approach and also developing a more integrated architecture that embraces electric, gas and water solutions.

EET&D: Okay, let's move over to the customer side of the market. Do you think that customers are really ready to embrace the kinds of things that AMI can offer, particularly in terms of conservation and efficiency initiatives?

Allan: At this point, the battle for control of the electronic customer services gateway is still raging, and there is no clear winner yet. Moreover, regardless of who eventually secures that position – utilities, telecom companies or the consumers themselves – one thing is clear: Consumers will ultimately decide what they will or won't accept from the companies providing the basic commodities relative to conservation and efficiency. Over the past several years radical changes in price points for advanced metering technology have precipitated some rather dramatic changes in what is considered acceptable. There is clearly a rising tide of awareness among consumers regarding energy conservation and efficiency that will help to drive these initiatives forward, but the technology will have to make it cheap, flexible and easy to use. Naturally, it will also get a boost from the migration from electro-mechanical meters to electronic meters, which is ongoing.

EET&D: So, to sum things up, what do you see in the immediate future – say the next 1-2 years – as being the most likely trends or new developments in metering and related business areas?

Allan: I don't have a crystal ball, but I think we can assume that the consolidation of the supplier side will definitely continue, getting down to probably not more than a handful of major suppliers – perhaps two or three – fairly soon. The main objectives will be the ability to have what I'll call Scale and Breadth. Most utilities absolutely must have scalability to be able to deploy incrementally and also product/application breadth to be able to accommodate the many unique aspects and idiosyncrasies of their operating environment across their respective service territories. Also, the integration of a broad and diverse set of legacy meters was a big problem about 5-7 years ago, but as electronic meters have replaced ones, the integration task has become a lot easier, so I think we'll see some accelerated market expansion.

EET&D: Does the migration to electronic meters apply across all three verticals (i.e., electric, gas water)?

Allan: Water systems have a rather unique problem in that water meters tend to wear out over time. That's because the water flowing through the meters wears down the impeller and impurities in the water can really gum up the works too. This helps to increase the replacement rate, but there are a huge number of water meters deployed so the effect is very long term. Conversely, gas meters last a long time and unlike electric meters, are automated externally, so most of that market usually involves retrofits of the AMR but not the meter itself.

EET&D: Anything else you'd like to add, Sharon?

Allan: Yes, I'd like to say that I believe we are seeing the beginning of a wave of new market initiatives, new technologies and new solutions, and Elster intends to be at the forefront of those changes – and providing solutions to the new challenges that will inevitably emerge. So, for now I'll just say this: Stay tuned for further developments…

Sharon Allan
President Elster Integrated Solutions
sharon.s.allan@us.elster.com
www.elster.com

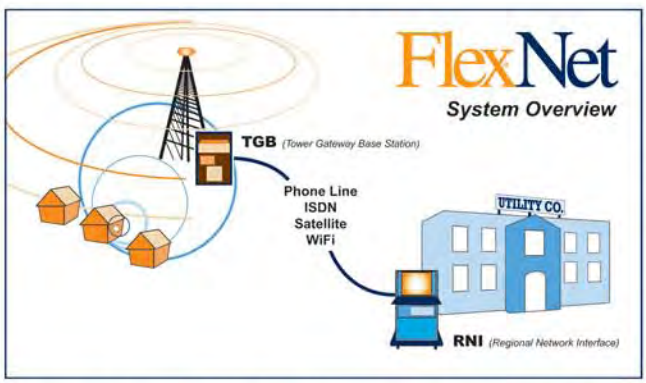
AMI Systems Stand at the Forefront

Sensus Metering Systems is positioned to execute the company's vision and solidify itself as a premier Advanced Metering Infrastructure (AMI) systems provider. Over the past decade plus, the company has transitioned itself from a premier supplier of AMR (Automatic Meter Reading) and metering products and services, to a leading high tech AMI/AMR systems solution provider to all major utility markets. The basis for Sensus Metering Systems' value is intelligent, communicating meters, linked systems and superior customer satisfaction.

Culminating with the acquisition of Advanced Metering Data Systems (AMDS) in June 2006, Sensus has captured major electric contracts featuring the AMDS developed FlexNet system – an AMI network that functions across electricity, gas and water utilities.

"The purchase of AMDS' assets took us to the top of today's radio-frequency fixed network AMI systems and complemented our existing AMR and metering products and services," says Dan Harness, CEO and President of Sensus.

FlexNet, a radio-frequency fixed network utility meter reading system, increases meter reading efficiency, reduces overhead costs, and enhances customer service. Its two-way and one-way fixed-based monitoring can provide up to 300 square miles of coverage from one network tower. The patented technology allows for Internet-based programming of the network and meter endpoints. And the system is scalable to accommodate growth of a utility.



Shortly after acquiring AMDS, Sensus signed an agreement with Southern Company, an electric utility serving the Southeastern United States, to deploy FlexNet across Southern's territory of Alabama Power, Georgia Power, Gulf Power, and Mississippi Power.

Sensus also experienced a flurry of activity in Canada. Over 25,000 FlexNet-enabled iCon meters are slated for Newmarket and Tay, Ontario. Newmarket Hydro, recognized as a pioneer in the Ontario electricity market, selected the FlexNet AMI solution for full deployment. And, 80,000 meters were purchased by electricity provider PowerStream for the York Region of Ontario.

John Sanderson, PowerStream's Vice President, CDM and Metering, said: "We chose Sensus' FlexNet system because it satisfies our stringent technical requirements, utilizes minimal network infrastructure; and is a true multi-utility platform, which communicates over a secure licensed spectrum."

Sensus and its FlexNet system have impressed electric utilities enough to earn participation in several utility AMI system pilot programs from coast to coast.

Smart Meter Pilot Program Inc. (SMPPI), a nonprofit company led by Pepco Holdings, Inc, electricity provider to the Washington D.C. area, selected the Sensus FlexNet system and iCon electricity meters for a smart-metering pilot project slated for over 2,000 homes. New FlexNet-equipped iCon meters will go into homes in Pepco's D.C. coverage area. The project is meant to give Pepco more data about residential consumption habits and trends, and give homeowners better control over their usage. The project is pending for expected final District of Columbia PSC approval.

Hawaiian Electric Company (HECO) officials also are piloting the FlexNet system under a plan that allows customers to control their own electricity usage and billing.

New Enhancements Released

As FlexNet solidifies its place in the AMI industry, two new enhancements are designed to heighten AMI functionality for electric utility companies.

A hot-socket detection feature, using a built-in internal temperature sensor, addresses safety and customer service issues. When an electricity meter overheats, it sometimes melts and shuts down the meter. The hot socket warning alerts a utility company about the situation in real time. The utility can then respond as the condition occurs, improving customer satisfaction.

Second, a meter location feature allows a meter to be tracked after being moved from its original location in the field. FlexNet uses a poll command to determine position and signal strength of the meter relative to other nearby meters of known location, enabling identification of the misplaced meter's location.

Both enhancements are designed to work on a FlexNet system that incorporates Sensus' solid-state electricity iCon meters.

"FlexNet is already a great solution for utilities, but these new features allow a utility to offer its customers the highest level of productivity, accuracy and service available in the metering systems industry," said Marc Reed, Director of Communications Technology at Sensus.

More about FlexNet

The FlexNet system's two-way features include demand reads, kWh and actual voltage measurements, programmable read interval, low-voltage and breaker re-closure warnings, outage and restoration notification, Internet-accessible, on-demand meter functions, remote meter disconnect/reconnect, 15-minute interval data, real-time clock calibration for top-of-the-hour reads, TOU billing and consumption correlation, energy management programs, text and rate change notification, load shed and restore, and real-time data for management and billing. FlexNet also offers integrated gas and water modules for both multi–utility and individual gas and water utility applications.

Network deployment is also simple with the FlexNet system, as it uses existing tower infrastructure and eliminates the need for company technicians to deploy the network. This eliminates the need for piggy-backing onto the utility's distribution system. And by operating on protected Federal Communications Commission (FCC) primary licensed spectrum ensuring maximum transmit range and providing protection from potential radio interference from outside parties, FlexNet requires the least amount of network locations which minimizes ongoing operational costs.

These features and benefits are available with the FlexNet system today and the system is designed to be expanded and enhanced for additional capabilities in the future. Sensus is driving the vision.

Sensus FlexNet

Flexible to meet your dynamic AMI expectations.

The Sensus FlexNet Advanced Metering Infrastructure (AMI) technology is truly based on flexibility. This comprehensive fixed network solution takes into account that **your information needs aren't static;** nor are they identical to other utilities.

FlexNet provides you with advanced metering data and demand side management capabilities. You set the parameters – **the system responds.**

What's more, this intelligent system is available in custom packages for electricity, gas and water utilities with all meters supported on the same network. That's flexibility. **That's FlexNet.**

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Grant Gilchrist, P. Eng.

The Next Generation of Substation Builders

By: Grant Gilchrist, P. Eng. & Ron Farquharson, EnerNex Corporation

Ron Farquharson

While the IEC 61850 substation communications standard has arrived in Europe and parts of the rest of the world as an "instant hit," acceptance in North America has been more lukewarm. Early adopter utilities, some of whom have only recently changed over to "second generation" communications protocols such as DNP3, are concerned about the complexity and associated cost of deploying the next big step.

The truth is that IEC 61850 has the potential to significantly reduce the costs of planning, configuring and later upgrading a substation automation system. Papers have shown that using the IEC 61850 Part 6 Substation Configuration Language (SCL) standard file format and the self-description capability of the protocol can reduce the time required to set up a substation device - say, a protection relay- by 75% or more.

However, the key to achieving such benefits is the availability of tools that take advantage of these features of IEC 61850. So far, not many have done so.

CURRENT TOOLS TAKE THE FIRST STEPS

Development of IEC 61850 products has followed a fairly straightforward pattern. The first IEC 61850 devices to appear were fixed-function or specialized function devices, particularly protection relays and meters.

The first configuration tools to be developed therefore only had to select a few options to build a complete IEC 61850 object model. The user could choose, for instance, which protection elements to enable, and the configuration tool would use those few decisions to automatically build the complete set of IEC 61850 data the device would produce – hundreds or thousands of points of information. Or, more often, the IEC 61850 view of the device would be fixed, with no options at all. The sole purpose of the tool was to configure this one type of device.

Such an approach works fine for a specialized Intelligent Electronic Device (IED), but not so well for those devices that have to be more flexible. Devices such as substation user interfaces, data concentrators, protocol converters, substation computers, and logic controllers have to act as IEC 61850 clients, gathering data from dozens or even hundreds of Intelligent Electronic Devices (IEDs). They must read the data and map it to their internal databases; they may display the data or process it before passing it on. These clients need a view of all the data in the substation.

And IEC 61850 IEDs in the substation vary widely, just like their predecessors, and perhaps even more so. While IEC 61850 standardizes how data should be named and structured, the specification permits great variation in what data is actually reported by any device. Vendors are permitted to add or remove items as necessary to provide added value. This makes it more difficult to configure a client and a substation.

Perhaps, for this reason, there have so far been few IEC 61850 clients available, and correspondingly few system-level substation configuration tools for IEC 61850. The specification is well-suited for creating such tools; the standard SCL file format permits tools to store information about the electrical connectivity, communications network, number and type of devices, and of course the data reported by all the devices in the substation.

Nevertheless, most tools available configure only single devices or just those from that vendor. Those that do attempt to interconnect multiple devices tend to focus on a particular aspect of the protocol. For instance, high-speed peer-to-peer protection messaging, named Generic Object-Oriented Substation Events, or GOOSE, is a popular feature of IEC 61850. Therefore, some vendors have tools that permit the configuration of the GOOSE protocol between multiple devices. However, these tools do not configure any of the other IEC 61850 features.

Other tools have a different problem: they provide a system level view of the substation, but are intended to be planning tools and require a significant knowledge of IEC 61850. The language they use is the language of the protocol,

not the power system engineer. For instance, the text string "MMXU3.PhV.phsA.cVal.mag.f" translates to "Magnitude expressed in floating-point format of the Phase-to-Ground Volts on Phase A, gathered by the Metering Measurement Unit connected to feeder 3." However, a power engineer setting up a substation using the new tools for the first time cannot be expected to know that. It is a major breakthrough of IEC 61850 that the protocol can standardize and express such names, but tools need to speak the language of their primary users.

Even better, tools should speak graphically, not with text at all. Substation Configuration Language has the capability to represent simple substation one-line diagrams. Very few IEC 61850 tools yet make use of this powerful feature as a method for actually planning the substation, from the electrical equipment to the communications equipment down to the functions and thousands of data points.

The IEC 61850 tools that are available now are good at what they do – mostly configuring individual devices. However, they are missing much of the potential of IEC 61850.

BARRIERS TO EVOLUTION

So why have system-level configuration tools been slow to appear? One reason is that it is simply a lot of work. Like the window-based desktop used by today's computers, IEC 61850 has the capability to "hide" the complexity of computing systems from the user and turn that complexity into a "point-and-click" experience. However, just like the Windows-based desktop, a significant amount of software must be written by the vendors in order to make that experience happen. As with desktop computing, complexity has been shifted away from the user and onto the developer.

IEC 61850 vendors have sensibly (and cost-effectively) chosen to break the problem into smaller products that can be released individually, rather than the "moon shot" approach of trying to do everything at once. For most, this means developing a single-device configuration tool, and then using it as a platform to build a system tool.

One major barrier to this evolution is the vendors' installed product bases, which are mostly built around unstructured, points-list types of databases. Mapping structured IEC 61850 data models into this format without a lot of human intervention is a formidable task.

Another barrier is the fact that many IED vendors are not GUI developers. They are experts at high-performance, real-time embedded software and need to develop the capability to write sophisticated GUI software. Some have begun to do this through partnerships, others by buying the software. The larger vendors have managed this by leveraging expertise found in other divisions of their organization. Any of these efforts take more time. The first fruits of this "ramp-up" in GUI technology are only beginning to be seen.

WHAT WILL THE KILLER APP LOOK LIKE?

In spite of the these barriers, we do not want to lose sight of our clear goal as an industry; a real top down design approach. In addition to supporting the IED centric configuration approach, the IEC 61850 Part 6 Standard has been written to support the top down approach starting with definition of the complete substation and power system functions. The starting point for configuration would be the station one-line with device ratings and power system functions

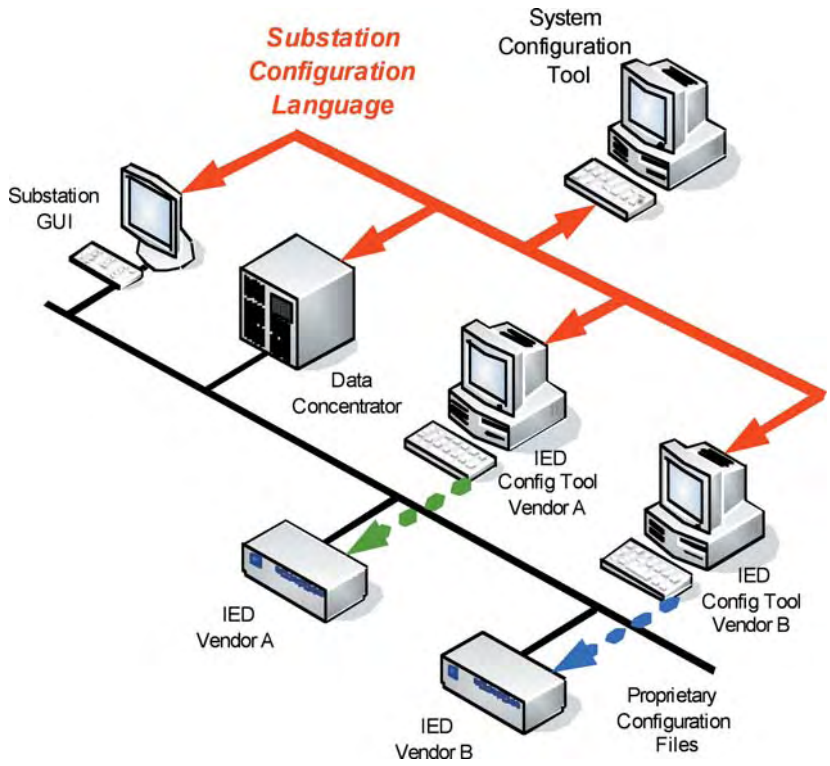

Figure 1 *Example of System-Level Substation Configuration*

followed by a definition of the associated automation functions. The potential system wide benefits for such a capability are very significant – in fact huge!

What utilities need to convince them of the usefulness of IEC 61850 is a tool that looks at the entire substation. Figure 1 illustrates how such a tool might be used. It would have the following characteristics:

- **Start with the users.** Developers of successful PC software have learned that writing use cases, holding workshops, utilizing focus groups, taking surveys and other such requirements-gathering processes pay off. Just because the target user is an engineer is no excuse for making it hard to use.

- **Design from the top down.** A system level configuration tool that follows a progression starting with the definition of the complete substation, including the power system and protection functions, and adding the desired communications and automation functions will enable engineers to select the IEDs with the needed capabilities. This will help avoid the "take a shopping cart to the trade show" method of designing a substation. IEC 61850 is the first paradigm that permits users to choose functions first, rather than devices.

- **Design the whole substation.** Such a tool must not focus on a single device, but permit an engineer to start with a one-line diagram for the substation, add functions, and then map those functions to devices. To continue the progression stated above, the System Level (Substation) Configuration Tool of the future should allow the engineer to acquire the IED Capability Description (ICD) files from the new IEDs, drag-n-drop the functions they have already defined onto the IEDs, and then generate a Configured IED Description (CID) file that the IED level configuration tool would use.

- **Design the whole protocol.** IEC 61850's potential will not be realized through only one feature or set of features. Having multiple smaller tools that configure different aspects of the protocol is a valid design methodology, but to be easy to use, they must work together.

- **Work seamlessly with other tools.** Figure 1 shows how SCL is intended to serve as a common language for either transferring data between tools, or for transferring configurations directly with devices such as the data concentrator and GUI in the figure. At the moment, there is no standard transport mechanism or service interface defined for exchanging SCL files. System tools must therefore take the initiative to launch other vendors' tools or to select custom directories where SCL files could be placed.

- **Use human language.** As discussed earlier in this article, IEC 61850 names, while standardized, are not easy to use.

- **Use current GUI technology.** The power industry is a small market, and therefore vendors do not have the same resources the desktop computing industry has for designing user-friendly software. However, that doesn't mean that power industry software has to look like freeware. A key feature often mentioned wistfully by users is the ability to create "templates" of IEDs that can be dragged onto a working area and then customized. Not all configuration tools support this rather basic capability.

Engineers involved in the development of IEC 61850 have been talking about this kind of tool for nearly a decade now, but the potential users of the standard have not been informed about how it could work.

THE FUTURE OF IEC 61850 RIDES ON EASE OF USE

It is instructive to observe the different approaches to substation automation taken in different parts of the world and the impacts on the adoption of new technologies such as IEC 61850. The lessons learned from this highlight the importance of investing in the next generation of user configuration tools.

In Europe and some international regions, there is a strong practice of following IEC standards. A significant amount of automation equipment is purchased as a component of a complete substation project procured from one vendor or substation integration contractor. This means that even though the protection and control devices support 61850, the difficulty in integrating the devices is mitigated. When these stations are expanded or upgraded the tendency is to go back to the original equipment provider.

In North America our view of standards in the communication protocol area is less rigorous and we prefer to be less reliant on our suppliers. While things have begun to change in the last few years, historically the support of a standard communication protocol was not a key determinant in the selection of a specific IED. This led to a proliferation of devices supporting different protocols. In addition the majority of protection equipment is purchased separately from the control equipment and installed on a retrofit basis. This has led to products from many vendors speaking a number of protocols in most substations. This has a number of significant impacts on the application of IEC 61850 in North America:

- Easy to use configuration tools for IEDs are essential
- IED Data Concentrators or Gateways supporting IEC 61850 Client & Server implementations are needed to connect the legacy IEDs onto the Substation Network (Station LAN).
- Strong focus on the development of easy to use configuration tools is needed for the IED Data Concentrators.
- Efforts to define common methods and tools between 61850 and popular current protocols such as DNP are important (see "Next Stage" section).

The effort to develop these tools will be well rewarded. Utilities implementing IEC 61850 are already seeing substantial benefits depending on the size and architecture of the system. Yet there remain larger potential benefits inherent with the protocol, object oriented and Ethernet LAN approaches as well as engineering process and SCL incorporated into IEC 61850. Some of these benefits include reductions in:

- Initial engineering and design
- Ease of configuration
- Installation/wiring and testing
- Commissioning
- Effort for future upgrades
- Staff training

As mentioned above, savings in the device configuration area alone can approach 75 percent compared to the current effort with other protocols. In addition, the use of substation level configuration tools can bring further reductions in the other areas listed above – notably engineering, testing and commissioning. In combining these reductions, we should expect substantially lower life cycle costs of this protection and control equipment as we go forward. This is very possible as the capital cost of the equipment is typically less than 20 percent of the total installed cost with the other 80 percent coming from the scope where potential savings are large. Long term operations and maintenance savings and improvement in system reliability add to this overall benefit.

THE NEXT STAGE

Once more system-level IEC 61850 configuration tools are available, there are further steps that could be taken to integrate these substation tools with the rest of the power system.

Firstly, other protocols are developing standard configuration formats of their own. Chief among these is DNP3, which has more users than any other protocol among electrical utilities in North America. The DNP Users' Group will soon be releasing a configuration file format

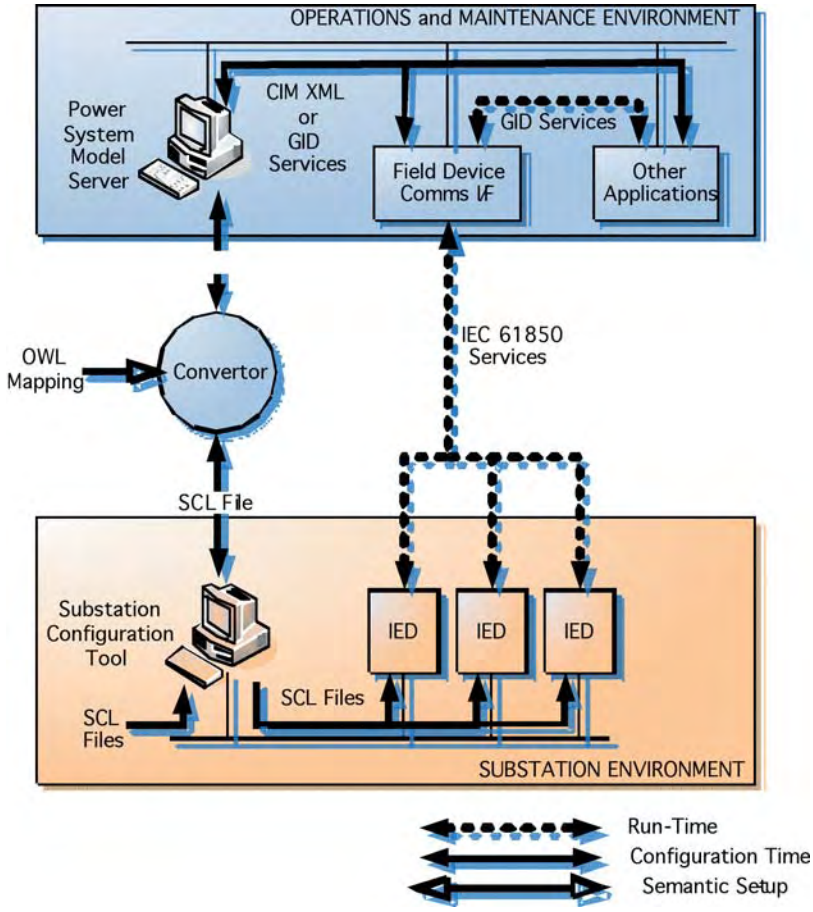

Figure 2 Possible Method of Linking IEC 61850 and CIM/GID. © EPRI 2006, used with permission

that mirrors the paper Device Profile Document previously used to describe DNP device implementations. Although not as flexible as SCL, the current draft of this XML schema contains locations where IEC 61850 data attribute names could be stored. A system configuration tool that could make use of such links would speed up the creation of DNP3-to-IEC 61850 gateways. This would not only reduce the costs of substation integration, but would also help accelerate the acceptance of IEC 61850 in North America.

Secondly, there is a whole world of data communications in progress within the control center or "power system operations and maintenance" environment that has only just begun to reach out toward the substation. IEC working groups have begun to define how to harmonize the IEC 61850 standard with the IEC 61970 Common Information Model (CIM) and Generic Interface Definition (GID) specifications. Figure 2 illustrates one proposal for how this might occur using Web Ontology Language (OWL) to enable converters between SCL and CIM XML formats.

Such a harmonization between substation and control center environments might enable system-wide applications such as:

- Wide-area protection algorithms
- System-wide live testing of protection schemes
- Creation of micro-grids and intentional islanding
- Integration of distributed generation
- More accurate state estimation through synchrophasor collection
- Distribution of metering data throughout the utility

In this way, the next generation of IEC 61850 configuration tools may lead to something even bigger: the ability to build not just complete substations, but an intelligent power grid. ■

About the Authors

***Grant Gilchrist**, P.ENG. is a consulting engineer for EnerNex Corporation and a recognized expert in data communications for the electric power industry, particularly in areas relating to Internet protocols, OSI, security, and SCADA applications. He has been extensively involved in standards development for the IEC, IEEE, American Gas Association, Standards Council of Canada, and the DNP Technical Committee. Gilchrist was a key contributor to the EPRI IntelliGrid Architecture and Utility Communications Architecture. He has been actively involved in the development of the IEC 61850 series of utility communications standards, and a key contributor to the rollout and deployment of IEC 60870-5 protocols.*

***Ron Farquharson** is a consultant in utility automation for EnerNex Corporation. He has over 25 years experience in substation control, automation, and monitoring. Farquharson spent the bulk of his career at GE/GE Harris/Harris/Westronic, where he held numerous positions in product management/ marketing and project management. He chaired the Task Force in the IEEE PES Substations Committee called "The Use of Computer Technology in Substation Data Acquisition and Control." He was also a key driver behind the DNP protocol development at Westronic and the decision to form the DNP User Group. He currently serves on the DistribuTECH Conference Advisory Committee.*

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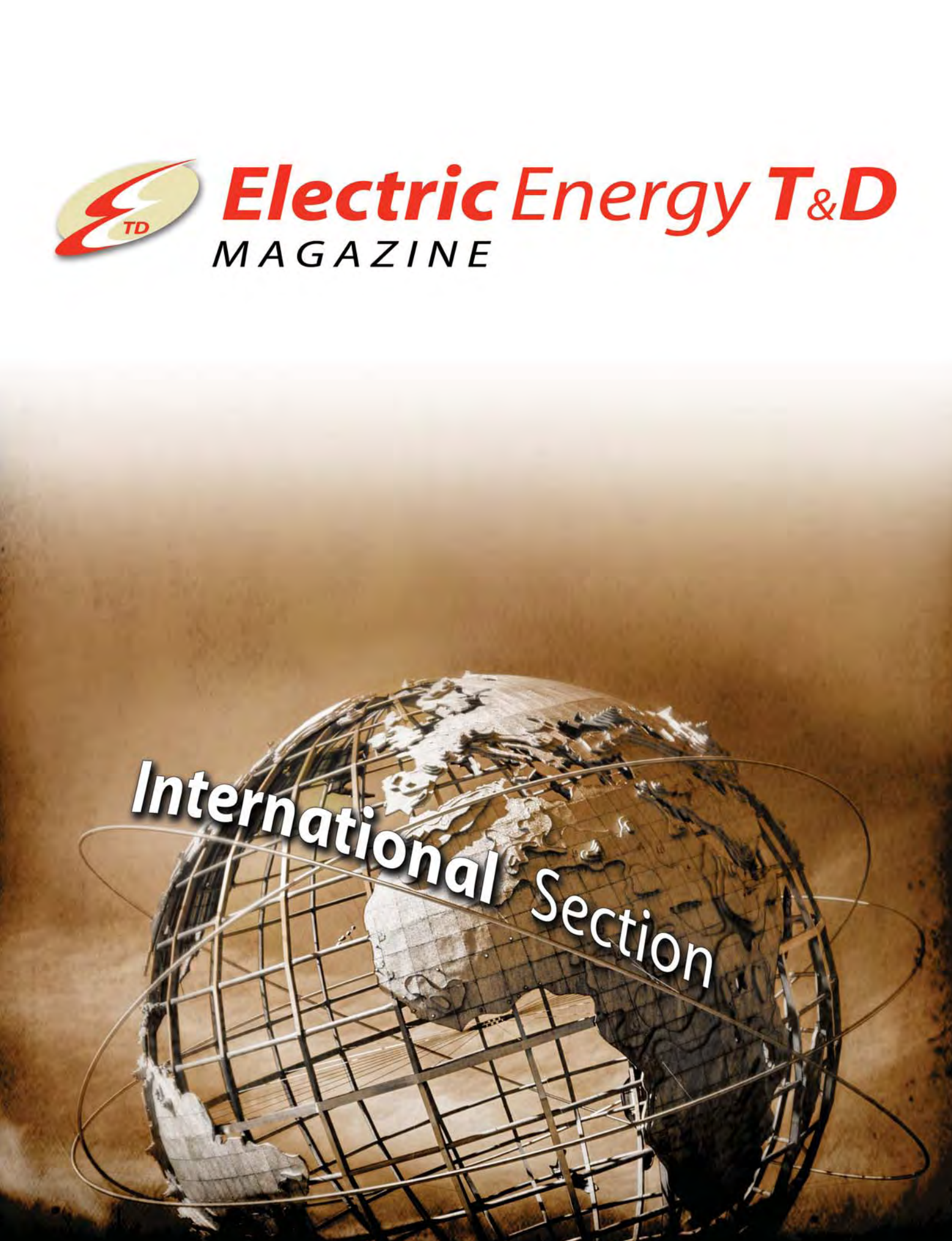

HVDC on the High Seas

By: Bob Fesmire, ABB Inc.

Recently, BP announced it would undertake a major redevelopment project at its Valhall facility in the North Sea. As part of the project, the company will do away with its on-site generation and instead get all of the power needed to run the multi-platform complex from shore via undersea cable. Valhall is the second oil platform to opt for power from shore (PFS), the first being Statoil's Troll A installation, and it will be the first to rely entirely on PFS to power all of the facility's operations.

The technology used to deliver electric power to Troll A and Valhall is a form of high voltage direct current (HVDC) based on voltage source converters (VSC). Developed by ABB and dubbed HVDC Light®, this technology is uniquely suited for PFS applications, and also could be a key enabler in the development of deep water wind farms. So what makes HVDC Light different from traditional HVDC? To answer that, some history is in order.

A (VERY) BRIEF HISTORY OF HVDC

Development of HVDC transmission began in the 1920's, but it wasn't until 1954 when the world's first commercial installation of the technology was energized—a 20 MW, 100 kV line linking Sweden's Gotland Island with the mainland. Since that time, HVDC has been utilized primarily to transport large amounts of power over long distances, typically via undersea cables, but also with aerial lines such as the Pacific DC Intertie on the US West Coast.

The economics of HVDC drove the trend towards long lines. HVDC converter stations are expensive relative to AC systems, but the per-mile costs for HVDC lines themselves are low. Three-phase AC requires three conductors to HVDC's two. Line losses are also lower with HVDC—as much as 50% lower than comparable AC facilities. So, for the better part of fifty years, HVDC has been great for long haul transmission, but has remained economically impractical for shorter distances.

THE NEXT GENERATION: HVDC LIGHT

That conventional wisdom began to change in the 1990's with the development of HVDC Light technology that takes advantage of modern transistors in place of the thyristors used in conventional HVDC. The first commercial application of it was fittingly located once again on Gotland island in 1999.

Interestingly, the Gotland project was undertaken to connect a remotely located wind farm to the island's AC grid for the purpose of exporting wind power back to the mainland in addition to supplying local loads. Presently it is the only application of HVDC Light in a wind context, but offshore wind farms could become an important user of the technology.

Some of what makes HVDC Light so useful for offshore applications derives from how it differs from conventional HVDC facilities. The cables, for example, are smaller, lighter and more flexible than traditional HVDC cables. They utilize a polymer insulation layer instead of oil, so there is no fluid to leak should the cable ever be punctured. This means that the cables are well suited to both undersea and underground use, and pose a much smaller environmental risk. Like conventional HVDC, they also emit almost no electromagnetic field.

The VSC converters are also small and lightweight. This fact is of particular importance in the case of offshore platforms where space and weight are at a premium. In fact, the weight of the Valhall facility has compacted the sea floor over the years to the point where the ocean is actually 15 feet deeper now than when the installation was constructed. That is partly why the housing and compression platforms will be replaced in the revamping project.

Differences in the cables and converters

between HVDC and HVDC Light, however, pale in comparison to the differences between on-site generation and the PFS alternative made possible by HVDC Light. With regard to the space/weight challenge, power from shore means the platform doesn't need to have a large generator, or a fuel tank to feed it. This also implies greater safety and lower environmental risk when you consider the elimination of the potential for fuel spills or gas leaks. And there is of course an economic dimension here—aside from saving on fuel costs, gas collected in a platform's operations that is then used to operate on-site turbines can instead be returned to the company's revenue stream if power is delivered from shore.

Operations and maintenance costs, long-term reliability, safety and environmental concerns, overall economics—these factors make for a compelling business case for PFS, and indeed they played a role in both the Troll A and Valhall projects. Environmental concerns have a very specific economic impact on the Norwegian Shelf where Norway's tax on emissions is imposed. The Valhall project will allow BP to avoid the release of 300,000 tons of CO2 and 250 tons of NOx per year from the platform site. The power delivered from shore will come from Norway's grid, which is in turn supplied overwhelmingly by emission-free hydro power, so the emissions reductions at sea are not being negated by increases from fossil fueled plants on shore.

OFFSHORE WIND

The North Sea is of course home to another vast energy source: wind. There has been a lot of talk and a good deal of action over the past several years in the development of offshore wind power facilities, but all of the projects to date have been located relatively close to shore. Wind resources tend to improve the farther away from land the turbines are located so it's easy to see why wind developers have been eyeing deepwater installations with higher towers and multi-megawatt turbines. The European "Supergrid" concept is one example of this thinking.

In such locations (hundreds of miles from land), AC transmission simply isn't practical due to the need for voltage support along the way back to shore. HVDC would appear to fit the bill—large amounts of power sent over long distances—but there are other mitigating factors. For example, the most geographically convenient point of interconnection on land for offshore wind farms is usually not ideal from a power engineering perspective. However, HVDC Light does not rely on the AC network's ability to keep the voltage and frequency stable. Unlike conventional HVDC, the short circuit capacity is not important.

HVDC Light offers a much greater degree of control over active and reactive power, and allows the two to be controlled independent of one another. It can also operate at very low power, even zero power, versus the typical 5% power minimum for conventional HVDC. This and the ability to quickly reverse the direction of power flow become important in the event of a grid failure onshore when auxiliary power is needed at the platform site. All of these factors contribute to a stronger, more reliable interconnection for wind power.

In the context of offshore applications, HVDC Light is an enabling technology that produces a variety of direct and indirect benefits. The convergence of economic and environmental priorities, as presented in the PFS projects noted above as well as offshore wind development, appear likely to drive further use of HVDC Light into the future. ■

About the Author

Bob Fesmire *is a communications manager with ABB's Power Products and Power Systems divisions. He writes regularly on transmission and distribution, IT systems and other industry topics. He can be contacted at bob.fesmire@us.abb.com.*

KEY FACTS ON TROLL A AND VALHALL FACILITIES

VALHALL
Commissioning year: 2009
Power rating: 78 MW
No of circuits: 1
AC Voltage: 300 kV (Lista), 11 kV (Valhall)
DC Voltage: 150 kV
Length of DC submarine cable: 292 km

Main reason for choosing HVDC Light: Reduce costs and improve operation efficiency of the field. Minimize emission of green house gases.

Note: First offshore platform to be powered entirely by power from shore

TROLL A
Commissioning year: 2005
Power rating: 84 MW
No of circuits 2
AC Voltage: 132 kV (Kollsnes), 56 kV (Troll)
DC Voltage: ±60 kV
Length of DC submarine cables: 4 x 70 km

Main reason for choosing HVDC Light: Environment, long submarine cable distance, compactness of converter on platform

Note: PFS used to power platform's compressors using a direct connection

The Future of AMR/AMI in the United Arab Emirates

By: Ali Mouslmani, Regional Director for Elster Group, Middle East and North Africa

A trip to Dubai takes visitors on a journey through time. There is not a lot of documentation on the early history of Dubai. Nevertheless, archeological discoveries suggest that, small fishing communities lived along the coast of the Arabian Gulf as far back as four thousand years ago. Some historians believe that the natural sheltered harbor created by the Dubai Creek was a busy port on the ancient trade route between Mesopotamia and the Indus Valley. In recent years, archeologists have discovered many artifacts, including pottery, weapons and coinage, which point to civilized settlements dating back to the third millennium B.C.

Modern Dubai traces its origins to the 1830's. About 800 members of the Bani Yas tribe, led by the Maktoum family, settled at the mouth of the Dubai creek in 1833 and soon the harbor became a center for the fishing, pearling and sea trade. The Maktoum family still rules the emirate today. By the turn of the 20th century, Dubai was a successful seaport. The souk (Arabic for market) on the Deira side of the Dubai creek was the largest on the coast with 350 shops and a steady flow of visitors and businessmen. By the 1930s Dubai's population was nearly 20,000, a quarter of who were expatriates. When oil was discovered in 1966, the late Ruler of Dubai, His Highness Sheikh Rashid bin Saeed Al Maktoum utilized the oil revenues to spur infrastructure development in Dubai by building schools, hospitals, roads, a modern telecommunications network. By the mid 20th century, the pace of development was growing very fast.

Over the last three decades, Dubai has grown dramatically. It has become a major business hub that supports a dynamic and diversified economy. Dubai's strategic location allows it to serve as the largest re-exporting center in the Middle East. Its low logistical and operational costs and excellent infrastructure, international outlook and liberal government policies are attracting major investors from all over the world. Trade, transport, tourism, industry and finance have all seen steady growth and have helped the economy to expand and diversify.

UAE'S UTILITIES

There are four utilities that provide power and water to residents of the UAE. The Federal Electricity and Water Authority (FEWA), Sharja Water and Electricity Authority (SEWA), Abu Dhabi Electricity and Water Authority (ADWEA) and Dubai Electricity and Water Authority (DEWA).

UAE utilities embrace a philosophy of constant planning and forecasting to meet the growing demand of their customers. This philosophy has been a major driver for the UAE Authorities. They are focused on serving their customers and contributing to the economic growth of the UAE by meeting the growing demand for power and water resulting from new large scale and exclusive real estate developments in the area. They also understand how modern metering automation will allow them to continue to improve their business operations, customer satisfaction, and profitability. Modernizing is a top priority for DEWA, FEWA and ADWAEA and they have a commitment to make the Authority more open and accessible to the public. The vision is to build services around the needs and expectations of citizens, residents and businesses.

THE STATE OF AMR/AMI IN THE UAE TODAY

Walk/by and drive/by one-way AMR solutions may not be the optimum solution for meter reading and control automation because of the high traffic and congestion created by business and tourism through much of the area. There are also several exclusive neighborhoods that are large scale and have limited access.

Most utilities in the gulf region have not rolled out any AMR or AMI system of any significant size. There are several ongoing pilot projects using approximately 100 meters. These projects consist of meters that are read using power line carrier (PLC). Nevertheless, PLC has not proven itself to be a viable solution for the gulf region. There are issues with PLC on both reliability and capability. PLC does not have sufficient speed or the bandwidth needed to handle multiple metering functions. Utilities are not satisfied with the pilots using PLC technology, and they are still looking for a cost-effective solution that has the flexibility to enable them to access meter information more easily and reduce meter reading losses that are attributable to human error.

BUSINESS CASE DRIVERS FOR AMR/AMI IN THE UAE

There are many regional differences that drive AMR/AMI in this market. Many utilities around the world build a business case based on such things as improving business operations, lowering costs, automating the meter reading process and improving customer service. In the gulf region, the business case for AMR or AMI is based on both business and on cultural issues. For example, most of the meters in the gulf region are outdoors, but some of the older buildings have meters indoors. Meter readers often cannot read indoor meters at residences where the head of the household is not present. This creates a challenging situation for meter readers who need access to indoor meters and may result in repetitive visits to read the meters.

Five to six months of the year the region's weather is very hot and it becomes undesirable to work outdoors. From April to October daily average temperatures range from 86 to 103 degrees Fahrenheit. In June through September the average temperature is around 100 to 103

degrees Fahrenheit. During these times of year, the meter reader's efficiency may be greatly reduced. Two issues may arise from the heat during the summer in Dubai; meter readers tend to read less meters, and are susceptible to making errors. Most meter readers do not have handheld devices for reading the meter. They manually read the meters and record the meter readings in a log. This creates two instances where the potential of making an error exists. The first instance is when the meter is read and the information is written down. The second instance is when the meter reading is manually entered into the billing system. Additionally, there may not be enough manpower to read meters every month, so they may read the meters every other month, and estimate the month in between readings. Estimated bills tend to be a customer service issue because there may be some hardship for customers to pay in months where the bill is estimated. Estimated bills can be significantly higher or lower from month to month when it is very hot. Like utility customers in the US and other parts of the world, UAE consumers prefer actual meter reads every month.

THE CHALLENGES TO AMR/AMI IN THE UAE

Although residential and commercial buildings have mapped addresses, all mail is delivered to post office boxes at the post office. This creates issues for the electrical utility and consumers in several ways. A person must go to the post office to retrieve their mail, instead of just walking outside to retrieve their mail from a mailbox. Typically bills are not paid by check in the region. People tend to stand in line to pay their utility bills at a location that takes payments for the utility. Some utilities, such as DEWA, do offer limited online services to customers that sign up for it so they can view and pay their monthly bill. Nevertheless, these services are based on bills generated from manual reads or estimated bills. It would be more efficient for them to have an automated system that allows them to collect monthly billing data, process it, and display an accurate bill in a manner the customer finds useful. This could be through the internet, email, in home device, or some other means.

Most of the new residential properties that have the meter installed outside the home also have the meter installed inside a meter box on a gate or pedestal. Obviously, it becomes very hot inside the meter boxes during the summer months. In the gulf region, high humidity adds to the heat problem. Because of this, most of the residential meters that are still purchased for use in the region are electromechanical meters. Many of the commercial and industrial meters are electronic because they are usually located inside the building, and though they may not be in an air conditioned environment, they are in a location that is not in the same heat and humidity as outside. Residential electronic meters must prove to be robust enough to handle the harsh summer climate in the Middle East, year after year.

CUSTOMER SERVICE IS MORE THAN AUTOMATED METER READING

Utilities in the region prefer to deploy the latest technology available. When it comes to technology, they like to consider themselves cutting edge users of it. But they expect cutting edge technology to work. They do not want to have to work out unexpected flaws in the technology they select; they expect the technology to work right out of the box. Consequently, when they consider using AMR or AMI, they require technology that allows them to do more than just automatically read a meter once a month for billing.

One of the common features of smart meters in an advanced metering infrastructure is the ability to remotely connect and disconnect meters. This feature of metering automation is very important in areas like Dubai. By law in Dubai, when a customer pays their bill after service has been disconnected; the utility company must restore power to customer within 30 minutes.

Having the ability to read voltage at the meter is an advantage for utilities in the region for the same reasons it is in the US. Forty percent of the time, service calls result in utility trucks rolling when it is not the problem of the utility, but rather a problem at the customer's end. If a utility can remotely read the voltage at the meter, problems can be diagnosed and unnecessary trips to the field for service calls can be eliminated.

In some countries in the region there is a significant low-income population, and utilities have seen problems with non-payment. Some utilities in the area need solutions that enable them to handle prepayment for low-income areas. So far, the cost of installing prepay meters and equipment in low income areas has been too expensive. Existing solutions available in the region are not proving to be viable. So ultimately, utilities are looking for improved asset management tools that enable them to better serve lower income families. When customers know that the utility company can connect and disconnect from a remote location, it encourages customers to make payments on time. For areas where people frequently move in and move out, having the ability to remotely connect and disconnect service is a big advantage to utilities.

MEETING THE NEEDS

Dubai, Qatar and the surrounding areas of the Middle East and Africa continue to be an area of opportunity for utilities to introduce AMR and AMI solutions. So far, no one has delivered a solution that can meet and adapt to the needs of utilities in this region of the world. These utility companies need remote metering automation systems with features that enable them to offer flexible and more frequent payment plans, such as weekly payment plans, and the ability to remotely connect and disconnect meters. Understanding the technology needed is key for any company positioning themselves to move into areas such as the Persian and Arabian Gulf region and other areas of the Middle East and Africa. ■

About the Author

Ali Mouslmani *is the Regional Director for Elster Group in Dubai and serves the Middle East and Africa. Ali holds a Bachelor of Science degree in Electrical Engineer from Northeastern University, Boston Massachusetts. Mouslmani has been responsible for developing the electricity metering business in the Middle East and Africa for both ABB and Elster Electricity Metering since 1996. With over 10 years experience in the electricity metering business, Mouslmani has successfully lead several projects for industrial automated meter reading systems in the Middle East and Africa. Prior to his current position with Elster, he spent three years working with ABB relay protection systems.*
email: ali.mouslmani@ae.elster.com

Evolving to a Strategic Substation Network Architecture

By: John M. Shaw, EVP of GarrettCom, Inc.

Substation network planners are challenged to: integrate SCADA system connections, remote engineering access and other networking requirements for substations; do it now with minimal cost, and make sure the solution will evolve gracefully for many years across emerging requirements for scale, technology, security, performance, and manageability.

Planners must find the balance between near-term imperatives and longer-term vision. They may have a clear target architecture, but rarely do they get to put it into place all at once. In practice, the architecture unfolds one incremental project after another. To ensure an orderly network evolution, planners must shape each tactical deployment step to be consistent with a clearly defined set of strategic objectives.

OVERARCHING SUBSTATION NETWORK DESIGN FACTORS

Among the many factors influencing network architecture, the four that are most prominent are:

- Network Integration
  This involves consolidation of network connections onto a common infrastructure in order to reduce network costs, provide increased remote access to substation devices, and facilitate implementation of additional substation automation applications.

- Cyber Security
  Generically, this involves meeting best practices for managing the risk of cyber attacks on internal systems and grid operations. However, the current emphasis of cyber-security-related projects is on compliance with recent industry standards related to Critical Infrastructure Protection (CIP).

- Reliability
  High network reliability is a growing concern as SCADA (Supervisory Control and Data Acquisition) and other operational systems play an increasingly critical role in grid operations. Also, as substations networks become more advanced and integrated, single network outages can affect a larger number of systems and control elements.

- Overall Cost Effectiveness
  While the other strategic objectives all play a role in cost effectiveness, planners must manage not only initial costs, but also ongoing operations, telecommunications and maintenance expense, as well as longer-term life cycle costs such as premature network obsolescence due to feature or scalability limitations.

Effective planning requires both an integrated architectural vision that addresses these objectives, and a flexible set of tactical steps that allow projects to move incrementally forward on an opportunistic basis.

NETWORK INTEGRATION

Ethernet and Internet Protocol (IP) have emerged as the unifying technologies for substation data networking. Both IEC 61850 and the related Utility Communications Architecture (UCA2) envision Ethernet as the universal connectivity medium for substation communications. The widespread adoption of Ethernet by vendors has driven down costs and provided a consistent technology across diverse systems. Ethernet provides the high-performance and prioritization features needed to combine multiple applications on a single network medium, as well as to support resilient topologies and software-controlled rerouting for network reliability. On a more end-to-end systems basis, Internet Protocol (IP) works over Ethernet to provide a flexible and widely accepted protocol framework for communications among intelligent devices and application servers.

As described below, Ethernet switches are available either in many stand-alone configurations or as components of hybrid, multi-function devices, giving planners considerable flexibility to build out Ethernet-based infrastructure incrementally over time. The largest obstacle to Ethernet-based network integration is not Ethernet, per se, but rather the large number of existing non-Ethernet-based substation devices, including some newly deployed devices, since substation technology changes slowly. Also, planners must consider a still-evolving set of technology options for interconnecting substations and control centers over Wide Area Networks (WANs).

Integration of serial protocol substation devices onto an Ethernet infrastructure is a major challenge. There are a number of devices called Terminal Servers, Serial Device Servers or Console Servers (all essentially the same thing). These devices encapsulate short serial data messages into TCP/IP packets (Transmission Control Protocol over IP) to send over Ethernet, and each serial stream is associated with a unique TCP/IP session. Terminal Servers may also be used at the host/master location to convert Serial-IP streams back to serial format. Alternatively, some master servers or remote PCs may interface directly to Serial-IP streams over IP/Ethernet connections. A newer generation of Serial-IP devices called Serial Device Routers may be deployed on a distributed basis in substations, creating a Dynamic Serial Edge for the substation network. This concept is described further in the context of security and reliability.

Performance over Wide Area Networks (WANs) can be an issue with Serial-IP network integration because of limited bandwidth, e.g., 56 kbps or fractional-T1 (less than 1.5 Mbps) frame relay or dedicated digital services.

Many SCADA hosts that use Serial remote devices have short polling intervals; unless they receive a response from a remote IED in less than 100 milliseconds, they may assume a network problem. Some Serial-IP networks cannot consistently achieve this low latency. One element that affects network latency can be the protocol overhead of TCP/IP encapsulation. As shown in Figure 1, serial SCADA messages may be only a few bytes long, but TCP/IP protocol headers increase the length of the Serial-IP packets by an order of magnitude. This can be remedied with a technique called SCADA Frame Forwarding that uses frame-relay-based encapsulation with only a few bytes of header to multiplex serial SCADA traffic on a WAN network. SCADA Frame Forwarding coexists on the WAN with IP-based traffic. SCADA Frame Forwarding includes fragmentation and prioritization features that, together with efficient traffic encapsulation, ensure that critical SCADA traffic has the high performance and preemptive prioritization needed to meet latency requirements.

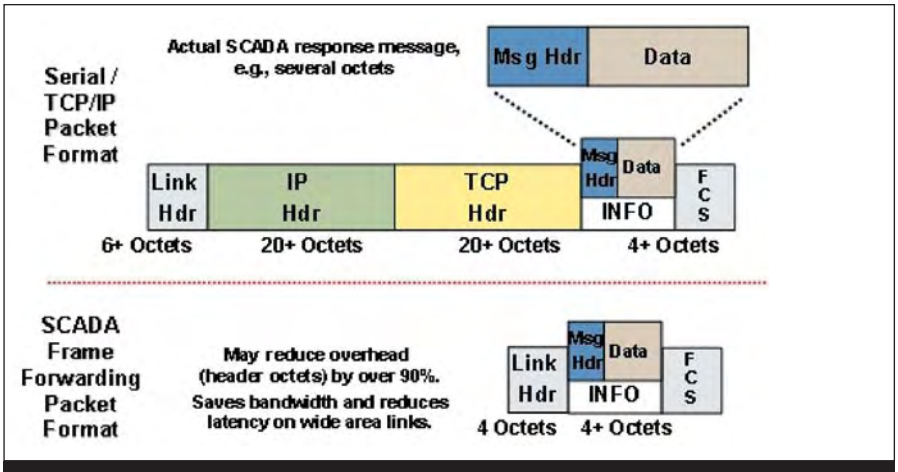

Figure 1: Serial-IP Protocol Overhead vs. SCADA Frame Forwarding

It is important that WAN interface devices deployed in the near term, including those using SCADA Frame Forwarding, be compatible with longer-term WAN interface requirements for higher bandwidth and new protocols such as MPLS (Multi-Protocol Label Switching) and DiffServ. Over time, WANs will increasingly move to broadband speeds, whether using utilities' private fiber facilities or broadband services offered by carriers. Major carriers have introduced private IP services based on MPLS and have positioned these services to gradually displace other digital services such as frame relay and dedicated digital leased lines. IP/MPLS services should have greater bandwidth to help resolve most latency issues, but will still require traffic prioritization for critical applications. DiffServ, a specification for marking and treating IP packets such that all the routers in the network path can recognize and provide appropriate prioritization, must be used to prioritize critical data, such as SCADA, when utilizing MPLS services.

CYBER SECURITY

The immediate drivers for implementation of cyber security measures in substations are the NERC Critical Infrastructure Protection standards, CIP-002 to CIP-009. These describe a number of new requirements for secure management of network devices that will now be factors in product selection. In terms of substation network architecture, the dominant concern, as defined in CIP-005, is creation of an Electronic Security Perimeter. In particular, this requires implementation of an IP-based firewall at the network boundary between the substation and the external WAN environment. The key roles of the firewall are filtering of IP addresses and TCP and UDP port numbers and forwarding traffic only for appropriate, authorized combinations of source and destination addresses/ports. The firewall function can be implemented as a stand-alone security appliance, but is usually integrated with an IP router at the boundary of a substation. For some utilities, CIP compliance will require deployment of a new network router/firewall device, but in other cases existing network routers will support an IP firewall as an incremental software feature.

Another key CIP requirement is port access security. This includes assuring that ports "nailed up" to IEDs are in fact associated only with those IEDs, and that inactive ports remain inactive. Port access security also requires rigorous access authentication and authorization schemes for ports associated with intermittent, on-demand applications (e.g., console ports shared by various remote engineers and administrators). While initially only a few ports on a few devices may be involved, over time reliability, efficiency and scalability strategies will require more ports, more devices and wider distribution of the devices within the substation. These requirements call for a consistent, structured approach to port security.

Ethernet port security should involve three main technologies. VLANs (802.1Q Virtual LANs) provide closed communities of interest among Ethernet ports, even distributed over several switches. MAC-level port security enables Ethernet switches to learn a unique MAC address for a specific IED that is nailed up to an Ethernet port; other devices that might be attached to the port are blocked. The 802.11x Ethernet port security is best for more intermittent access; it intercepts new connections to Ethernet ports and works with central authentication servers such as RADIUS or TACACS+ to authorize newly attached users or devices. An important planning consideration is that advanced port security requires managed Ethernet switches. Historically, Ethernet architectures have often used managed switches for core switching, with simpler unmanaged devices for media extension and access aggregation around the edge of the network. Advanced port security features will push managed switch technologies further out toward the edge of the substation.

For Serial-IP-based port security, as with nailed up Ethernet ports, static IED connections can have static Serial-IP network definitions; however, remote console access is intermittent and on demand and it requires greater access control. The perimeter firewall and centralized access management systems will generally provide port access security for initial CIP compliance; however, planners should look for incremental opportunities to deploy Serial-IP technology close to – and eventually adjacent to – serial IEDs and then provide port- and user-specific authentication via security protocols optimized for serial-console applications, such as Secure Socket Layer (SSL). Serial Device Routers incorporate SSL technology and can be used to

extend dynamic Serial port security across a harsh substation environment.

RELIABILITY

Network reliability has three major factors: device reliability, media protection and resilient networking.

Device reliability can be addressed as part of every product selection. Within the substation environment, conformance to substation equipment standards IEEE 1613 and IEC 61850-3 is an important indicator that the equipment is built for survivability and extended Mean Time Between Failure (MTBF) in utility applications. These specifications address surge withstand, immunity and operating temperature range, among other factors.

Media protection means that all cabling connections other than very short runs within control house environments should use fiber optics rather than metallic media. Fiber optics provide both signal immunity and surge protection for attached devices. Most substation networks already use serial-over-fiber-optic Links/repeaters and optical stars for serial connectivity, and media converters when required for Ethernet connections, usually on point-to-point bases from the control house to distributed substation devices.

As substations evolve to an Ethernet core infrastructure, there is more opportunity to increase the resiliency of fiber network connectivity by adding dual-homing or ring topologies when linking to distributed devices. For Ethernet IEDs, there are a range of compact Ethernet switches, both managed and unmanaged, that can be distributed close to remote devices. These can support two connections back to the core network and can control network traffic rerouting with resilient software such as Rapid Spanning Tree Protocol (RSTP).

For serial-protocol IEDs, there are also recently available devices, sometimes called Serial Device Routers, that are hardened for distributed placement next to serial-based substation devices, with Serial-IP services and dual fiber-optic Ethernet connections to the core infrastructure. These devices have intelligent software to provide protection switching on both a local Ethernet basis (RSTP) and also for end-to-end network connectivity to remote master systems using dynamic IP routing and multi-master network features of advanced Serial-IP networking.

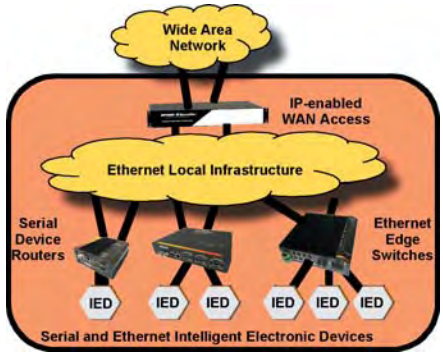

Figure 2: Resilient Connectivity of Distributed Devices to Ethernet Core Infrastructure

OVERALL COST EFFECTIVENESS.

Substation network planners are expected to keep project-specific costs down, but this does not always translate to purchasing the least expensive device(s) for the task at hand. Total

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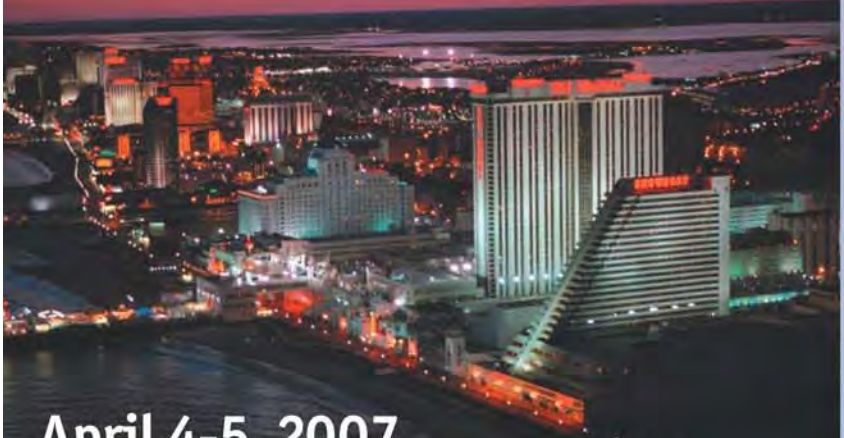

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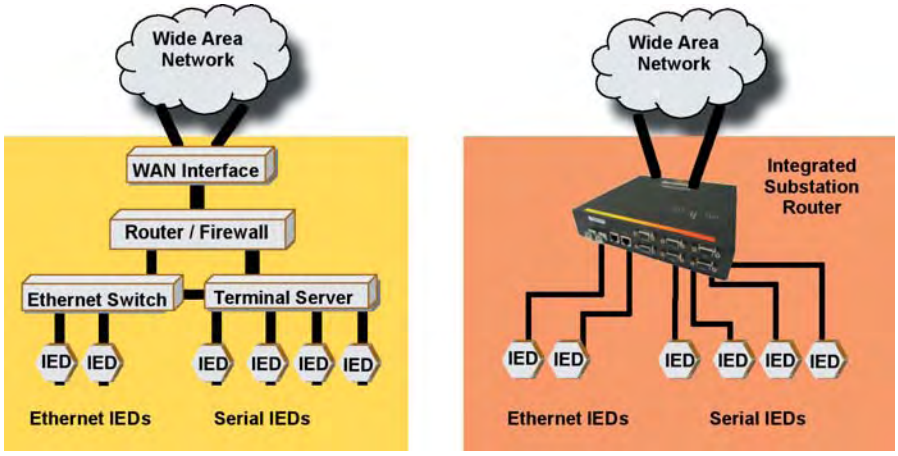

Figure 3: Functions of Substation Network Devices Available as Hybrid, Integrated Products

costs are also a function of ongoing maintenance, operational and telecommunications carrier expenses, as well as life cycle costs that are dramatically affected by early product obsolescence due to missing features or an inability to scale. For cost management it is important to minimize the number of discrete devices and suppliers required, and to have flexible growth options, both in terms of the number of ports and the physical distribution of connection points throughout a substation. Ultimately, the substation network should evolve with logical phases of incremental deployment.

In the largest substations, a near term design may utilize discrete networking products for WAN access, cyber security firewall functions, local Ethernet switching and Serial-IP services; in fact multiple distributed Ethernet switches and Serial-IP servers may be used. However, for initial integration projects at most small, medium and even moderately large substations, it may be more economical to utilize integrated multi-function network products. There are substation-hardened "routers" that combine all or many of the functions needed for substation network integration in a single unit, effectively providing a "one box solution" for network deployment. These may be deployed with only a few total ports or a few dozen, with a mix of Ethernet, serial and WAN connectivity.

Use of an integrated networking product should be viewed as only the first step in the evolution of the substation network. In the longer term, this key element can play a primary role as router/firewall at the WAN boundary, establishing the cyber security electronic perimeter. A likely second phase of deployment would be to add local Ethernet switches connected to this router to support growth of Ethernet-based IEDs and other Ethernet-based applications such as surveillance cameras. These Ethernet switches would also create a core infrastructure for supporting deployment of a more dynamic edge network. A third phase of network evolution would be the establishment of a dynamic edge network for connectivity to both Ethernet and serial devices. Managed Ethernet switches and Serial Device Routers can be gradually deployed further out into the substation network using dual or ring connections to the core Ethernet network. This architecture, employing both Dynamic Ethernet Edge and Dynamic Serial Edge technology, moves port security functions out adjacent to critical devices and extends network resiliency features locally throughout the substation. With compact devices, distributed device placement and a shared core infrastructure, the dynamic edge approach enables integrated substation networks to expand on a flexible, incremental and cost effective basis.

CONCLUSION

Many planners view an all Ethernet and IP network as the strategic target architecture, but few have an opportunity to implement and take full advantage of its strengths in a single-phased network deployment. It is important to understand the primary design objectives driving this universal architecture and then look for opportunities to move forward in each area progressively. Network consolidation, security, increased reliability and managed life-cycle costs can all be achieved with an evolutionary deployment approach. A responsible plan starts with a central integrating router/firewall network element, adds core Ethernet switches for scaling and provide a core infrastructure. The plan gradually pushes resilient and secure Ethernet-based Serial-IP and managed Ethernet switching elements throughout the substation as a reliable and secure distributed infrastructure. ■

About the Author

John M. Shaw is EVP of GarrettCom, Inc., a leading supplier of substation-hardened networking products. He has more than 25 years experience in telecommunications including executive roles at network technology start-ups and large carrier-equipment suppliers. As Director of data services at NYNEX (Verizon) he pioneered frame relay and fiber-based data services. He has extensive early career experience with design and implementation of large-scale utility-grade data networks. Contact him at jshaw@garrettcom.com

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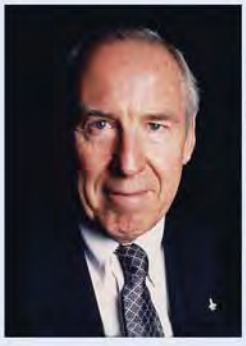

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Electrical contacts in MV & HV Power Circuit breakers

PREFACE

Electrical power transmission networks are protected and controlled by medium and high-voltage circuit breakers.

Breakers are meant to make and break the flow of electrical currents in transmission lines. Being so, the electrical contact function plays a main and critical role in the breaker's proper operation.

In the present article you will find a summarized description of the different types of electrical contacts used in power circuit breakers, the major risks to their proper operation and the principal tests used to verify their condition.

INTRODUCTION

A circuit breaker is an automatically operated electrical switch designed to protect an electrical circuit from damage caused by an overload or a short circuit. Unlike a fuse, which operates once and then has to be replaced, a circuit breaker can be reset (either manually or automatically) to resume normal operation.

Circuit breakers are made in varying sizes, from small devices, which protect an individual household appliance, up to large switchgear designed to protect high voltage circuits feeding an entire city.

The high voltage circuit breaker has three major components:

Interrupting Chamber: where the current conduction and interruption in the power circuit occurs. It is usually a closed volume containing the make-break contacts and an interrupting medium (compressed air, oil, SF6, vacuum, etc.) used for insulation and arc quenching.

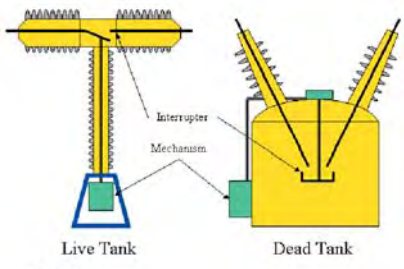


Fig 1

Operating Mechanism: where the needed energy to close or to open the contacts and to quench the arc is initiated.

Control: where the orders to operate the breaker are generated and its status is monitored.

ELECTRICAL CONTACTS IN CIRCUIT BREAKERS

As mentioned earlier, the power current passes through the conducting material in the interrupting chamber (fig 2). Various parts that are joined together form the conducting material. The different junctions form the electrical contacts.

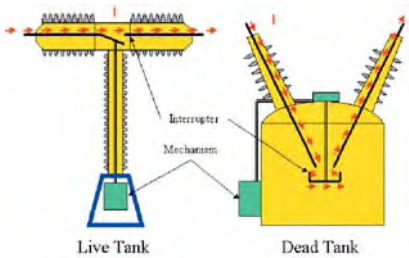


Fig 2

Electrical contact is obtained by placing two conducting objects in physical contact. This can be done in several ways. Even though there is a wide range of contact designs in interrupting chambers, they may be grouped in four major categories:

1. Make-break contacts - which may make or break under load;
2. Sliding contacts - which maintain contact during relative movement
3. Fixed contacts - which may be clamped together permanently for years and never opened.
4. Demountable contacts - which make or break off load. Usually seen in metal-clad medium voltage switchgear.

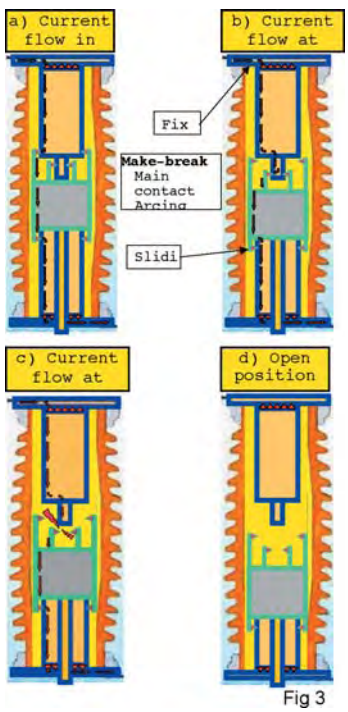


Fig 3

Figure 3 is a symbolic schematic of a typical contact architecture and clearly shows the current flow through three of the main types of contacts during the sequence of events of an open operation. In all three types, the contact is made by the touching surfaces of each component.

MAKE-BREAK CONTACTS

The types of make-break contacts can be subdivided by power rating, starting with the highest:

High current, high voltage circuit breaker contacts, which disconnect large electrical loads, and produce arcs, are contained within special arcing chambers. These may be in air at normal pressure or in a blast of air, in Sulfur Hexafluoride (SF6), in oil or another arc-extinguishing medium, including a vacuum.

It includes a moving contact and a stationary contact. Usually one of them is a ring of sprung copper contact fingers (insertion type, fig 4 or butt type), or the other is a solid rod of copper. The contacts may be tipped with an arc-resistant material to resist erosion from the high-power arc, and the surfaces may be plated (e.g. with silver) to improve conductivity.

Fig 4

The mechanical properties of copper combined with its excellent electrical conductivity and good arcing endurance in oil have made it the preferred metal in this application.

In vacuum circuit breakers, the contacts are also generally copper, mixed with tungsten and specially shaped to ensure proper distribution of the electric field and movement of the arc root.

Fig 5

Smaller air break circuit breakers (medium voltage), use copper in all internal conducting parts, but the contacts are often faced with a silver based alloy to resist welding. Such circuit breakers, being protective devices, rarely open or close.

SLIDING CONTACTS (Fig.5)

These can be of very different nature.

High speed, heavy current types, they are usually found in power interrupter Chambers.

These contacts must have a very high resistance to mechanical wear, as their relative speed may reach 10 meters per second or more.

FIXED CONTACTS

These include a wide range of bolted and crimped contacts.

A clamped joint avoids the reduction in cross section caused by drilling to insert bolts, and gives a more uniform distribution of the contact force, making the contact more efficient and hence running cooler. Bolting is used because it is cheap and convenient.

Crimped joints employ the ultimate extreme force of contact making, causing the metal to flow and make a permanent connection. The trouble-free nature of these joints, and the simplicity and rapidity of the crimping operation makes this type of joint very attractive for permanent connections.

Bolted or crimped contacts are used in interrupting chambers to secure and to maintain the integrity of the electrical component.

DEMOUNTABLE CONTACTS

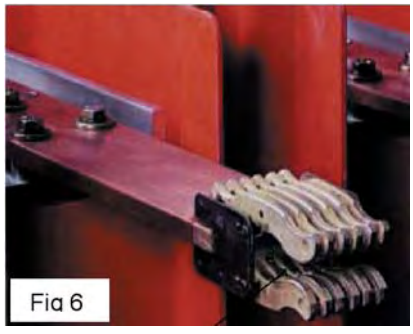


Fig 6

Found in medium voltage metal clad breakers. It helps in taking the breaker off the network by easily sliding it off the bus bars for maintenance purposes. This has to be done off load.

These contacts, like the make-break contacts, may be carrying high currents at high voltages (e.g. high voltage isolators or high or medium voltage fuse contacts). They have to carry current reliably for long periods, without overheating or loss of contact, but do not make or break current. They are not subjected to the stress of arcing; hence they do not get the inherent cleaning action associated with it. They are frequently designed to have some frictional action on closing to remove superficial oxide or corrosion films which might impede contact, and copper and its alloys are the most frequently used materials for the bulk of demountable contacts.

The characteristic of these contacts is that they have a high contact force, much higher than for circuit breakers of similar current rating, but not so high as the contact force in a bolted contact, because of the excessive mechanical wear which would be caused when separating the contacts

CONTACT RESISTANCE

As we said, the contact occurs when two surfaces touch. For the electric current, if it is conductive material, it means a path for it to flow.

Observation on a microscopic scale shows that the contact surface is actually rough even though it seems smooth to the unaided eye.

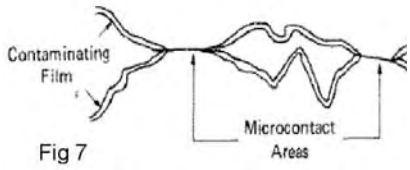


Fig 7

In fact, as the microscope shows, the real contact between two surfaces happens through a number of small surfaces, called microcontacts (fig 7), spread randomly inside the limits of the visible contact area.

It is the sum of the areas of all the microcontacts that constitutes the effective contact area.

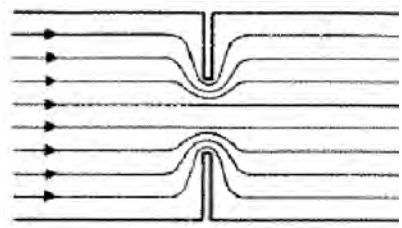


Fig 8

Since the resistance of an electrical contact is inversely proportional to the contact area, the smaller the effective area the greater the resistance. (fig 8)

EFFECT OF CONTACT RESISTANCE

When a current **I** pass through an area **A** that has a resistance **R**, The Energy **E** absorbed by **A** is:

$$E = RI^2t$$

Where **t** is the time duration of **I**.

We know that **A**'s temperature **T** is directly related to **E** by the following equation:

$$E = \lambda T$$

λ is a function of the heat dissipation rate.

For a constant current I_o, if **R** increases, **E** then increases, leading to increasing temperature of the contact. If **T** continues to increase the material of the contact can reach its melting point, leading to its destruction. (fig 9)

Fig 9

ELEMENTS AFFECTING THE CONTACT RESISTANCE

OXIDATION

A thin layer of insulating oxide covering the area of a single microcontact would have little effect on the conductivity of the contact as a whole. As soon as the oxide layer extends to a significant number of microcontacts, the current-bearing area would reduce, thus increasing its resistance. Increased resistance will increase the contact temperature, leading to its destruction.

All ambient atmospheres that contains gases capable to react with the contact's material, such as O2, SO2, H2O, H2S, etc., would be favorable to producing oxide layers even though the contact is closed. With time, the gas would succeed in penetrating and reacting with the contact surface to degrade its characteristics and to increase its resistance.

WILLIAMSON studied the phenomenon. Fig 10 shows the resistance value increasing with time. As we can see, the resistance change is not significant until a certain point in time where the degradation increases fast. Similar results are obtained by LEMELSON for copper contacts in oil.

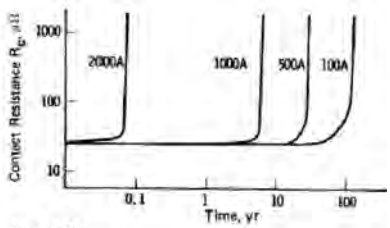


Fig 10

These results show interesting behavior and indicate the urgency of a maintenance intervention when a contact's resistance starts to increase.

CONTACT WEAR

Mechanically, it can be due to the movement and friction of the contacts and electrically due to the arc effect (mainly the make-break contact). Contact wear directly affects the contact resistance and makes it increase dramatically if the wear is in an advanced state (fig 11).

FRETTING

A form of accelerated oxidation is possible, if the contact surfaces experience a cycling movement relatively to each other. For example, the contacts would not close at the same area each time.

Fig 11

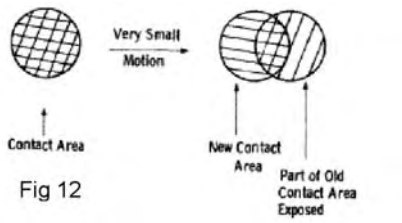


Fig 12

This phenomenon was noticed long ago but its magnitude was recognized only recently. When a contact moves from its previous position, a part is exposed to the ambient atmosphere. An oxidation layer then forms. When the contact goes back to this position, it breaks the thin layer and pushes it aside. This phenomenon repeats many times until the oxidation layer becomes of a significant thickness, enough to increase its resistance.

BRAUNOVIC has experimented the fretting phenomena with low currents in aluminum, and JOHNSON & MOBERLY have studied it on high currents and reached similar results.

The resistance increases rapidly right after it starts to change. Fig 13 shows similar case to fig 10, but accelerated.

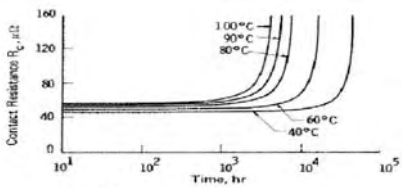


Fig 13

CONTACT FORCE

As known, the resistance **R** is function of the contact material's resistivity **p** and area **S**, ($R = \rho / S$).

$$R = k\varrho\frac{H}{F}$$

S is the sum of all contact points areas. The contact points areas are function of the applied force **F** and the material hardness **H**, (**k** is a constant)

If **F** decreases, **S** decreases as well and **R** then increases.

F can decrease due to different factors, for example:

1. Excessive wear of contact surface;
2. Fatigue of contact springs over time;
3. Chemical reaction of spring material with ambient atmosphere;
4. Loose or misaligned contact, etc.

Spring materials are thus an important element to take into consideration. By the same logic, an important precaution to take is to avoid letting the spring be a current path, as the increase in its temperature would cause a weakness of the resultant force **F**.

TEMPERATURE

For an increasing temperature **T** of the contacts, the material of the contacts may soften to the point where it will reduce the contact force, leading to a quick increase of the contact resistance.

TESTING

We have seen above that oxidation, wear, fretting, force and temperature directly affect the resistance value **R** (in microohms) of the contacts.

So, to easily assess the conditions of the breaker contacts, two types of tests, to both statically and dynamically measure **R**, have established themselves and are widely in use.

CONTACT RESISTANCE MEASURING

Measuring the contact resistance is usually done by using the principles of Ohm's law **V = RI**;

V is the voltage across the contact;
I is the current;
R is the resistance.

If we apply a current **I** and we measure the voltage **V**, the resistance **R** can be obtained directly by dividing **V** by **I**.

R= V/I

As seen in fig 14

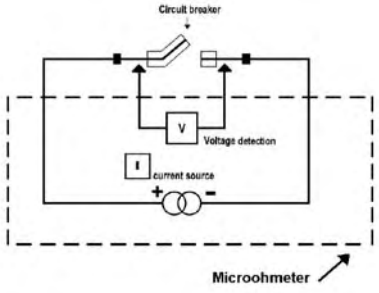


Fig 14

Since the interrupting chamber is a closed container, we have only access to the entry and exit conductors; the measured R between these two points would be the sum of all the contact resistances found in series, (fixed, make-break and sliding contacts).

According to the IEC 694, article 6.4.1, the current value to use should be the closest to the nominal current the interrupting chamber is designed for. If it is impossible to do so lower currents can be used but not less than 50A to eliminate the galvanic effect that might affect the readings.

Special precautions should be observed when measuring:

1. The measured points have to be clean and free of oxidation;
2. The measurement points should always be the same each time;
3. Perform several consecutive tests and calculate the average.

The unit used is micro ohm ($\mu\Omega$).
$1\ \mu\Omega = 10^{-6}$ ohms (Ω)

We can keep in mind that the range of microohm resistance values found in breakers is roughly divided according to the voltage and current carrying capacity:

- 25 kV – 100 to 350 $\mu\Omega$;
- 120 kV – 80 to 200 $\mu\Omega$;
- 120 to 330 kV – 100 $\mu\Omega$ maximum.
- 735 kV – 20 to 80 $\mu\Omega$.

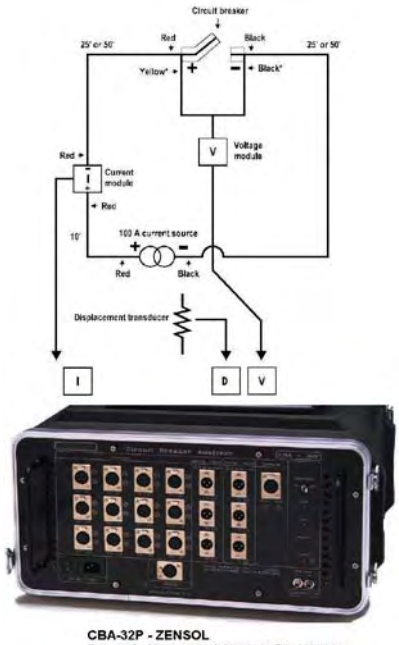
DYNAMIC MEASUREMENT OF CONTACT RESISTANCE

The micro-ohmmeter described above is used to measure the contact resistance with the interrupting chamber in the closed position, but it does not give any indication of the condition of the arcing contacts.

One option is to do an internal inspection but it is time-consuming. In the case of SF6 breakers, maintenance procedures must be strictly followed in order to safely handle the SF6 gas and arc by-products. It is why dynamic contact resistance measurement has been developed.

By definition, as its name suggests, starting from a closed position, as the contact moves to its open position, a current is injected and the voltage is measured. This will give us the resistance value all the way from the closed to the open position.

This test needs special equipment (fig 15) and a more complicated procedure compared to the static one. The information collected is of a different nature and give us more insight of the contact's condition that could not be available with the static test.



CBA-32P - ZENSOL
Dynamic Measure of Contact Resistance

Fig 15

It is not relevant to discuss the dynamic test in detail in this article. But we can bear in mind that this test is able to give us good information on the resistance value of the arcing contact and the eroded part of it.

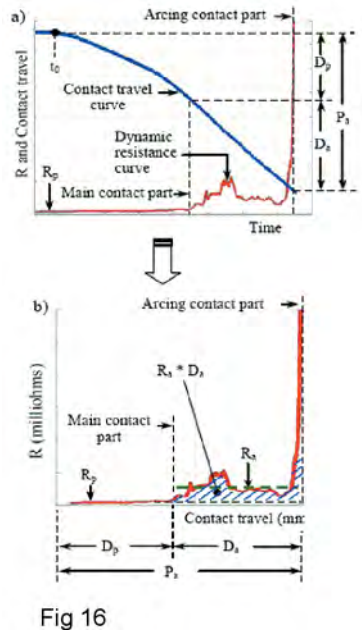


Fig 16

This information is crucial for certain breakers, where the quality of arc quenching is greatly affected by this fact. The effect would be so great that it might lead to the explosion of the interrupting chamber.

We also have to know that performing a dynamic contact resistance measurement on butt contacts makes no sense. A simple static test with a micro-ohmmeter is sufficient due to the architecture of the contacts.

So before using the dynamic contact resistance test, you need to check the types and the mechanical architecture of your breaker. This subject will be discussed in more details in our next article.

SUMMARY

The electrical contact is a crucial component in power circuit breakers. An increase in the contact resistance can cause the failure of the breaker. We have seen that all the elements affecting the contact resistance will reach the same result. If the contact resistance starts to increase significantly the increase in value will grow exponentially.

The IEC 56 international standard sets an acceptable reading of up to 20% increase from the original test value. Over this value, it is necessary to perform an open inspection.

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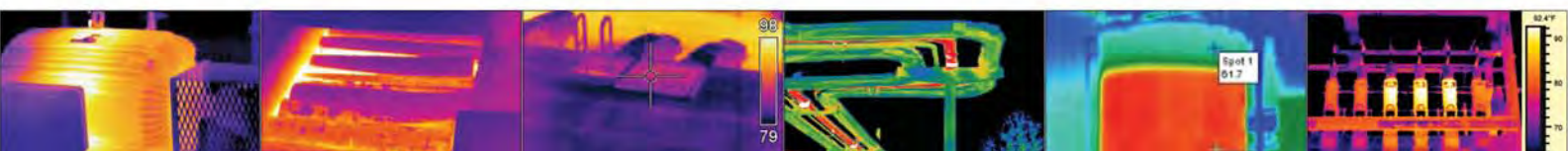

It is important to take special precautions while testing since false readings can cause frequent and unnecessary maintenance.

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About the Authors

Emile Nasrallah *is an electrical engineer specialized in Power circuit breakers maintenance.*
Since graduation in 1984 he worked as a field engineer. In1990 he joined the worldwide circuit breaker manufacturer GEC ALSTHOM as a specialized field engineer. In 1997 he became the manager of MV & HV circuit breaker SF6 division of ALSTOM, responsible of technical support, maintenance and training for SF6 circuit breakers. In 2001 he became manager of Air blast circuit breaker division for AREVA. He was in charge of the Air blast (PK and PKV) refurbishing program in partnership with hydro-Quebec and introduced a unique administration system for the program (average of 35, 735 kV PK air blast circuit breaker per year). In 2005 he joined General Electric Company of Canada as a senior circuit breaker specialist and is in charge of the circuit breaker division of the Montreal service centre, responsible of the remanufacturing program for Oil circuit breakers

Stéphan Perron*, Hydro-Québec teacher, High Voltage breaker maintenance*
Stéphan Perron has been teaching maintenance and trouble shooting of High Voltage Circuit Breakers and Thermography for more than 7 years at the Hydro-Quebec Competence Center based in Saint Antoine des Laurentides, QC, Canada. He developped his expertise by working on the maintenance side of the High Voltage Circuit Breakers of Hydro-Quebec for 18 years. His specialties are the ABB (models SFE, HPL, ELF and DLF) breakers, the GE (models KSO, AT) breakers and all the related test instruments, as well as the sectionnors Joslyn VBM, the handling and behavior of the SF6 gaz and interpretation of thermagraphic readings (Level 1) on breakers. Stéphan Perron holds a DEC degree in Electronics from the CEGEP St Jérome, QC, Canada

Dr. Fouad Brikci *is the president of Zensol Automation Inc. He was the first to introduce the concept of truly-computerized test equipment in the field of circuit breaker analyzers. As a former university teacher in Ecole Polytechnique — Algiers and CNRS - LAAS researcher in France, Dr. Brikci has developed experience in the fields of electronics, automation, and computer science. Most activities were focused on the industrial application of computers. Among his achievements are the development of fully comput¬erized measuring systems for quality control in circuit breaker manufacturing, laboratories, and maintenance services of electric utilities. Dr. Brikci holds a PhD in Electronics and a Master in Sci¬ences in EEA (electronics, electrotechnics, and automation) from the University of Bordeaux, France.*
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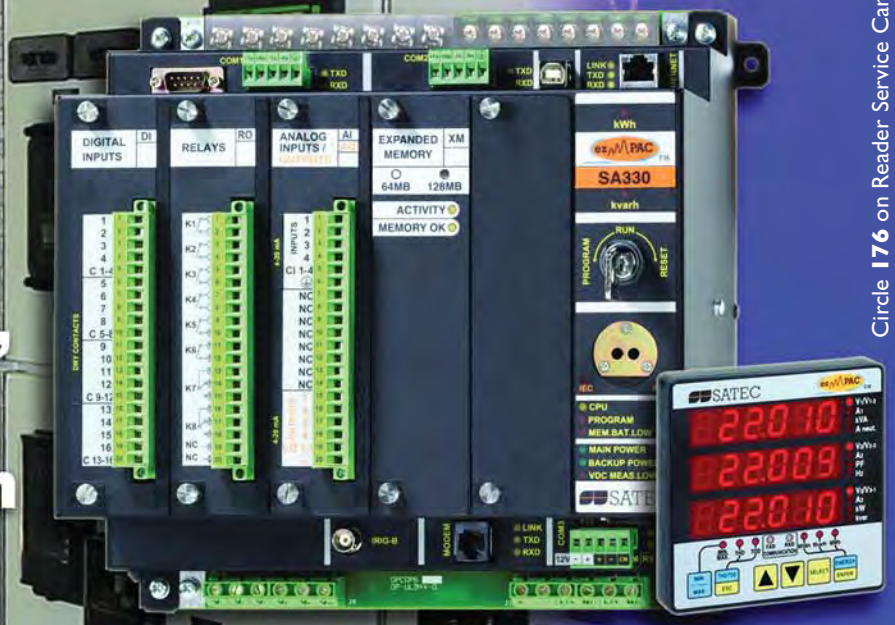

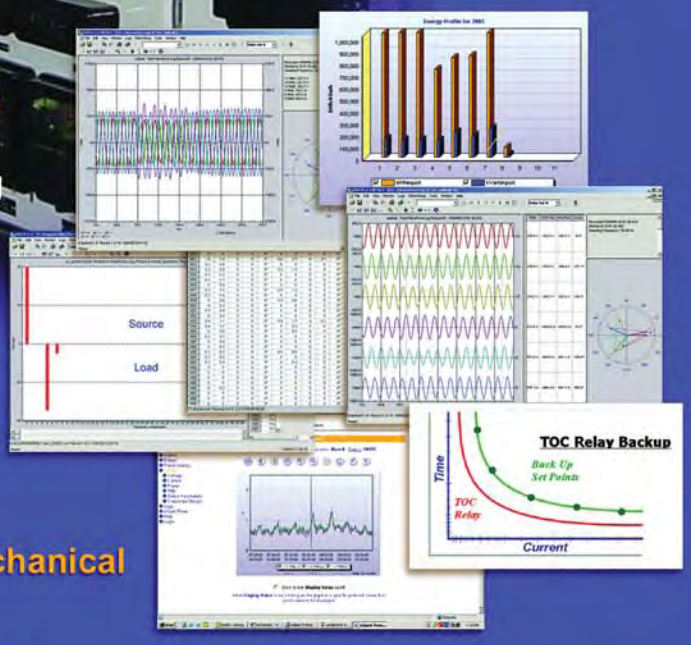

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