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Electric Energy T&D MAGAZINE

JANUARY-FEBRUARY 2008 Issue 1 • Volume 12

In this Issue

The Role of AMI in the Integration of Demand Response into Ontario's Supply Mix

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Encryption over TCP/IP
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Remote Hardware Authentication
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Real-Time Access Reporting
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Modem Disable Capability
Modem Call Schedule Capability
Encrypts Dial-Up Link Connection
IED Protection
Centralized User Authentication
Integration w/3rd Party Vendor Tools
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Centralized Device & User Mgmt
Disaster Recovery & Failover Support
SCADA Protocol Agnostic
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LZW Compression
Serial Bit Protocol Support
TCP/IP Link Support
High Speed Bit/Byte Translation
Centralized Event Log Aggregation
Synchronized Time Stamping
Intrusion Detection Capabilities
Comm. Data Capture Capability
Centralized Data Capture, No Cabling
Millisecond Level Resolution Capture
Capture Integrated With Link Security
Protocol Analyzer Capability
Server Platform Independent
No O/S in Field Devices
Centralized Firmware Upgrades
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Product Specifications
Operating Temperature -40°C to 85°C
Power Input Range 12 - 150 VDC
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Rack Mounted Enclosure Available
Pole-Top Enclosure Available
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IPC Class 3 certified
Other Certifications:
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CAN/CSA C22.2 No. 60950
EN60950
EN55022
EN55024
ICES-003
FCC Part 15 Class A

Configurable Parameters
Command Timeout
Pass-through mode, no packetization
Pass-through mode, packetization
Device Discovery Timeout
Key Exchange Timeout
Key Expiration Interval
Max File Trans Retries
Max Ping Loop Count
New Device Interval
Packet Retry Count
Ping Loop Timeout
Host Serial Port Baudrate
Host Serial Port Data Bits
Host Serial Port Parity Bit
Host Serial Port Stop Bits
Host Serial Port Flow Control
Host TCP Port Number
Host TCP Reconnect Timeout
Host Link Type (byte or bit)
Host Clear Port Type (serial or Ethernet)
Host Secure Port Type (serial or Ethernet)
Host Link Keep Alive Timeout
Host Link Send Timeout
Host Link Receive Timeout
Host Max Payload Size
Host Link Dictionary Update Time
Host Link Dictionary Transfer Time
Host Link Master Dictionary Reset Time
Host Link Dictionary Update Ratio
Host Conservative Mode
Host Maximum Control Packet Delay
Host Switched Carrier
Host CS RTS Preamble
Host CS RTS Postamble
Host SC RTS Preamble
Host SC RTS Postamble
Host Remap CD to DTR
Host Store and Forward
RSM Type
RSM Byte Port Baudrate
RSM Byte Port Data Bits
RSM Byte Port Parity Bit
RSM Byte Port Stop Bits
RSM Byte Port Flow Control
RSM Bit Port Baudrate
RSM Bit Port Data Bits
RSM Bit Port Stop Bits
RSM Bit Secure Port Handshaking
RSM Bit Clear Port Handshaking
RSM Secure Port Receive Mark
RSM Secure Port Send Mark
RSM Secure Port Send End Mark
RSM Clear Port Receive Mark
RSM Clear Port Send Mark
RSM Clear Port Send End Mark
RSM Link Keep Alive Timeout
RSM Link Send Timeout
RSM Link Receive Timeout
RSM Max Payload Size
RMD Line Number Choices
RMD Initialization String
RMD Login Retries
RMD Login Delay
RMD Login Timeout
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Electric Energy Magazine is published 6 times a year by: Jaguar Media Inc.
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Tel.: (888) 332-3749 • Fax: (888) 243-4562
E-mail: jaguar@jaguar-media.com
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Post Publication mail agreement #40010982
Account #1899244

COVER PAGE PHOTO: www.photos.com

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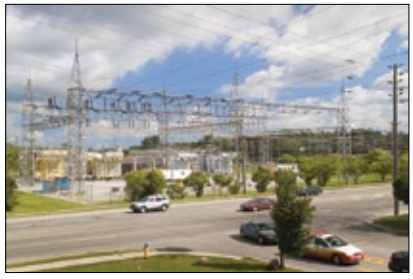

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Trilliant Growth Drives Expansion into New Facilities

Advanced meter infrastructure (AMI) and meter reader company Trilliant holds official inauguration of its new facility in Granby's industrial park on December 10th.

Trilliant Incorporated, the company recently formed through the merger of OZZ Energy Services and Trilliant Networks, is a good example of how growth from the AMI market is driving expansion across multiple locations. Earlier this year Trilliant expanded its headquarter operations in Redwood City, CA to include a new solutions development and training facility. In December the company moved into a larger facility to support growth in Granby, QC. The company also maintains operations in Concord, Ontario where the Trilliant Energy Services (former OZZ Energy Services) continues to run its business.

"The growth in business across North America, in combination with continued investments in research and development, has driven the demand for new facilities," said Paul Karr, vice president of marketing at Trilliant. "The new space allows us to better serve our customers while also supporting a great work environment critical for attracting the industry's best talent."

STRONG GROWTH

During the last two years, the company's wireless energy management networking technology has added significant new customers and expanded relations with existing companies. Notable projects include a multi-year contract with Hydro One, the largest electricity distributor in Ontario, to supply 1.3 million meters and the recently announced complete AMI and revenue assurance solutions to support all priority commercial and industrial (C&I) customers for Jamaica Public Service, the sole distributor of electricity on the island of Jamaica.

Another recent Trilliant new customer, E.ON U.S. (Louisville Gas & Electric), is deploying an integrated AMI and demand response solution. This innovative program will empower consumers to better manage their energy use patterns, providing cost savings and helping limit carbon emissions by automatically reducing energy consumption during critical peak periods.

Trilliant has more than 350 employees across its North American locations and expects to see continued growth in the year ahead.

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Yazoo Valley Electric Selects Cellnet+Hunt TS2 For AMI System Deployment

ATLANTA January 2008 – Yazoo Valley Electric Power Association (Yazoo Valley Electric), an electric cooperative utility located in central Mississippi, has begun deploying the TS2 advanced metering solution from Cellnet+Hunt.

Yazoo Valley Electric will fully deploy the TS2 system to over 10,000 meters. The utility cited Cellnet+Hunt's strong customer service track record and proven technology as key reasons for their selection of TS2.

Ronald White, Yazoo Valley Electric's Manager of System Services, said, "The cost savings from manual meter reading was key to our business case, but we're also looking forward to using the system's two-way capabilities to provide enhanced services to our customers."

Yazoo Valley Electric provides reliable power for over 9,300 residential and over 900 commercial customers from its headquarters in Yazoo City, MS. With a distribution system comprised of over 2,700 miles of line that cover portions of six counties, Yazoo Valley Electric's 3.2 customers per mile of line make it one of the most geographically dispersed electric cooperatives in the Southeast United States.

"We're rolling out to the first substation now, and the recent project kick off workshop was a good opportunity for our team to learn about the customer service possibilities available with the new system," said Rebecca Yeates, Yazoo Valley Electric Member Services/ Communications Coordinator.

A power line carrier (PLC)-based communication technology, TS2 is a full two-way advanced metering system that offers demand response capabilities, such as load control and time-based pricing, as well as distribution system monitoring and load profile capabilities.

Cellnet+Hunt serves its growing rural electric cooperative customer base from a dedicated center for cooperative and public power located in Pequot Lakes, MN and through a network of field offices and local partners located across the United States. For more information visit *www.cellnethunt.com*.

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Enspiria® Solutions to Assist Pepco Holdings in AMI System Acquisition

Denver, CO January 2008 – Enspiria Solutions has signed an agreement with Pepco Holdings, Inc. (PHI) in Washington, D.C. to assist with its AMI technology and end-point installation system acquisition.

PHI has plans to implement an AMI solution as an integral component of its Blueprint for the Future, an ambitious proposal for investing in innovative technologies and initiatives that will help PHI's electric utility customers manage their energy more effectively, reduce the total cost of energy and protect the environment by reducing greenhouse gas emissions. AMI will also help PHI customers by identifying and resolving outages more quickly, improving system reliability, and facilitating programs that help customers save energy.

"PHI's vision of the future includes the conversion of our metering system from electro-mechanical to digital, a

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transformation that will evolve over a period of years and allow us to expand and improve our services and programs. Enspiria Solutions has the knowledge and experience to assist us in developing the functional and technical requirement specifications for the new metering technology and end-point installation including all aspects of the system," said Todd McGregor, AMI project sponsor for PHI.

"Pepco has a comprehensive vision of the future that will provide its customers increased energy efficiency, demand response, and pricing options that are enabled by new technology. We are proud to support the utility in this important initiative," said Jeff Evans, Principal Consultant with Enspiria Solutions.

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Über-Rugged™ Ethernet Solutions - Introducing the RSR Series of RFI/ EMI-Hardened Ethernet Switches

- Up to 9 Fast Ethernet ports with 3 Gigabit (RJ45/SFP) uplinks
- DIN rail or wall-mount full-metal housing
- IEEE 1613 Class 2, IEC 61850-3 and NEMA TS-2
- Fan-less -40° to +85°C (+185° F) operating temperatures
- Redundant 16.8 – 60 V (DC) or 48 – 320 V (DC) or 90 – 265 V (AC).
- Multiple options for network resiliency (as fast as sub-10ms)

Hirschmann Automation and Control will introduce a new series of RSR manageable switches at Distribuech - booth 1738. RSR Über-Rugged™ managed Ethernet switches are built to exceed the extreme environmental and availability demands of power generation, distribution and other mission-critical applications.

Available in a 100 mbps (RSR 20) and a Gigabit Ethernet version (RSR 30), they are designed for extremely high availability applications that may have shock and vibration as well as electromagnetic interference. They have a compact metal housing (125x140x120 mm / WxHxD) that can be wall or DIN rail mounted.

With a -40° to +85°C (-40° to +185° F) operating range, RSR Ethernet switches are ideal for new or retrofit installations with high ambient temperatures, electromagnetic/ mechanical stress, and condensation.

The switches have up to nine Fast Ethernet ports (100 BASE-TX/FX) and a maximum of three Gigabit Uplinks (1000 BASE-TX). The RS30 uplinks are designed with RJ45/SFP combo-ports for optional implementation for multimode or singlemode fiber.

Fast HiPer Ring, Rapid Spanning Tree and link aggregation ensure a high network availability. Security mechanisms include access control in accordance with IEEE 802.1x , IP and MAC port security as well as SNMP v3 and SSH.

Fan-less cooling and redundant power supply (16.8 – 60 VDC or 48 – 320 VDC or 90 – 265 VAC) ensure high operational reliability. Switch status, detailed information and faults can be displayed by a web browser or integrated into the automation software. Another advantage is the integrated SNMP interface which enables the use of a network management software, permitting for the management of an entire network of switches from a single screen.

RSR switches meet or exceed NEMA TS-2, IEEE 1613 and IEC 61850-3 requirements.

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2008 TRANSMISSION AND DISTRIBUTION CONFERENCE AND EXPOSITION SCHEDULED

For Chicago, Illinois, Usa, April 21-24, 2008

Global Event Features A Comprehensive Technical Program and Exposition

The 2008 IEEE Power Engineering Society Transmission and Distribution Conference and Exposition is designed and organized to provide today's power-delivery professional with the information and detail necessary to manage technology and business solutions better in the years ahead. The host utility for the 2008 event is ComEd. The site of the Conference and Exposition is McCormick Place in Chicago.

The Industry's Premier Event has been created to provide attendees, with information that concentrates on the world of transmission and distribution and all of its elements -- a focused, yet thoroughly comprehensive event that will draw the highest attendance of t and d professionals from around the world.

Powering Toward the Future has been selected as the theme for the event. Attendees will gain authoritative analysis and insight into these key areas: overhead and underground transmission and distribution systems, safety and grounding, maintenance and operation, distribution generation, power quality, FACTS and HVDC, distributed system planning and reliability, transformers, circuit breakers, cables, lightning and insulators, series and shunt capacitors, switching surges and overvoltage phenomena, towers, poles and conductors, switchgear and fuses and protective relays.

The 2008 event will feature a comprehensive program of technical presentations and an exposition that will include displays from leading manufacturers and suppliers from around the world. The conference provides super sessions focusing on the major topics facing the industry and a series of poster and panel sessions, tutorials, solution and info sessions, educational tracks and a collegiate program and technical tours that have been designed to enhance an attendee's technical knowledge base. Tours will also be organized for those attendees being accompanied by spousal companions.

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Intergraph InService SmartConsole

HUNTSVILLE, Ala. – The growing challenges for utilities to provide more reliable power, contain costs, and move to "greener" energy delivery is increasing the demand for an intelligent or "smart" grid. To help utilities meet these challenges, Intergraph Corp. introduces InService SmartConsole, a unified and complete command and control environment for visualizing and integrating smart grid technologies. InService SmartConsole plays a vital role in improving operational response and reducing outage impacts and frequencies. The application quickly detects and addresses outages and potential problems with electrical networks. In addition to managing the "self healing" functions of the smart grid by automatic adjustments in load flow and switching, operations personnel can have access to full trouble reporting and mobile workforce management to efficiently address restoration efforts.

The InService SmartConsole solution is designed to be the single operations environment capable of managing the entire distribution network. This command and control application can gather data from a variety of disparate detection sources, including video surveillance and critical infrastructure protection technologies, and convert this information into alarms, events and work orders.

The SmartConsole solution is based on Intergraph's InService technology which features integrated outage and workforce management technology in a single application environment. This technology uniquely provides both dispatchers and field crews with views of the same maps, graphics and dispatch information with integration to multiple smart grid technologies.

The SmartConsole solution automates many processes typically handed manually, freeing up valuable personnel resources and increasing operational efficiency. The automation controlled in the InService SmartConsole solution includes automatic generation of switching steps for load transfers, disabling of automated devices for manual switching, fault isolation and field order generation.

The InService SmartConsole tools provide a consolidated view of the entire network operations. Instead of monitoring the network in a SCADA system, making changes in OMS, using automated vehicle location (AVL) to find a field resource, and calling the resource to assign a work order, users of the SmartConsole will benefit from accessing all of this information through a single interface. By monitoring the entire network and field resource pool using a single console, operators and field personnel will experience higher productivity and increased safety.

As technologies continue to evolve, Intergraph's InService SmartConsole will prove to be a vital piece in the delivery of reliable power.

For more information, visit Intergraph at *www.intergraph.com/promo/smartgrid.*

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New Standards for Surge Protection Devices: Are you Ready?

A new UL Standard for Surge Protection Devices is fast approaching. UL 1449 3rd Edition was published on September of 2006 with a required compliance date of September 2009. This 3rd Edition Standard not only encompasses all of the changes that were designated in the latest revision of the 2nd Edition, but also an even more stringent set of safety requirements.

So, why would you buy products tested to the old Safety Standards when you could get UL 1449 3rd Edition tested products for the same price?

The UL OWHX Standard for Secondary Surge Arrestors will be obsolete in September 2009. This Standard will also be replaced by the new UL 1449 3rd Edition Standard.

Out with the Old, In with the New

Meter-Treater's Surge Protection Devices have already passed testing using the UL 1449 3rd Edition Specifications. "We decided to be pro-active and test to the new safety standards in order to be in full compliance". Meter-Treater's Surge Protection Devices are one of the few in the industry that you can obtain right now that are listed to the UL 1449 3rd Edition Standard.

Change is Good for Some

As a result of the 3rd Edition, Surge Protection Devices are subjected to a more severe series of Surge Withstand, Fault Withstand and TOV Safety Tests than ever before. This may necessitate major design changes to many of the 2nd Edition Listed Products that are on the market today. At that time, replacement parts may become very scarce for products that were not designed to meet the new standard.

Meter-Treater's product owners will not need to worry about availability of parts or components for older product designs; "Our 3rd Edition components have been designed to be compatible with products that are currently in the field. We wanted to ensure that our customers were not impacted by the transition from 2nd to 3rd Edition".

Do your Homework

In order to know whether or not your manufacturer is in compliance you can contact their respective Nationally Recognized Testing Laboratory (NRTL) for confirmation. For a complete list of approved NRTL's you can check the US Government OSHA website.

For additional information visit:
www.metertreater.com.
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PPL Electric Utilities Taps Advanced Control Systems For Distribution Smart Grid Program

ATLANTA, GA — January 2008—Advanced Control Systems, Inc. (ACS) announced today that it has successfully installed the first phase of its distribution reliability smart grid program for PPL Electric Utilities. ACS completed installation at PPL of the first network portions of a self-healing smart grid automation program that ACS has branded FASTapps™.

FASTapps is an open, powerful substation platform which supports innovative smart grid real-time feeder and substation automation applications. These applications provide the utility industry its first network model-based self healing electric grid solutions for distributed applications.

PPL is working to increase the reliability of its feeders through the application of ACS smart grid technology. FASTapps incorporates an adaptive, model-based approach designed to detect feeder faults resulting in outages to provide isolation and automatic restoration of un-faulted feeder sections.

ACS Smart Grid Solutions Improve:

- Reliability through 'self healing' networks incorporating fault detection, isolation and restoration.
- Power quality applying loss minimization to improve power factor.
- Distribution grid efficiency with distribution network load balancing.
- Economics through applications such as Volt Var control to minimize voltage on the feeder network.

PPL Supervising Engineer Howard Slugocki said, "We are pleased to work with ACS on this important smart grid project that is expected to improve the reliability and service we provide our customers."

Howard Slugocki will present a paper related to the deployment at the upcoming DistribuTECH conference entitled "An Innovative Approach to Distribution Automation." Slugocki will participate in the session "Innovative Integration of Protection and Automation For Feeder Restoration" that will be held Tuesday, January 22 at 3PM.

ACS CEO Jose Barbosa concluded, "PPL has been a great company to partner with in deploying and perfecting these new smart grid solutions. FASTapps employs distributed intelligence and automated control to deliver new levels of distribution reliability and customer service."

For more information, visit:
www.acsatlanta.com.
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By Michael A. Marullo, Contributing Editor

Everything New is Old Again

Well, it's a new year and as we all know, this is the time when we're supposed to leave the old behind and focus on the new. It's a time to look toward the future. But the title for this editorial is meant to be more than just a clever twist on an old cliché. I chose this title because it's a near-perfect fit for the topic that I wanted to spotlight in this first issue of 2008: Reinvention of the grid. Whether you call it the "Smart Grid" or "Intelligent Grid" doesn't really matter much in the grand scheme of things, but precisely what those terms portend for the electric utility industry over the next decade or so – now that's something worthy of comment…

Of the many things we're being told almost daily about this so called next-generation grid, it surely seems that it will be a lot smarter than what we've had until now; more 'intelligent' if you will. And, although no one has a complete road map for exactly how or precisely when this magical transformation is going to take place – despite the occasional claims to the contrary – there are a few things you can probably count on: 1) It will take a long time, 2) it will cost a bundle, and 3) it will be great when it's all done. (Moral: Getting smarter is hardly ever quick or cheap, but it usually does pay off - eventually.)

Among the various grid initiatives that will necessarily be undertaken in this new year – and by all indications, for many years to come – is the need for utilities far and wide, large and small, to completely re-think not only their future automation/IT spending plans, but also the vast majority of their existing automation/IT infrastructure. Even some newly installed systems may well be rendered obsolete once the intelligent grid really gets rolling, making what was considered 'new' just a few months ago suddenly not seem so avant-garde today. (See how well that title fits?)

A good example of this emerging anomaly is the automatic meter reading business. After nearly three decades of AMR pilots, proof of concept projects and more recently, roll-outs of one-way (i.e., read-only) AMR systems at a cost of millions of dollars, utilities' worst fears about AMR are being realized; that is, betting on the wrong technology for full deployment. Many of those one-way systems – some of which are only a few years old – must now be re-evaluated and made to conform to advanced metering infrastructure architecture and performance criteria if the benefits of an intelligent grid are to be fully realized.

But reinventing the grid certainly goes beyond just AMR, way beyond. In fact, I believe that automation/IT is at the beginning of a renaissance. After decades of being on the fringes of utility spending, it now seems inevitable that automation/IT is about to go mainstream. The many reasons why this market surge is poised to begin now include, but are not necessarily limited to, the following.

1. **Workforce:** It is a well-known fact that the most experienced utility staff will be leaving the workforce in droves over the next decade, just at the time when they are needed most. Meanwhile, it is becoming equally clear that there will not be enough new engineers and technical staff available within (or even outside) utility enterprises to replace those who are leaving in a timely or efficient manner. This means that alternative resources must be found to take up the slack, and automation/IT solutions should be at the top of that list. Of particular note is the need for knowledge-based systems to capture at least a portion of the brain trust before it is lost forever.

2. **Infrastructure:** We also know that a huge portion of existing grid assets are approaching the end of their (statistically projected) useful life. Of course, there is simply no way to replace them all simultaneously, and even if there were, the cost would be astronomical. Therefore, various types of life-extending measures will have to be applied, many of which will necessarily require innovative automation/IT solutions, particularly in view of the aging workforce challenges described above.

3. **Budgeting:** Under the traditional utility budgeting model, each component of automation/IT was usually evaluated separately, often with little or no consideration given to the impact and/or benefits projects in other areas might have on them individually or collectively. However, recent research shows that utilities are slowly beginning to move away from that approach, as evidenced by scores of projects in one discipline being delayed or otherwise placed on hold pending decisions and/or outcomes of decisions associated with projects in other automation/IT application areas.

4. **Reorganization:** Utilities are always reorganizing for one reason or another, but the integration of engineering with IT (information technology) departments is arguably the most complex and far-reaching organizational change to be undertaken by utilities in recent history.

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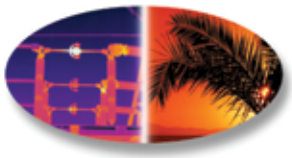

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For most enterprises, this organizational merger has certainly not been quick or easy, yet despite the obvious culture clashes and differences in professional opinion as to the best way to plan and execute specific projects, the integration process remains ongoing on both a personal and infrastructure level. In the end, utilities must find better ways to plan, design, implement and support integrated automation/IT programs efficiently and effectively across the enterprise.

5. **Compliance:** The fall of Enron and the accounting scandals that ensued led directly to calls for more rigorous utility oversight and strict new reporting requirements, culminating in the now infamous Sarbanes-Oxley legislation as well as other changes to corporate governance on virtually every level. Clearly, implementation of these new policies and procedures has proven to be both complex and costly, but many integral parts of the compliance solution set are implicitly automation/IT-centric and simply cannot be satisfied by human assets alone.

6. **Reliability:** The August 14, 2003 Blackout had the immediate effect of leaving millions of homes and businesses in the Northeast without power for extended periods at a cost pegged in the billions of dollars. However, despite a protracted period of what seemed to be endless investigations and reports leading to little more than 'analysis paralysis', there were actually some tangible outcomes resulting from the outage. Key among them was the transition of NERC from the North American Electric Reliability Council – a loosely organized utility body with only a minimal mandate to police reliability and virtually no authority to impose meaningful penalties on violators – to what is now the North American Reliability Corporation, which the Federal Energy Regulatory Commission has given both the mandate and authority needed to tackle the job of electric reliability enhancement and enforcement.

7. Security: The 9-11 attacks and subsequent breaches of security (coupled also with fallout from the 2003 blackout) have caused utilities varying degrees of concern about the security of their operations and assets. During the past several years substantially all utility enterprises have had to not only re-think their operating strategies and how to best protect their assets in the event of another terrorist attack, but also how to safeguard their automation and IT systems from cyber-attacks, whether emanating from inside or outside the utilities' physical walls and network firewalls. Notably, the resources needed to address and overcome these challenges are daunting and will not be provided by instituting new security policies and procedures alone. Both physical and especially cyber-security will need a big helping hand from automation/IT if there is to be any hope of a truly secure future for utility enterprises.

While I'm sure I've missed a few details, I think it's safe to say that utilities have their work cut out for them and will need all the help the automation/IT supplier community has to offer. Indeed, all of the time, money and resources that have been poured into automation/IT over the past 50 years pales by comparison to what will be needed in the years ahead. However, while it might be discouraging and even more than a little intimidating to envision the massive challenges that are still ahead, it would be pure folly to think that we will see an intelligent grid emerge without substantially increasing the automation/IT infrastructure at all levels of utility operations.

So, even if your enterprise has invested in new technology recently, now is the time to reconsider the future and how you can best prepare for the formidable demands associated with implementation of an intelligent grid, demands that will be placed on utilities and suppliers alike. This isn't just the start of a new year, but rather the start of a new era: The age of the holistically integrated utility enterprise. And, if that sounds like a new concept, it was – yesterday. ■

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 co-founder and Director of Research & Consulting for InfoNetrix LLC, a New Orleans-based market inteligence 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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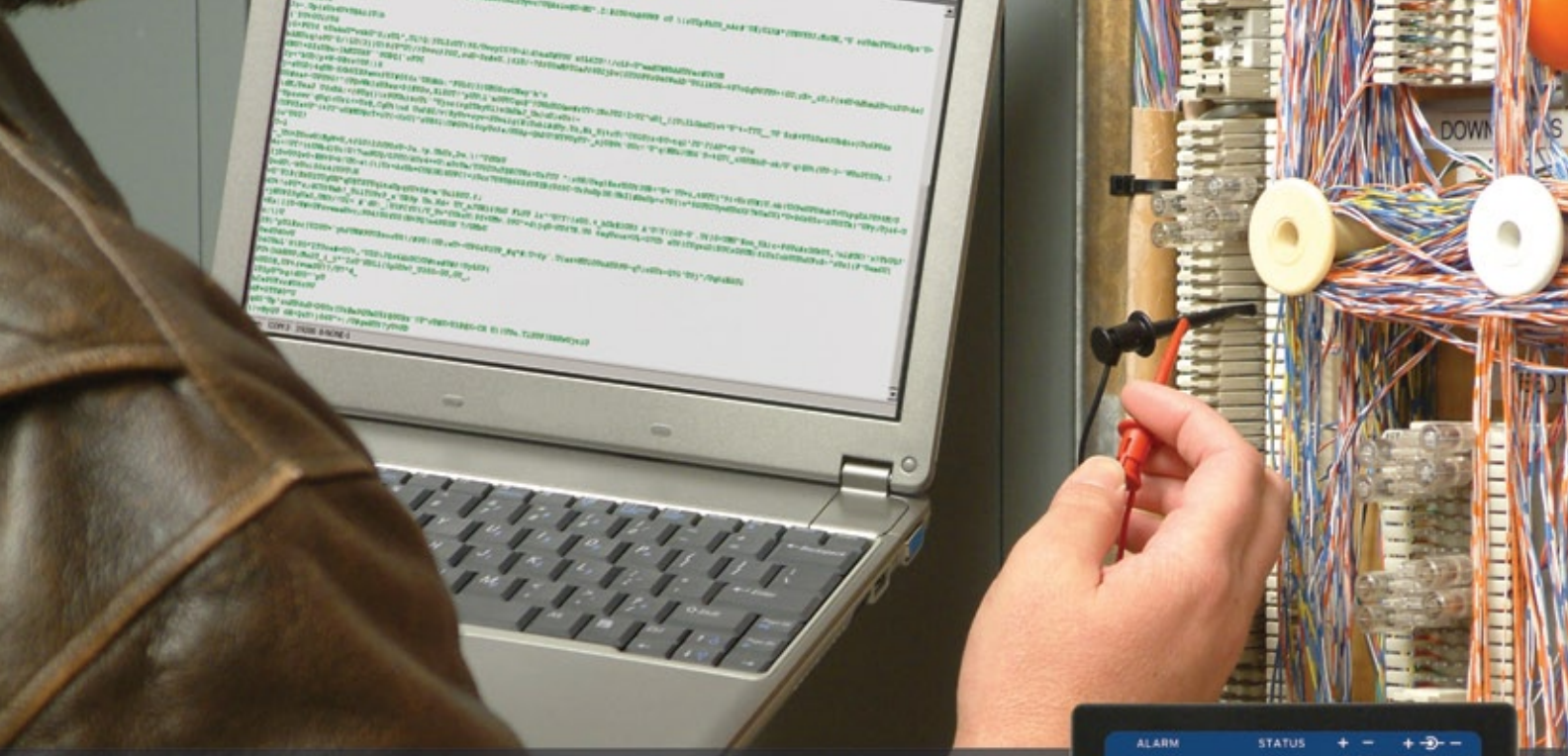

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The Role of AMI in the Integration of Demand Response into Ontario's Supply Mix

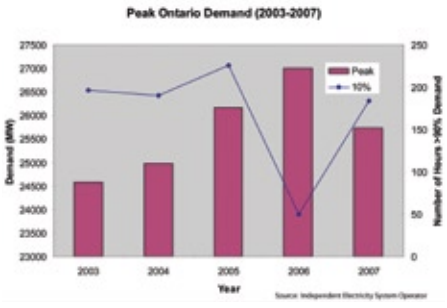
By Caroline Lofthouse, Communications Specialist for Rodan Energy & Metering Solutions

Ontario's electricity industry faces a number of challenges over the coming years. The growing concern about greenhouse gas emissions from coal-powered generation, and aging infrastructure that requires the replacement of 80% of its generation assets must be balanced against increasing electricity demand. The Ontario Power Authority (OPA), whose mandate is to ensure the long-term reliability of Ontario's electricity supply, released its Integrated Power System Plan (IPSP) this past summer. This plan proposes phasing out coal power (representing 18% of the current installed resources) and the near doubling of electricity generated from renewable sources.

Although once neglected, the consumer as a resource has become a critical component of managing Ontario's power supply. The OPA has set the ambitious goal of integrating 6300MW of Conservation and Demand Management (CDM) into the province's supply mix by 2025. The deregulation of Ontario's electricity market, the blackout of 2003, power warnings and air advisories have generated public awareness that electricity is a resource not to be taken for granted. This growing public consciousness of the environmental and economic consequences of electricity use has primed the market for CDM programs. This was demonstrated last August 2nd. The second day into a power advisory, the Independent Electricity System Operator (IESO) projected Ontario's demand to peak at 26,502MW. However, as a result of engaging the public through appeals to reduce electricity use and the implementation of various Demand Response (DR) programs, Ontario's demand reached a peak of just 25,584MW that day.

As the CDM market is established in Ontario, DR is quickly emerging as a flexible, real-time solution to securing Ontario's power supply during times of peak demand. Where conservation seeks to lower overall consumption, demand management through DR programs, reduces peak demand. By promoting a more efficient use of electricity resources, DR programs can help mitigate power supply issues and lower the price of electricity and in doing so, promote economic benefits.

DR can play a critical role in system planning. Ontario's peak demand of 27,005MW was recorded on August 1st, 2006, however demand exceeded 24,000MW for just 58 hours or 0.7% of that year. In comparison, the extreme hot weather conditions during summer 2005, saw the total demand for that year exceed 24,000MW for 154 hours or 1.8%. Through engaging consumers to reduce electricity usage during, for example, the top 100 hours, system planners can potentially reduce the peak demand by 5-10%. The OPA is set to do just that. Launching a suite of DR programs, the OPA has established a province-wide market to further integrate this resource into Ontario's power supply mix.



DR Benefits

By actively engaging demand-side modification, both market operators and participants provide numerous benefits to the province:

Capital Security

Reducing peak demand minimizes the requirements for more generation, transmission and distribution assets. The IPSP proposes a supply mix totaling approximately 35,000MW to meet Ontario's demand of 2025. Without the 6300MW of proposed CDM, an additional 4000MW of generation would need to be installed, requiring additional transmission and distribution assets to accommodate the increased grid capacity. Since peak demand often represents no more than 200 hours a year, this new infrastructure may very likely sit idle 95% of the time. By actively engaging consumers to conserve during times of peak demand, market planners and operators reduce the need for costly new infrastructure.

Supply Certainty

Declining capacity margins and the proposed transition to a 'greener' supply mix for Ontario present challenges to meeting the province's growing electricity demand. In fact in the most recent 18-Month Outlook published, the IESO clearly demonstrates the growing importance of CDM in keeping Ontario's lights on:

> ** "Under the normal weather scenario, sufficient resources will be available within Ontario to meet expected requirements during all but one week over the next year and a half. For this to occur, all of the planned resource additions must meet their stated in service targets and the aggressive conservation targets set by the Ontario Power Authority (OPA) must be achieved."*

* 18-MONTH OUTLOOK: An Assessment of the Reliability of the Ontario Electricity System From January 2008 to June 2009. Independent Electricity System Operator, Dec 17th, 2007

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DR is an integral component in CDM planning as it allows market operators to respond to system constraints in real-time. Where capacity margins fail to provide an adequate supply 'buffer', DR resources can quickly be dispatched to reduce demand to meet the available supply.

Furthermore, DR provides a needed flexibility as coal-power resources are replaced with renewable energy sources. As the province transitions to a greener supply mix and looks to replace aging infrastructure, DR is the most effective way to reduce electricity consumption on a short-term basis and support the province's green initiative.

Market Efficiency

Increased demand equals increased price in virtually any market. Price volatility in response to increased demand is commonplace in Ontario's electricity market. For example, record setting peak of 27,005MW on August 1st, 2006 saw prices rise from $112.17 in Hour 9 (24,443MW) to reach a maximum of $226.73 in Hour 12 (26, 712MW). This represents a doubling of price from an increased demand of just 2274MW. A similar scenario was observed the following day (Aug 2nd) when prices rose from $104.62 in Hour 9 (23,524MW) to reach a daily maximum of $317.76 in Hour 14 (25,816MW). In fact, on Aug 2nd the price doubled from $149.59 (Hour 13; 25,643MW) to $317.76 (Hour 14; 25,846MW) from an increased demand of only 173MW.

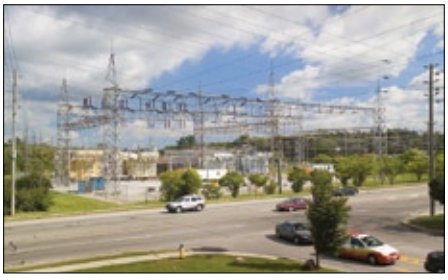
Price variability can be caused by either increased demand or supply-side constraints. In either case, a reduction in demand can help lower the wholesale market price. According to the Federal Energy Regulation Commission's 2007 report entitled Assessment of Demand Response & Metering, in the summer of 2006, DR activities actively reduced market prices. The Midwest Independent System Operator reported a reduction $100-200/Mwh in the market clearing prices with a DR curtailment of $2,650MW on August 1st. The following day, PJM reported that DR lowered energy prices by more than $300/MWH on the operator's record peak day.

Carbon Currency

As increasing pressure is put on governments to address the issue of human-induced global warming, much attention in Ontario is focused on closing the coal power plants. Ontario Power Generation, the organization charged with operating over 22,000MW of installed generation capacity in the province, reported 25,932,840 tonnes of carbon dioxide emissions resulting from the operation of Ontario's five coal-power generation stations in 2006.

The IPSP proposes the closing of all of Ontario's coal power plants by 2014. Consumer behaviour will be key to achieving this goal. DR provides energy consumers a platform on which to minimize their own carbon footprint and help phase-out coal from Ontario's supply mix. In addition, DR provides large energy consumers an opportunity to participate in emerging carbon-trading markets.

The DR market in Ontario is in its infancy. Existing programs target specific geographic areas or certain markets. The population growth in York Region, just north of Toronto, has outpaced its supply infrastructure resulting in the implementation of a number of DR programs. The IESO has the Emergency Load Reduction Program as a resource of 100MW+ to be dispatched during times of supply-side constraints.



This year the DR market is expected to become even more established through out the province with the release of a suite of DR programs from the OPA aimed at increasing grid system reliability and moderating market price. Through the role of load aggregators, the market will be open to all consumers of 50kW or greater. The OPA's DR3 Program provides the financial incentives necessary to develop and effective DR market in Ontario and makes load aggregation economically feasible.

This emerging market would be limited to only the largest energy consumers were it not for the province's Smart Meter and Meter Data Management and Repository (MDM/R) initiatives targeting residential and small commercial consumers. Enabling technologies and infrastructure are fundamental to the integration of DR resources in Ontario's power supply.

Advanced Metering Infrastructure

Effective measurement & verification of curtailment activity is largely dependent on Advanced Metering Infrastructure (AMI). Smart or interval meters record customers' consumption on an hourly basis, store and transmit this information over fixed networks for use by customers, utilities or grid operators. This allows timely retrieval of consumption for the purpose of verifying a directed DR event.

Until recently, generally only those customers using greater than 250,000 kWh/year had interval metering installed at their facility. In 2005, the Ontario government committed to the installation of smart meters for all customers by 2010. When this technology is in place, the customer, regardless of size, is provided the tools to modify consumption and respond to real-time pricing. Through the implementation of smart meters across the province, the consumer will quickly learn that when electricity is being used is as important as how much is used. DR initiatives can then easily be provided to residential & small business consumers.

Data collected through all Ontario smart meters will be forwarded to the province's MDM/R, which is then verified and downloaded to the utilities for billing purposes. The single location for data collection is advantageous in that it ensures the standardization of data, greatly increases accessibility and provides universal applicability of the information collected.

The implementation of AMI & MDM/R will open up the possibility of DR participation in Ontario over the coming years. Open access for third parties to the communications infrastructure and the meter data will greatly increase the ease with which electricity consumption is measured and demand reductions are verified. However, challenges remain both in planned infrastructure and DR market evolution. To fully realize the DR potential of Ontario consumers, technologies and DR program design needs to expand to ensure the Ontario's CDM targets are met.

Load Potential

The current implementation of AMI in Ontario is focused largely on residential loads. Without sufficient technology in place, it often is not economically feasible for small businesses to participate in DR programs as the cost of installing necessary metering would exceed the financial benefits offered.

Pulse Outputs

Smart meters installed provide hourly data, yet DR measurement and verification requirements put forth by the OPA for DR3 require 5-minute interval data. Such a requirement, without sufficient technology already in place, can make the aggregation of smaller loads cost prohibitive, thus excluding a large proportion of electricity consumers from participation. Also, daily uploads of data to the MDM/R limits real-time access for the end user requiring additional hardware for DR participation.

Communication

Two-way communication networks greatly increase DR capacity by enabling the grid operator or aggregator to control a participant's consumption and provide necessary price information to the consumer and in-home devices. For effective and reliable demand curtailment, it is highly beneficial for the program manager, aggregator and end user to be able to receive data and modify consumption remotely. Ontario's AMI currently limits communication and real-time access to usage data.

Stakeholder Cooperation

The success of Ontario's emerging DR market isn't limited to effective technological communication but also communication between the stakeholders. Distribution utilities play a key role as they are often first line of contact for the consumer. DR can greatly enhance a utility's CDM portfolio. By providing an additional service, it presents a customer relations opportunity from which both parties may benefit. Distribution utilities have an established relationship with the customer, own the metering infrastructure and the customer's load profile and thus have a vested interest in the DR participation of their customer.

Ontario Government agencies such as the OPA and the IESO enable the development of the DR market. Through program design and implementation, these regulators set the parameters and provide the incentives for end-user and third party participation. The customer and the aggregator are the critical pieces of the DR puzzle. For a DR market to successfully develop, no party can act as a silo. Cooperation and communication between these parties are essential. Each market player has a valuable role in its success.

Looking Beyond

AMI provides the framework for the evolution of a dynamic electricity grid by giving all consumers the necessary information to change their behaviour in response to pricing or reliability concerns. AMI is the key to integrating DR, Distributed Energy Systems, Consumer Energy Management Systems, Distributed Automation and Smart Appliances into Ontario's Smart Grid of the future. Design flexibility and ready access to information for future demand-side measures need to be considered now during the implementation of smart meters in the province.

In addition to technological advances in the market, DR can also be highly beneficial in market design. Competing with generation resources in the supply mix, DR provides an economic alternative to acquiring additional generation to meet demand. As seen in day-ahead markets in New York State, buying back load is just as effective as generating electricity when the market price is sufficient. Balancing supply and demand is no longer a one-way transaction.

The integration of DR resources into Ontario's power supply is a challenging but necessary step in meeting the province's growing electricity demand. The IESO projects demand growth of 1% per year on average. As the supply mix transitions to that proposed by the IPSP, consumers will have an increasing role in securing the power supply of the province. DR provides the incentives to the end user and needed flexibility in system planning to respond to real-time supply constraints.

The enabling technologies associated with AMI and MDM/R are just the first step in developing Ontario's DR market. As a relatively new concept to the province's consumers, an effective educational campaign is required to introduce DR and the benefits to all consumers. By providing the tools to the consumer, whether in the form of technology or information, system planners empower the consumer with the ability to make a difference. ■

About the Author

Caroline Lofthouse *is the Communications Specialist for Rodan Energy & Metering Solutions located in Missisauga, Ontario. As a Metering Services Provider licensed with the IESO, Rodan provides high voltage metering and power systems engineering services as well as a full suite of sub-metering, data management and settlement solutions. Under its EnerShift brand, Rodan has become the leading provider of demand response and energy efficiency aggregation services in Ontario. Caroline joined Rodan in 2006 upon completion of a M.Sc. from York University in Toronto, ON.*

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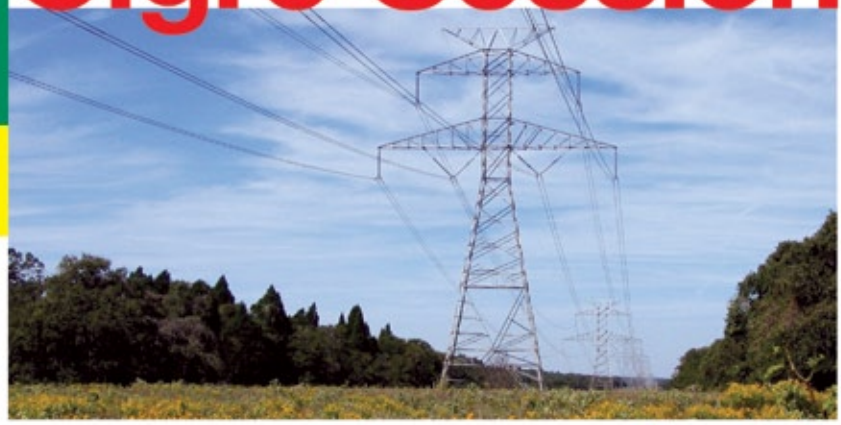

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Robert Sill, CEO/President

The 2008 Automation/IT Leadership Series

By Michael A. Marullo, Automation/IT Editor

Aegis Technologies Inc.

By Robert Sill, CEO/President and
Andrew Bartels, Chief Technology Officer/SVP

Andrew Bartels,
Chief Technology Officer/SVP

From the Publisher:

Welcome to the 2008 Automation/IT Leadership Series! Because there have been so many positive comments about this feature since it was introduced in 2007, it will again be a part of our editorial line-up for 2008. We have planned an exciting slate of interviews for the upcoming issues and look forward to hearing your feedback on this and/or other content throughout the coming year.
– Steven Desrochers, Publisher

Michael A. Marullo
Automation/IT Editor

As many of you know, I've been on the record for a long time as a believer that true market leadership comprises many important attributes that go well beyond sheer size, sales volume, geographical presence or business acumen. Indeed, technological leadership – another very important leadership quality – sometimes originates in less conspicuous corners of the marketplace. After all, it wasn't so very long ago that a little company developing a disk operating system for personal computers quietly became a modern-day "David" that would eventually take down more than one "Goliath" of the global computer industry.

Today, the electric utility industry is faced with the daunting task of reinventing itself from a business standpoint as well as from a technological perspective. Addressing the challenges and providing suitable, yet economical solutions will require a new wave of creativity and innovation, much of which will predictably come from those well-established, high-profile companies that we can all readily identify. However, some of it will come from less conspicuous sources. Any of these companies could arguably become the next Microsoft, but we won't know for sure until it happens – if it happens. Meanwhile, it pays to remain vigilant!

For 2008, our Automation/Leadership Series will provide ongoing insights into the ideas, concepts, innovations and plans of both traditional and emerging leaders in the months ahead. Over the next few years, the entire utility industry will need to rethink automation in a far more pragmatic and urgent manner than has been typical in the past. At the same time, we feel it is prudent to broaden our perspective to consider bold alternatives and even unconventional solutions emanating from new and increasingly diverse sources.

Consistent with that view, our first interview of this new year is with Aegis Technologies, a Phoenix-based company. Aegis CEO, Robert Sill, and Andrew Bartels, the company's CTO, bring a fresh perspective to the series in a candid exchange that focuses on some of the most onerous challenges of our times.

– Mike Marullo, Automation/IT Editor

EET&D: Since Aegis Technologies is a relatively young company and perhaps not a familiar name to some of our readers, perhaps a little background would be helpful as a backdrop for our discussion today. What was the genesis of the company, and how does its mission/vision relate to electric utilities?

Sill: Aegis Technologies was founded in 2002 as a direct result of the 9/11 terrorist attacks. We initially set out to create specific hardware/software solutions to protect the control systems that run U.S. industries. However, in our development process, we found that many organizations – utilities in particular – were already struggling with higher demands on their aging legacy control systems, and they were unable to assume the expense of costly security upgrades that did nothing to improve performance or margins.

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So, we decided to broaden our focus to also address these compelling problems, which are among the most serious challenges to maintaining safe, secure and reliable electric power networks around the world.

EET&D: I understand that you and Andrew, as well as some of your colleagues originally came from other industry segments. Which parts of that background do you feel are relevant for the utility sector?

Sill: Yes, Andrew and I both have an extensive background in financial systems – as do some of the others on our staff. Other than military applications, the financial world is arguably the longest standing and most rigorously tested commercial/industrial environment when it comes to security and related protective measures. Although we do recognize that the problems and solutions are somewhat different in the utility sector there is still a great deal of relevancy, especially as related to the technologies employed. For those who think that cyber-security is somehow uniquely a utility issue or that technology from other industries can't transfer to utility systems effectively, I want to say that with time and the help of educational forums like this one, I'm confident that we will eventually dispel that notion and get on with dealing directly with the problems at hand.

EET&D: Robert, I know that my own impressions of Aegis prior to this interview were that it was mainly a cyber-security company, but now having done some research of my own, I see that you actually go well beyond the security dimension. Perhaps you'd like to elaborate on that some for our readers?

Sill: Sure, let me address that from a general business standpoint and then let Andrew add his views on a more technical level. Besides allowing utilities to meet NERC security recommendations before they become mandatory, our solutions also extend the life of legacy systems; delay the need for costly equipment replacement; improve speed, efficiency and diagnostics; retrofit seamlessly into existing control systems; and easily upgrade to protect a utility's business and customers. Add-on applications are currently in development to further enhance performance and meet our customers' changing needs.

Bartels: Yes, we've taken a unique approach to our technology design and architecture. It's extremely modular and flexible, allowing us to bring non-security related business benefits in addition to those directly addressing the security issues. We've heard from many utilities that they would like to enhance the security of their systems, but simply cannot find the funds to do that. The monetary benefits brought by this combined approach are directly measurable and easily offset the real and perceived costs for adding security separately.

EET&D: We all know the rudiments of automation and IT for electric utilities – SCADA, GIS, CIS, outage management, metering, and so forth – but this time around there are some new dimensions to the equation. Indeed, the intertwined issues of security, declining infrastructure and an aging workforce will be at the heart of many if not most automation/IT discussions for a long time to come. Faced with these formidable new challenges, where does Aegis Technologies fit into addressing and helping overcome them?

Sill: Obviously there are no simple answers here, but let me try to address these one at a time from a high-level standpoint. Andrew might like to add some technical perspectives on these topics as well. I'll address security first, since that is an area where Aegis has considerable knowledge and experience and also where a substantial portion of our development has been and will continue to be targeted.

An average-sized utility will typically experience thousands of attempted hacks into their control systems every month, and that trend is on the rise. During the past few years, there have been over 80 confirmed cases of successful cyber-attacks resulting in temporary loss of services, equipment damage and substantial economic loss. While the crippling August 2003 blackout in the northeastern U.S. has NOT been publicly attributed to purposeful hacking, its occurrence dramatizes the worrisome reality that even minor disruptions can quickly cascade into serious failures.

Moreover, with the operations of most utilities increasingly tied to the Internet, these disruptions to control systems could come from virtually anywhere in the world. And since much of the equipment utilities use – particularly in mission-critical applications – is similar worldwide, virtually anyone with even a cursory knowledge of computers and communications can figure out how to manipulate the U.S. power grid hardware and software for purposes ranging from mischief to cyber-terrorism.

Bartels: Clearly, solution providers have an implicit mandate to identify and mitigate security risks in new systems going out the door and to ensure that their systems conform to the evolving security standards. However, we cannot afford to ignore the thousands of installations that represent the present backbone of grid monitoring and control while we work toward preventative measures for the future. Likewise, we must continue to invest in preventive measures so that we don't keep perpetuating the problems.

Most control systems used today were not originally designed to defend against cyber attack. Moreover, the events of 9/11 increased the awareness to the inherent vulnerabilities of control systems connected to the Internet and remote telephone connections.

For these and other reasons, Aegis has dedicated itself to dealing with security in both the past and present tenses because we saw early on that there are both contemporary and legacy security issues in need of attention. In the first case, security protection must be designed in, and in the latter case it must be bolted on, so to speak. Our approach is to address both cases in the proper context and with the proper tools for the job.

EET&D: The recent passage of the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) guidelines is considered by many to be an important step in a long process of trying to ensure our nation's energy sources are protected, but more still needs to be done if we want to keep the lights on. What are some of your thoughts regarding the relationship between this new regulatory intensity and what can be done to address these increasingly rigorous and potentially expensive directives?

Sill: The NERC CIP 002-009 Reliability Standards provide a framework for identifying and protecting critical cyber assets essential to the reliable operation of the nation's bulk power system. They establish minimum requirements and use specific measures to determine compliance to each of the standards. Compliance will be based on meeting these requirements through a formal audit process. The multi-year implementation schedule requires that responsible entities be auditably compliant by the end of the second quarter of 2010, or by December 31, 2010, in certain cases dependent upon the classification of the responsible entity.

Aegis is staffed with people who are pioneers in cyber-security. We helped the banking industry establish and maintain what are among the highest standards of cyber-security for its vital businesses. Now, we are doing the same for the utility industry and for other connected segments of America's infrastructure, including oil and gas, transportation, telecommunications, water resources – virtually any part of America's economy that depends on power, or on which the power grid depends.

Bartels: I'm sure that some people will rightly question the relevancy of cyber-security standards in the banking industry for the utility sector, so I want to make clear up front that it is certainly a legitimate question to ask. However, we are talking about applying subject matter knowledge, proven techniques and technical expertise; we are not suggesting that utilities should accept products or other solution sets specifically designed to address problems in a different industry and/or use them in applications for which they were never intended.

Aegis has invested considerable time, money and resources in developing products designed specifically for the energy and utility marketplace. These are not just transplants from an unrelated business or technical environment. Although the resulting solutions exhibit many of the same features and benefits, we provide market- and application-specific solutions. Our Odyssey™ Product Series, for example, is specifically designed to help responsible entities achieve NERC CIP compliance by providing comprehensive, point-to-point security for the control system's electronic perimeter while also improving overall system performance, whether the system is new or old.

EET&D: What about the declining infrastructure issue; how does that tie into what Aegis brings to the party beyond traditional security appliances?

Sill: We also recognized a similar duality with respect to T&D infrastructure decline; that is, there are both new and legacy dimensions to upgrading – and over time, replacing – the vast utility asset base to accommodate the rapidly increasing demands that will be placed on those assets over the next several decades. This complex set of challenges will have to be addressed incrementally and carefully planned to prevent any disruptions while the transition is under way.

Meeting the challenge will also require a very delicate balance since we will have to contend with large numbers of assets reaching the end of their useful life expectancy simultaneously, right along with the automation/IT systems that monitor and control those assets. By taking steps to alleviate the dual pressures of functional obsolescence and security compliance, we can buy the time that will be needed to address and solve these problems with more comprehensive, longer-term solutions.

EET&D: What are some of the specific aspects of what I'd call a repair-or-replace problem, and how do you see your role in making sure that these formidable challenges will be met?

Sill: Most utilities are already faced with huge deferred maintenance costs in addition to the need for upgrades and replacements of their automation/IT infrastructure. It would be nice to just replace everything with state-of-the-art equipment, but I think we can safely say that is simply not going to happen, both for cost and various other reasons.

Faced with this reality, utilities must find ways to extend the useful life of these systems along with those of the assets they are charged with managing and protecting. In many cases, this will require tools that have not existed in the past. Aegis is a company that is dedicated to designing, developing and making those tools available to whomever may need them. We are not a systems supplier, but by working closely with automation/IT suppliers, system integrators and of course, the utilities themselves, we will be well positioned to do much of the heavy lifting needed to keep the grid up and running throughout the long transition period that lies ahead.

EET&D: Before we leave the infrastructure issues, legacy automation/IT systems are one area that probably deserves a lot more attention than it gets. So much of the security emphasis we hear and read about today is focused on the certification and compliance of new systems, yet there are thousands of existing installations that are functionally obsolete, not secure or both. What are your views on this situation and what do you feel can be done to help alleviate the inherent risks associated with legacy installations?

Bartels: Aegis Technologies has developed a solution that provides unprecedented security for low-speed serial communication lines like those found in legacy control systems. Contrary to the belief that it is impossible to securely encrypt data over low-speed serial communication without adversely impacting operations, Aegis' technology encrypts data at a robust 2048-bit encryption level without adding latency to existing networks. But there's also another issue I'd like to mention here that I think is worth bringing to light.

For whatever reason there seems to be a widely held – though perhaps not a consciously cultivated – view that when it comes to security, every company in the automation/IT business is assumed to have

the requisite knowledge and experience to create an appropriate security environment for virtually any system or application. While most people readily acknowledge that the skills, experience and knowledge required to create an energy management system are different from those needed to design an outage management system, for some reason security is all too often relegated to garden-variety status.

What I want to clarify is that security challenges are best served by a combination of technological skills and application knowledge. These skills and knowledge are not necessarily present in every organization, so there is a definitive need for security specialists, especially considering the downside of failure to address and solve the technical problems whose existence is widely acknowledged by users, suppliers and regulators alike. Even the best-educated and skilled heart surgeon will probably fall short when it comes to brain surgery, so I think it follows that applying that same logic to solving security problems is dangerous at best.

EET&D: Last, but certainly not least, there is the aging workforce issue. Literally thousands of years of knowledge and experience will walk out the door of utilities over the next decade, and once gone they will be difficult – in many cases impossible – to replace in like kind. So, what many have agreed is one measure we can take to offset the impact of this loss is to extend the useful life of the assets that these industry veterans designed, built and maintained until we can capture that brain trust or replace the assets with more contemporary versions. How do you see this problem being addressed, and what role will Aegis play in the solution?

Sill: The simple fact is that there are fewer people entering the engineering field just at the time when they are needed most. And, as the existing workforce continues to retire in the future, the industry will be forced to operate with even fewer employees and will clearly require technology to fill the gap created by the net loss of talent. Put another way, the workload doesn't diminish when employees retire. Our solution set addresses this issue by adding time and labor-saving centralized troubleshooting benefits that are designed to obviate the need for 'rolling a truck' to the substation to diagnose communications issues. Additionally, the compression feature allows more data to be transferred without interfering with vital control communications. Both the troubleshooting and compression features translate into time and money savings for the customer by allowing more automation of and fewer trips to the substation.

EET&D: Well, unfortunately I think we can all agree that there are plenty of problems to be solved and certainly an overwhelming need for the kind of solutions that Aegis was established to provide. I'm personally gratified to see that there are companies like yours bringing specialized expertise and experience that will help us all deal with the enormous tasks that lie ahead. And, I'm sure that our readers appreciate learning about how existing automation/IT investments can be secured and protected until next generation solutions can be put into place. In my opinion, 2008 marks a new beginning in automation, and I feel certain that your contributions will not go unnoticed. Thank you for sharing your time and thoughts with us. ■

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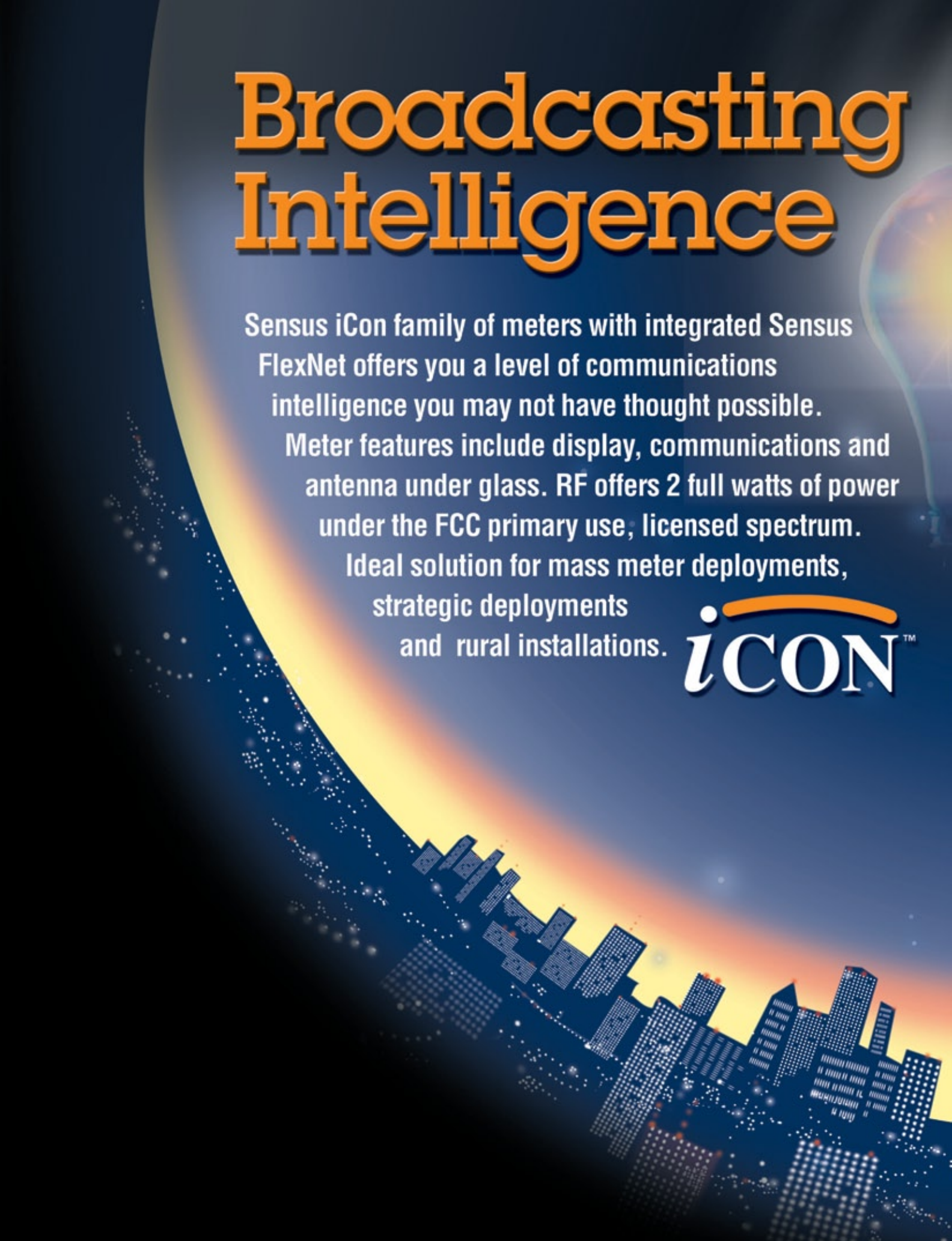
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The Dual Threat: Aging Infrastructure and Aging Workforce Call For Integrated Asset and Workforce Management

By Steven A. Radice, Vice-President, Utility Solutions, Ventyx

Few people in the utility transmission and distribution business need convincing that the above- and below-ground asset infrastructure – be it electric, gas or water – is a critical component that is today showing unmistakable signs of age. And, most utility managers understand that the field workforce tending to that infrastructure is also aging and retiring at an increasing rate. These issues of aging infrastructure and aging workforce are often examined independently in articles, papers and presentations to industry forums. Although richly worthy of attention in their own right, it is the interaction of the two, the dual threat of asset infrastructure aging simultaneously with the workforce maintaining it, that should be a particular concern of utility management, regulators, employees and customers. This article describes components and ramifications of each of the aging challenges and discusses the technology solutions that are evolving to meet those challenges independently and, more importantly, together in an integrated manner.

When a utility field technician or crew is dispatched to complete a series of inspections and maintenance orders at, for example, a substation, one can assume that they are experienced and fully trained to do so. With the median age of utility industry employees currently at 49, this would certainly be a valid assumption. Indeed, for the utility industry, there is a large group of well-experienced, well-trained current employees in the 45- to 54-year-old range. In executing the various procedures and tests involved in inspections and maintenance work, these employees are drawing directly on the considerable expertise and familiarity with the assets they have developed over some 25 years of work in the field.

Although inspections and maintenance procedures are well documented in many cases and the subject of frequent refresher training for crews, the personal knowledge component is just as important. Knowing the peculiarities of a given asset type – even down to the model number – is a valuable additional aid to properly conducting an inspection and, if necessary, making repairs. As these lead technicians and crew chiefs age, however, an increasing number are taking advantage of utility retirement packages in order to leave on or, in some cases, before their scheduled retirement dates. When such individuals leave, that individualized knowledge goes with them. And, with strict cost controls in place at most utilities, hiring replacements is a lengthy and demanding process. Even once hired, the time needed to achieve the same level of personal knowledge is measured in many years, not months. With the increasing use of contractors (also exposed to the aging workforce factor), utilities might not even be in a position to hire new employees who will eventually be developing the in-depth skills needed for field work.

So, when a relatively new lead technician or crew goes out next year to do that same inspection series at a substation, the personal expertise brought out to the job with them may be significantly lower than in prior years. No doubt they will exert their best efforts, will follow documented procedures, and be subject to on-site personal review by a field supervisor. But that innate ability to sense what the status really is for a given piece of the asset infrastructure will be lessened.

At the same time as this aging workforce factor is coming into play, those same assets and infrastructure being maintained are also aging, thus requiring more and lengthier inspections and maintenance procedures and, in some cases, replacement. Newspaper headlines and TV news stories the last five years have all too often featured a failure, sometimes spectacular, of a given piece of electric, gas or water infrastructure that at the very least led to service interruptions or, more dramatically, produced significant damage and human injury as a result of its failure. Much of that infrastructure is composed of operating assets that utilities of all types must continually inspect, maintain and replace to ensure reliable performance. And, while a good portion of the nation's utility asset infrastructure is in satisfactory condition, an increasing percentage of it is nearing (or exceeding) its planned operating life and therefore requiring field work to maintain or replace it. In such work, utility employee personal knowledge of individual assets as well as the overall transmission and distribution network is critical.

Faced with this impending crisis, how should energy and utility companies respond? There are two major components to the solution:

1. Capture procedures in real time as they are performed in the field.
2. Break down the technology silos between asset and workforce management.

Real-Time Data Capture Key to Continuous Improvement

Before information such as procedural processes, planned vs. actual work, equipment change-outs, etc., can be shared, it must first be captured. And, a retiring technician can not be expected to outline effective procedures developed over 25-30 years of experience in return for a gold watch at his retirement party. Therefore, it is critical that utilities empower their technicians with the ability to document procedures as they are performed – and modified – in the field. The best vehicle for this activity is a Web-enabled mobile device (e.g., Blackberry, Smartphone, laptop, etc.) backed by a robust mobile platform.

Technicians empowered with such mobile devices not only have a wealth of beneficial information at their fingertips (more on this later). They can also capture vital data which can help future technicians perform the same work more efficiently. For example, a technician dispatched to replace a breaker at a substation may note that the instructions detail a procedure which is not the optimum method based on a recent experience with the same breaker. Therefore, he can adjust the procedure on the fly and capture that information for use by other technicians and crews across the utility, as well as third-party contractors – regardless of their level of experience. In this way, not only is a single technician continuing to improve his effectiveness; he is also helping to implement continuous improvement across the enterprise.

The information, once captured, is typically stored in an enterprise asset management (EAM) system which serves as the "system of record" for the assets and the work performed against them. By tightly integrating the technician's mobile device with the EAM and other enterprise systems via a robust mobile platform, the technician can close work orders at the time the work is completed and have that change reflected across the enterprise. As a result, the status of the assets, bills of materials, parts inventory, and other data are updated in real time so that the rest of the enterprise has access to accurate information regarding the asset.

Integrated Systems Break Down the Silos

Another key ingredient to dealing with the aforementioned "dual threat" is sharing the information once it's captured. This can be a real challenge since the work described above is typically generated in some form of utility asset management or work management system. Such a system consists of technology, certainly, as well as business processes, procedures and even accounting practices, all of which come into play in operating a satisfactory asset management program. For many years, such systems were "siloed" by the type of asset being installed or maintained; thus, all meters would be managed by one system (often a spreadsheet), all transformers and related substation equipment managed in another, and so on. In the last five years, however, there has been an increasing trend toward maintaining the history of all assets in a single enterprise-wide asset management system of record.

Ironically, this same silo approach also has applied to the utility field workforce, with meter and customer service personnel managed by one workforce management system, distribution personnel in another, and outage technicians in still a third. Like asset management, however, the trend in recent years has been toward a common workforce management system covering the entire enterprise field force. With both of these consolidation trends, therefore, the ability has arisen to take a more holistic and integrated approach to asset management and workforce management, both as separate disciplines but now also as a useful synergistic point of operational excellence. Nowhere is this outcome more helpful than in addressing the problems posed by an asset infrastructure aging as fast as the workforce that maintains it.

How would such synergy appear in a normal field environment? Let us use the example from above of a technician or crew going out to a substation for a series of inspection and maintenance tasks or orders. The very composition of the crew is a good starting point, in that the enterprise workforce management system would have facilitated the creation of a crew with the most appropriate skills to the orders at hand, and structured the assignment and scheduling of the work to achieve maximum efficiency.

The orders to be accomplished would be generated by the EAM system, using a variety of triggers (time- and condition-based in addition to regulatory requirements) to determine the specific asset items to be inspected and maintained. These orders would be passed electronically to a mobile data terminal (MDT) carried by the technician or crew. On its screen would be details of the orders and assets, giving the utility employees a clear view of what needed to be done, but not how. In the past, the question of how would have been left to the combination of training and personal knowledge that we assume exists today in most utilities. But with the aging workforce and asset infrastructure issue, the "how" may not be as clear today and in the future as a utility would prefer.

Here we can see the new abilities and benefits of an integrated approach to asset management and workforce management. In this scenario, besides passing down the order details, the upstream system would also send to the MDT a hyperlink or a file attachment for viewing by the technician or crew. The hyperlink would be a clickable reference to the specific detailed inspection and maintenance procedure for that asset, which would be resident on the device hard drive.

If wireless communications were available, one would see an internal Web site where details on the procedure were presented. Besides text information, the hyperlink can also provide graphical guidance, with detailed schematics of a given asset model, for example. Using the MDT's zoom-in capability, the technician can see the diagram in great detail as needed. The technician thus has at his or her fingertips specific and always up-to-date guidance on how to achieve the work order objective in detail.

Whereas a hyperlink reference would be largely generic to a group of similar assets, another possibility which is even more specific is the attachments capability. In this case, detailed information relevant to that particular asset and order, such as a digital photograph taken yesterday by the previous crew working on it, would be made available on the MDT.

Any changes made that day can be captured via another digital photograph and sent back up as a file attachment as part of the order completion process. The difference between hyperlinks and attachments in this example, therefore, is largely one of specificity to the asset and order in question.

Another possibility would relate to a maintenance procedure (such as replacement of an asset grouping) which a crew might need to undertake following an inspection. Using software on the MDT and the wireless capability, the crew would be able to interface to other third-party applications that are resident on the device itself or accessible via the Web. For example, compatible units (CU) are a major component of new construction for the maintenance replacement of assets. With this third-party reference tool, the crew can access a library of available compatible units for the order in question, and determine what materials and labor should ideally be expended in the procedure. Whereas in the past this information would be on paper and well known to experienced utility or contractor employees, with this capability they can easily and quickly reference compatible unit definitions that are always up to date and complete.

Summary

As you can see, numerous benefits are achieved by capturing asset and work information in the field and breaking down the silos between work and asset management. Useful information is made accessible at the place and time where it is most needed to properly perform the work, certainly a tool and capability previously impossible. This tool, as a result, greatly helps augment the personal familiarity of the utility workers on the job with the asset and work to be done. The foregoing are but two examples of where a properly thought out and integrated solution architecture approach can greatly assist a utility in its daily work as well as meeting its long-range objectives of reliability. The overall capability, achieved only through a complete solution which incorporates a robust mobile capability as well as proper integration and coordination of enterprise asset management and enterprise workforce management, thus can play an instrumental role in helping utilities deal with the dual threats of aging infrastructure and aging workforce. ■

About the Author

Steven Radice *is a Ventyx Vice-President for Utility Industry Solutions, with over 20 years experience and expertise in utility industry technology for the distribution business. He supports Ventyx account executives in shaping and selling enterprise technology solutions to meet the functional and technical requirements of utility customers.*

Prior to Ventyx, Mr. Radice was Executive Consultant for SchlumbergerSema, where he worked with national and international utilities on implementing distribution system solutions. Mr. Radice was Vice President of Product Marketing at Utility Partners, a utility industry mobile software firm, and held Consulting Manager positions at Price Waterhouse and Deloitte. He also served as CIO at a large financial institution in the Southeast U.S.

Making Substations More Intelligent by Design

PART ONE: Rudiments of Planning, Preparation & Design

By Craig M. Preuss, Engineering Manager-Utility Automation, Black & Veatch Corporation

Introduction

Utility substation integration programs have continued to grow since the 1990s. Although most utilities claim to have substation integration at some level, some have simply continued to install electromechanical relays and RTUs. Others have created one or more pilot projects with varying success to prove out new substation technology that is rapidly changing. Still other utilities have developed multi-year integration programs into second, third, and even fourth generations, rolling out multiple substation integration schemes across a large number of substations.

While much attention has been given to the potential costs, benefits, and architectures of substation integration technologies, little focus has been given to "how" a business case and new design is developed. With technology changing at an unprecedented rate just as many of the most experienced engineers have retired or are preparing to leave the workforce, even utilities with decades of experience in substation integration may encounter difficulties planning, developing and implementing substation projects that properly fit their current - and especially their future - technical, organizational and operational needs.

This two-part article will address the engineering standards, processes and best practices for substation integration and answer many of the most common questions as well as some more subtle aspects of intelligent substation planning, preparation and design. For example, what are the front-end engineering processes that result in the dramatic transformation of a blank sheet of paper and a good idea into the wiring, schematics, elevations, point lists, and test procedures that result in a successful project? What are the steps required? What are the issues and considerations in planning for the implementation? What are the potential risks and pitfalls? Can those risks and pitfalls be mitigated or avoided entirely?

This first part of the article outlines the standards and frames the engineering process. In part two, we will illustrate how Black & Veatch implemented this engineering process in a case study fashion, demonstrating the issues and implications of substation integration in an actual utility project.

Drawing a Blank

Substation integration isn't a defined product or service. So when you're starting with a blank sheet of paper, how do you draw integration and automation? How is it possible to transform a traditional substation design with control switches, panel mimic buses, RTUs, interposing relays and transducers into an intelligent substation?

The upcoming revision to IEEE standard C37.1[1], otherwise known as "The SCADA Standard," loosely defines an iterative process that is used to accomplish substation integration, or the connecting of IEDs together using one or more communication networks to distribute RTU functionality and enable automation. Notably, this process is not part of IEC 61850 "Communication Networks and Systems in Substations." However, the draft of IEEE C37.1 presents these steps:

1. Define near-term and long-term system functionality (system requirements)
2. Select the protocol(s) (both inside and outside the substation)
3. Select the IEDs
4. Select the system architecture
5. Secure the system
6. Define performance requirements

Each step depends on the others, which makes the process iterative. System functionality impacts IED selection, which can impact the architecture and even make your system vulnerable to cyber attacks if such risks are not taken into account at the outset. System performance requirements can also impact system architecture, which in turn, can impact protocol selection. These are just a few examples of how the process becomes iterative.

These steps may occur in a different order than shown above. IED selection typically comes first, primarily because relays and meters already exist, allowing the electrical system to be protected and measured. Thus, we often find that the paper is perhaps not as blank as originally perceived. That is, some IEDs may have already been selected, and a certain degree of system functionality is most likely desired.

[1] "Standard for SCADA and Automation Systems"

There may also be some pre-existing ideas and preferences for what protocols will be selected/supported and what general security requirements need to be applied.

In today's utility market, many utilities are seeking to move the substation design from a mix of electromechanical and microprocessor relays with no uniform backbone communications architecture to an integrated substation that supports automation implementations easily and economically. From a design standpoint, it would be nice to start from scratch, but in reality, most utilities don't have that luxury.

Many utilities are already extending their corporate WAN (Wide Area Network) to their substations, so they want Ethernet; but specifically how does one bring Ethernet into the substations? Other utilities may have equipment preferences for key elements (e.g., protective relays) because they already have a certain type of equipment in place; but what is the best way to select a protocol? Utilities know that a substation is a harsh environment requiring equipment compliant to IEEE Standard 1613[2] and IEC 61850[3]; but what else is required to protect these substantial investments of time, money and other resources in addition to the equipment itself? These are but a few of the many questions that any substation integration project manager must be prepared to answer.

Substation Integration

Getting started might sound easy, but from the start, utility personnel must be familiar with the concepts and issues in order to make the process smoother. How do you get experienced personnel who intimately know SCADA masters and IT networks to also understand substations with their protection and control schemes, RTUs, transformers, breakers, capacitor banks, and switches, let alone understand substation integration and automation? And what about the other way around? How do you get those intimately familiar with the substation site and environment to understand the greater SCADA and IT network issues? Black & Veatch recommends substation integration training in these situations to introduce utility personnel from across the enterprise to the equipment, concepts, issues, justification, costs, risks, benefits, and process of substation integration. Inviting everyone to the table is usually not possible, but representation from key business and operational departments is essential.

Functional Requirements

A series of meetings and supporting discussions are usually necessary to determine the system functional requirements. These requirements may be driven by a variety of technical and organizational needs, but will almost certainly include those defined in IEEE Standard C37.1. These include I/O, protection, ancillary services, time synchronism and programmed logic functions. Typical examples of technical performance criteria from IEEE Standard C37.1 are requirements for:

- Update Periodicity
- Latency (Seconds)
- Time skew (Seconds)
- Accuracy
- Resolution (%)
- Availability (Hours/month)

Solution Components

The solution components are selected specifically for the best possible combination of cost, flexibility and applicability to the substation environment; a brief discussion of this selection process follows.

Input/Output (I/O) and Measurements

The I/O (input-output) scheme is broken down into measurements, status, and control. By defining an I/O scheme that shows where the data sources are for the substation devices, several issues within each category can be discovered and resolved.

With regard to measurements, on the transmission and distribution side the accuracy of metering from relays can be an important consideration. The number and type of meters and the metering data needed are also important, along with consideration of backup sources. In addition to these standard metering quantities, some examples of other analog quantities to be gathered from the substation might include transformer LTC (Load Tap Changer) controller, battery charger (battery DC voltage), control house temperature, transformer DGA (dissolved gas analysis) and transformer temperature monitor (winding temperature).

A large number of SCADA device status points are usually envisioned as well. These might include selected relay targets and IED, communications and security status points. Several IEDs (i.e., primary and backup relays) can provide the status of breakers. A relay can be out of service for a variety of reasons while the breaker is still in service or requires operation.

[2] "IEEE Standard Environmental and Testing Requirements for Communications Networking Devices in Electric Power Substations"
[3] "Communication Networks & Systems in Substations"

Combinational logic can be used to create a voting scheme that has a high reliability of reporting the actual state. However, this approach results in making the system more complex and can be avoided by using distributed I/O wired directly to the breaker status contacts along with the breaker alarms.

Protection and Control

Control of substation devices is typically assigned to the primary and backup relays. More complex designs will assign SCADA control to the primary relays and HMI (human-machine interface) control to the backup relays. In addition, there is usually a desire to have a manual backup and "SCADA-disable" functionality in the control house. For substation control, dedicated distributed I/O can also be used when control would otherwise be lost whenever the relays are out of service. Distributed I/O devices are very common in the industrial world, but these industrial devices can have problems with temperature, power, and communication port ratings, depending on the suppliers and products selected. In recent years, several vendors have introduced distributed I/O devices designed to mitigate these problems.

Protective functions remain in the relays with traditional hardwiring of protective control outputs and inputs. The anticipated use or future migration to IEC 61850 will provide the capability for high-speed protection using the substation LAN, an important consideration in defining the system architecture.

Time Synchronization and Programmed Logic

Time synchronization is important because during catastrophic events it is best to have as much synchronized data as possible to help speed up and optimize data analysis and event correlation. IEDs should be time synchronized using the most accurate method supported by each IED.

Programmed logic is the basis for most substation automation. Each type of IED usually supports native programmed logic associated with the I/O for each device or device class. In order to support system-wide functionality, a high-speed peer-to-peer network is required. While IEC 61850 supports this requirement using high-speed messages with guaranteed performance, DNP3 can also be used over Ethernet for non-protective functions. This could be accomplished by IEDs broadcasting data to multiple masters or multiple masters polling the same slaves. Because this testing of programmed logic can be a significant issue during commissioning, ample time must be allocated in advance to ensure proper operation.

Ancillary Services and Security

Ancillary services are those services left over from the previous discussion; i.e., IED configuration, file transfer, log and data capture and diagnostic observation. Support for these services requires a high-speed network that supports more than two simultaneous connections. Performance can be improved by prioritizing these services; thus, limiting bandwidth usage by lower priority tasks (i.e., given that IEDs by themselves generally do not support prioritization).

Achieving data security in today's environment must adequately address evolving NERC CIP requirements. Security strategies for both physical and data security will drive approaches for security in substation integration. Requirements here may include monitoring of existing physical security systems in place and the flexibility to integrate future systems, as well as strategies for network and data separation from the corporate network.

IEDs, Architecture & Protocol Selections

Often utilities will already have an idea of which vendor(s) will supply the IEDs even before system design begins. Yet even in those situations, reviewing IED selections can be a time-consuming process because there are so many types and suppliers of IEDs available for the broad range of applications in the substation. (The IED selection process for these areas will be addressed in more detail in the second part of this article.)

Architecture selection is a fundamental consideration, but this is another example where there are typically legacy issues that must be dealt with in many cases. Selection of the best-fit architecture can be significantly influenced by the networks already in place, along with the strengths and weaknesses they bring to the situation. Overall system reliability objectives will also drive considerations and strategies for redundancy.

In many if not most cases, there are a number of factors influencing protocol selection. Experience, knowledge, and comfort level with installed protocols is important, but the availability to interface both existing and planned IEDs is also critical. This is another example of the need for an iterative process in design and how decisions in each area can impact choices for other design elements.

System Performance

System availability is vital and must be carefully addressed by using substation-hardened equipment in all aspects of system design. All critical equipment should meet IEEE Standard 1613, which may also include the substation computer. The definition of critical IEDs is very important as it will increase system cost whenever substation-hardened IEDs are selected to replace non-compliant devices.

System flexibility considerations include ease of expansion, provision of spare capacity, ease of replacement and ease of maintenance. System maintenance considerations can include items such as changing operational parameters as well as the configuration. With a modular system being supported by multiple vendors, changes to some IEDs will be easier than others, depending upon the evaluation criteria. Generally speaking, however, selected IEDs must support user interfaces that in turn, provide an easy and intuitive way to make system changes and adjustments. ■

Looking Ahead…

In Part 2 of this article, "Project Execution" (appearing in the March/April issue of EET&D) the author will present a case study explaining in more detail how the substation integration design process actually plays out, based on experience with an operating utility in the Northeastern U.S. – Ed.

About the Author

Craig Preuss *is the Engineering Manager for Utility Automation at Black & Veatch Corporation where he is involved in virtually all facets of substation integration and automation. Craig earned his bachelor's degree in electrical engineering from Valparaiso University in Valparaiso, IN and a master's degree in power systems from the Illinois Institute of Technology and is a registered professional engineer in the states of Illinois and Washington.*

During his 18-year career in the utility engineering and automation field he has authored several papers, presentations, and articles on topics dealing with substation integration and automation. Craig is an active member of the IEEE where he serves as the new working group chair for IEEE Standard C37.1. He was also involved in the writing of IEEE Standard 1615 and IEEE Standard 1686 as well as participating in other IEEE working groups. He is also a member of the ISA (Instrumentation, Systems, and Automation Society).

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2007 Growth Excellence of the Year Award - *Frost & Sullivan*

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