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Electric Energy T&D MAGAZINE

SEPTEMBER-OCTOBER 2006 Issue 6 • Volume 10

In this Issue

The Big Picture:
Rethinking The Enterprise

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CONSUMERPOWERLINE SAYS "DEMAND RESPONSE" PARTICIPATION HELPED SAVE THE CITY FROM A WIDER BLACKOUT

Energy Management Firm Calls on the Governor to Expand Strategic Implementation of Program to Avert Blackouts in the Future.

As New York City recovers from a triple-digit heat emergency and braces for the next, ConsumerPowerline, which helps companies manage their energy use more efficiently, says that a recently released Con-Ed report to the Mayor on the crisis provides confirmation showing that Emergency Demand Response programs helped save the city from an expansion of the blackout that crippled western Queens for more than a week, while also affecting Westchester County and other parts of the Tri-State area —and could hold the key to averting blackouts in the future.

The company, which is asking Governor Pataki to increase strategically placed emergency demand response participation – where, currently, large energy consumers agree to reduce their consumption in an emergency to help avert a power failure—says these programs led to a three percent reduction in critical energy use throughout the region, saving 411 megawatts, or enough to power more than 400,000 homes, and helping to stave off more widespread failures.

Citing a just released report from the Federal Energy Regulatory Commission (FERC) recommending that states implement Demand Response 'solutions', the firm wants state and local rules re-written so both large and smaller energy users, including single-family homes, restaurants and mid-sized apartment buildings, can be reliably called upon and economically targeted to the precise areas that are in danger of losing power during a heat emergency. The company says such changes could have spared Astoria its suffering in the dark, and would spare future Astorias from similar suffering.

Con-Ed recently submitted a report to the Mayor on the power outage, including the role of Demand Response, in helping to prevent a wider blackout to customers in Queens, New York.

"Our examination of the report and chronology of events, convinces us that a Demand Response program that included smaller energy users, and one that could be better targeted to the trouble spots, would have certainly helped to prevent the outages that left 25,000 Queens residents without power for more than a week, " said Mike Gordon, president and founder of ConsumerPowerline.

"While the Governor wisely encouraged all state agencies to intensify energy saving measures during the heat emergency, we not only need a louder call for demand response participation throughout the city and state, we need rules that will permit the 'the little guy'--small merchants and building owners, for example, to be a greater part of a targeted emergency demand response solution," he said.

Third Housing Co., Inc. of Electchester is a Demand Response participant that cut back on air conditioning usage when the call to conserve went out during the recent crisis. The complex and its neighbors saved enough electricity to power 2,000 homes, while suffering no loss of power itself, despite the up to 10-day blackouts in nearby Astoria and other parts of Queens.

"The residents of Electchester are really among the unsung heroes in helping to prevent a wider blackout--and not only because they cut back on sorely needed power," said Gordon. "Due to their critical location on the electricity grid, next to blacked out Astoria, it appears that their energy curtailment, in tandem with others' nearby, helped contain the blackout to a local area and may well have prevented a domino-like tripping of the system that could have resulted in a wider Queens problem,"

The way to make the biggest difference for New Yorkers is to strategically expand local Demand Response programs and to include smaller energy users so they can be targeted in an emergency to help stave off blackouts in specific areas on the brink of failure.

Gordon says that increasing strategic demand response participation from the current two percent to about 10 percent, would give the city much better tools to avert selective power failures, and full-scale blackouts.

Two federal agencies have recommended that demand response become an integral component of the nation's energy policy. They include a report by the Federal Energy Regulatory Commission (FERC) and a February 2006, US Department of Energy study.

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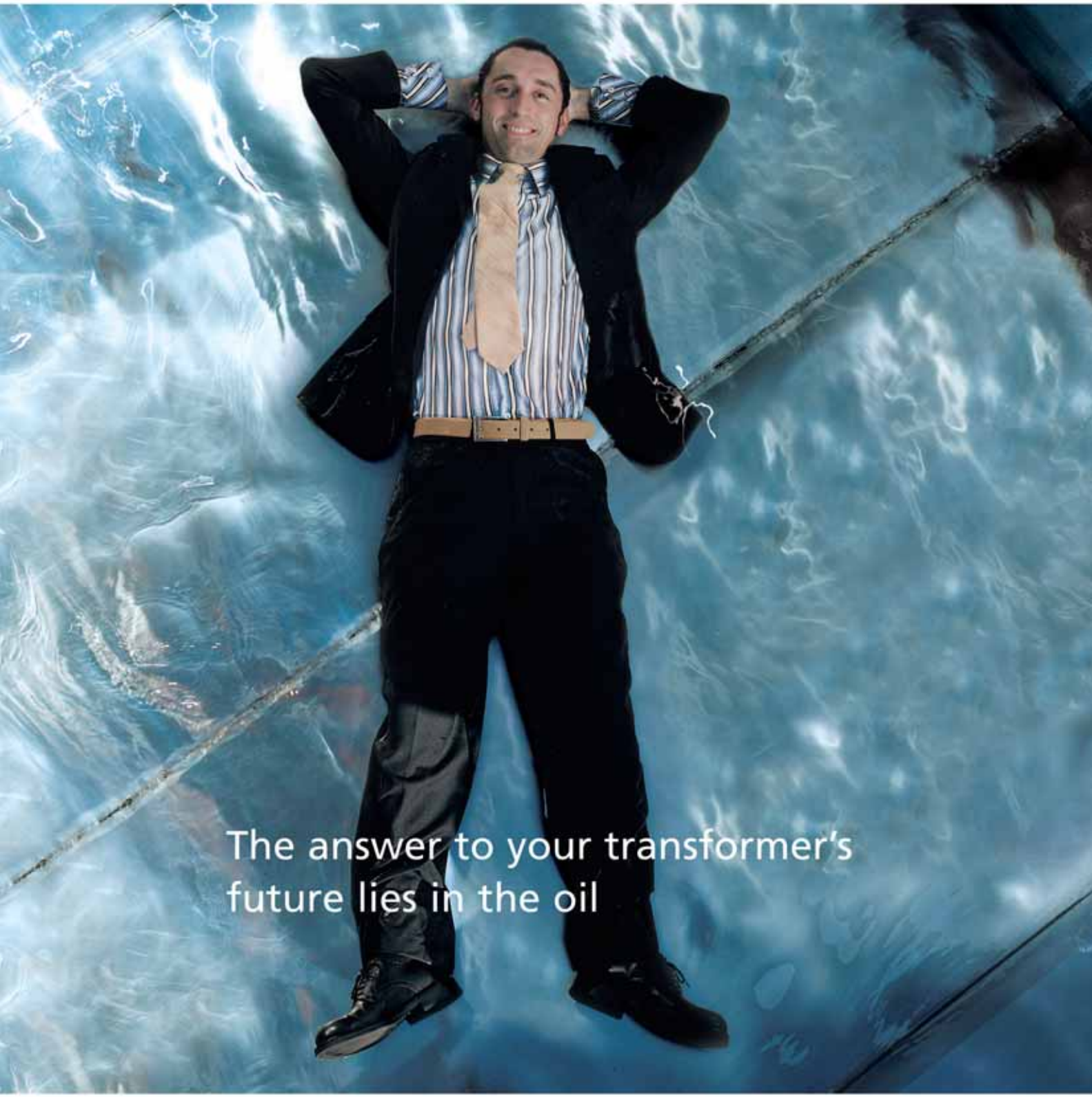
Nexus Energy Software launches upgrade to *Nexus MDM™ The Next Generation in Meter Data Management*

Smart meters are part of an advanced energy delivery system that relies on improved quantity and quality of information to guide both operational and customer decisions, including better load forecasting and control, and improved customer services including support for time-differentiated rates. Recognizing that advanced metering initiatives require a novel approach to manage the vast quantities of data they generate, Nexus Energy Software has launched a major upgrade to its proven data management platform.

Nexus MDM™ data management revolutionizes the meter data paradigm from the ground up to more easily process and store data for many million meters, along with associated customer, GIS, and weather data. It is now released and is being deployed at several key customers.

Nexus MDM stands apart from other meter data management systems in its ability to optimize what smart meter data can accomplish for utilities and their customers. By properly configuring interval meter data, stored with parallel customer, weather, billing, and GIS data, *Nexus MDM* achieves both operational and customer benefits. *Nexus MDM* incorporates Nexus' industry-leading ENERGYprism® applications that support customers online and in call centers with meter and bill analysis, shown to lower customer service costs while increasing customer satisfaction.



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Nexus MDM also incorporates Nexus' Energy Vision® applications that:

- Allow users to process interval and consumption data for load forecasting and settlement needs, including generating load profiles, applying loss factors, and calculating unaccounted-for-energy and aggregating loads according to any hierarchy.

- Incorporate GIS or other hierarchical information to aggregate customer loads along distribution circuits and identify the impact of customer loads on the distribution infrastructure and generate load values for modeling in load flow applications.

- Process interval and consumption data stored in the data warehouse to generate complex bills for retail or wholesale purposes.

Nexus MDM features an enhanced validation, estimation and editing (VEE) layer that ensures that high-quality data is stored in the system; as well as unique support for other business needs such as *revenue protection* by flagging and analyzing data with any number of quality indicators. The VEE layer uses well-tested profiling technologies to estimate missing data, as well as standard and custom validations and editing.

Nexus MDM also features a flexible data interface framework composed of a simple set of browser-based screens to allow users to configure all of the mechanisms that capture, interpret and load data into the warehouse.

Nexus MDM offers many advanced data analysis tools through an easy-to-use browser based interface.

For further information, please contact Richard Huntley, Vice President, Sales and Business Development. E-mail: rhuntley@nexusenergy.com
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MANITOBA HYDRO TO TEST NEW ITRON METERING TECHNOLOGY

Manitoba Hydro, in collaboration with Itron, is about to become the first utility in North America to deploy Itron's new generation of advanced metering technology. The wireless automated meter reading and communications technology promises to enhance customer service and system reliability, provide a platform for a broad range of potential new value added customer services - with a focus on energy conservation - and allow a true two-way communication between Hydro and its customers.

"We've tried different systems over the years," says Ted Cotton, Manitoba Hydro's Business Solutions Manager for Customer Projects, who is overseeing the new pilot project that was announced at a press conference on June 29. "This is the most promising. The communications protocol is much simpler."

Cotton notes that Hydro already uses a number of Itron-made products - including Itron electric meters and hand-held meter-reading devices.

"Itron knew we were researching the market for the most advanced current automated metering technology and approached us," Cotton says. "We decided to try the product."

Manitoba Hydro currently serves 510,000 electricity customers and 258,000 gas customers throughout southern Manitoba. Hydro's plan is to equip 5,000 residences in Winnipeg with the new meters in November as part of a year-long pilot project. These meters will be measuring electrical use. Cotton notes that meters to measure gas usage will be installed in 1,000 city residences in February.

"The gas meters aren't quite ready yet," he says.

The plan is to install 4,000 meters in a high density inner city neighborhood and the remainder in one of the city's newer suburbs. "In older neighborhoods, most meters are inside the houses," Cotton explains.

"We have problems with access with people not being home when our meter readers come by or people who are reluctant to allow strangers into their homes.

"In suburban areas, the issue is distance."

He says that at the conclusion of the pilot project next June, Hydro staff will analyze the meters' performance - especially in the cold of winter - and the information received. "We want to see how we can use the data creatively," he says. "With the new technology, we should be able to offer flexible rate plans, time of use rates, customer in-house energy use displays and load control and management and do remote electric service disconnects and reconnects."

As an example of the new technology's capability, Cotton cites a situation where a customer wants to know why his Hydro bill is suddenly

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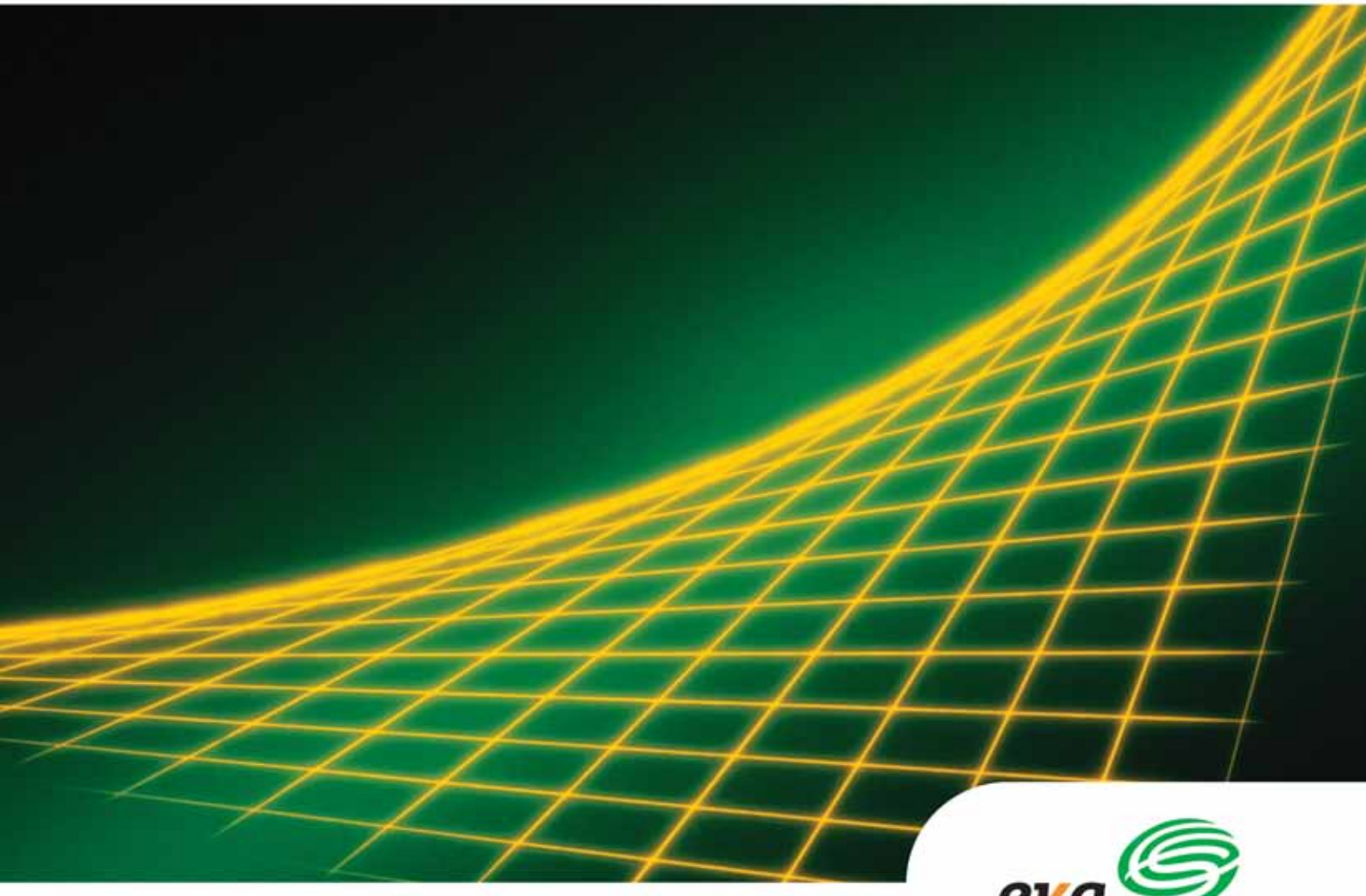

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higher. "We can tell the customer the moment that his energy use began to rise coincident with the installation of a new air conditioner in the house," he says. "In the long run, we should be able to help customers understand their energy costs and manage their energy use better."

Naturally, the readings will be accurate because Hydro staff won't have to estimate readings in houses the readers were not able to get inside.

"We will continue to send out our meter readers during the pilot phase," Cotton says. "And customers who are skeptical of new technology can still check the numbers on the meter with the bill."

He reports that several homeowners have already volunteered to participate in the pilot program.

"If we determine that the pilot program is successful, we will review the available technology before deciding which way to proceed," Cotton says.

"We have heard from other utilities who want to see how this turns out. We have already had requests to give updates at various industry conferences."

Cotton notes that the new technology should also help Hydro engineers in identifying potential transformer overheads earlier and take remedial action. "We will also be able to pinpoint the source of outages quicker," he says.

For more information, visit our web site at www.hydro.mb.ca.

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Recon X-Series adds new capabilities to Trimble's field-proven rugged handheld

Trimble's popular Recon® rugged handheld computer is now even more capable. The next-generation Recon X-Series features integrated Bluetooth and 802.11g wireless, more Flash memory, an improved color touchscreen and a built-in microphone. The Recon X-Series also comes with Windows Mobile® 5.0, the latest version of Microsoft's software for handheld devices.

The rugged Recon is ideal for utility applications where work is often completed outdoors in harsh environments. Like all Recons, the X-Series meets the MIL-STD-810F military standard for drops, vibration and temperature extremes. It also has an IP67 rating, so it's impervious to water and dust. That means utility workers count on the Recon when working in rain, snow, extreme heat and cold or other adverse weather conditions. Even if users accidentally drop the Recon onto pavement or into a puddle, it won't damage the unit, and they won't lose any data.

Despite its rugged construction, the Recon is compact and lightweight, making it easy to use and carry. It weighs just 17 ounces and has rounded edges that fit comfortably in the hand. A long-life battery allows the Recon to work for a full shift without a recharge.

Optional integrated wireless is the major enhancement to the Recon X-Series. Bluetooth wireless allows users to connect to peripherals like mobile printers without cables. 802.11g wireless provides access to local area networks, e-mail and the Internet.

The Recon X-Series is available in two models, both with more Flash memory than before. The Recon 200X features a 200 MHz Intel XScale processor and 128 MB of Flash memory; the Recon 400X features a 400 MHz processor and 256 MB of Flash memory. Both models also feature high-performance NAND Flash memory for improved data security.

Two CompactFlash (CF) slots allow users to add GPS, GPRS, digital cameras, bar-code scanners and other devices. Both Recon X-Series models also include 9-pin RS-232 and USB ports for a hard-wired connection to a laptop or desktop PC and peripherals.

The Recon has proven its performance and durability with thousands of users in real-world environments, including:

A U.S. Marines expeditionary force used the Recon to assess the damage to critical infrastructure on the Gulf Coast after Hurricane Katrina. Working in flooded and muddy conditions, the Marines provided disaster relief coordinators with detailed information on shelter, water/sanitation, medical, logistics and transportation requirements.

Black Hills FiberCom (BHFC) in Rapid City, SD uses the Recon as a real-time dispatch tool for its 40 install and repair technicians. As a result, field techs are more productive, dispatchers are more efficient, and with labor and overtime costs down, BHFC recouped its technology investment in less than six months.

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Powerline Caisson

In business since 1971, Erickson Air-Crane Incorporated owns and operates a fleet of 19 S-64 Aircrane helicopters worldwide. With a lift apacity up to 25,000 lb. (11,340 kg), this versatile machine is used in heli-logging. transmission powerline erection, heavy-lift precision placement, firefighting and hydroseeding. Erickson Air-Crane is the manufacturer and Type Certificate holder for the S-64 model Aircrane.

Erickson has erected over 8,000 miles (12,800 km) of transmission lines. The versatility of the S-64 Aircrane allows precision placement of most types of transmission towers ranging from Lattice Steel, Wood H-Frames, and Steel Poles. In the last decade, Erickson has pioneered the use specialized equipment in wetland areas to minimize or eliminate most environmental concerns. A specialized Heli-Template fixture, leased from American Pile Driving Equipment of Kent, Washtington, holds caisson foundations in plumb while a vibro-hammer vibrates the caisson to the required depth. A steel pole or H-Frame is set in place with minimal assistance from ground crews.

This procedure has been accepted by utilities as a cost effective, time efficient, and environmentally sound alternative to conventional ground-based methods. Jim Anderson, North American Construction Marketing and Sales Manager at Erickson Air-Crane has already seen many successful applications of this unique procedure along the eastern United States and Southern Gulf Coast areas. "What makes this system significantly valuable to the process is the accelerated project timeline and the decreased need for manpower, equipment, and costly intrusion into protected wetland areas." Says Jim, "The S-64 offers a strong and precise aerial delivery system specially suited to this type of work"

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Elster Electricity completes shipment of 220,000 Type AB electromechanical meters for residential AMR roll-out at Dominion

Elster Electricity, LLC announces that it has completed the shipment of 220,000 Type AB1R electromechanical meters with ERT modules to Dominion—one of the nation's largest producers of energy. This integrated solution allows Dominion to retrieve billing data from electric meters via radio frequency to a mobile AMR (automatic meter reading) data collection system.

Elster and Dominion spearheaded a comprehensive delivery and installation schedule that spanned from 2005 into 2006. Elster efficiently managed and met delivery deadlines for 38 large volume shipments to numerous locations, while responding to the emergency requirements of utilities in Hurricane Katrina–affected areas.

"We are proud of our long-standing alliance relationship with Dominion," stated Ronald B. Via, vice president of Elster Electricity. "Our Type AB electromechanical meter offers cost-efficiency and accuracy as well as long life and consistent service performance. We are delighted to have met Dominion's aggressive project schedule and short delivery window in order to keep the project on track."

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UCA International Users Group demonstrate the unique capabilities of the new international standard for substation automation, IEC 61850 at the CIGRÉ conference in Paris

Thirteen corporate members of the UCA International Users Group utilized a Ethernet network to demonstrate the unique capabilities of the new international standard for substation automation, IEC 61850, in the UCAIug exhibit at the CIGRÉ conference in Paris, France on August 28 through September 1, 2006. The exhibit demonstration encompassed several levels of multi-vendor interoperability all involving a wide variety of interoperable IEC 61850 products from several different suppliers. There was a demonstration of an IEC 61850 process bus where optical CT/PT signals were digitized as sampled values and transmitted over Ethernet to multiple relays for processing. There were several demonstrations of IEC 61850 clients in PCs, station computers, and bay controllers able to access real-time data in relays and other bay controllers using report by exception and other services for monitoring and control. The highlight of the exhibit was a demonstration of 11 different vendors exchanging protection oriented messages via the IEC 61850 Generic Object Oriented Substation Event (GOOSE) protocol with the results being displayed on a central HMI visible to the entire booth.

The exhibit provided demonstrations involving a wide variety of substation products including protection relays, bay controllers, Ethernet switches, circuit breaker controllers, substation computers, HMIs, communications drivers, protocol source code, network analyzers, substation design tools, consulting services, and conformance testing tools from ABB, Areva, GE Multilin, KEMA, OMICRON, RuggedCom, Schweitzer Engineering Labs, Siemens, SISCO, Team Arteche, Toshiba, UTInnovation and ZIV.

The purpose of the demonstration was to illustrate the many benefits that the advanced features of IEC 61850 bring to substation automation that goes well beyond traditional communications protocol approaches. IEC 61850 is a more comprehensive standard that includes protocols for process I/O, protection, and substation SCADA along with a standardized configuration language for devices, standardized device models and standardized object naming conventions that offers more interoperability with significantly lower installation, commissioning, and engineering costs. IEC 61850 is field proven with hundreds of operational substations in Europe and North America.

The event was organized by numerous volunteers from the UCA International Users Group. The UCAIug is a not-for-profit corporation consisting of 70 utility user and supplier companies that are dedicated to promoting the integration and interoperability of electric/gas/water utility systems through the use of international standards-based technology based on IEC 61850, the Common Information Model/Generic Interface Definition per IEC 61970/61968, and OpenAMI for advanced metering and demand response.

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By Michael A. Marullo, Contributing Editor

The Big Picture: Rethinking The Enterprise

When I was growing up in Upstate New York in the 1950s there was a program that came on our (black-and-white) TV on Sunday afternoons called, The Big Picture. It was all about World War II, and we watched it religiously every week. You see, my dad was a B-29 gunner in the Army Air Corps and flew 24 missions over the Himalaya Mountains ("The Hump" in WWII vernacular), but unlike some veterans that simply wanted to bury those memories along with their fallen comrades, he maintained an avid interest in trying to understand the parts of the war he had not personally experienced. So every week we watched, and I got an invaluable history lesson.

By the time I got to world history in high school I had a pretty good idea of what happened, when and where (and sometimes even why), throughout those war years, thanks to those Sunday afternoon tutorials. My understanding and perceptions were helped greatly by those programs since they were all narrated footage of the war itself; not some Hollywood production created exclusively for entertainment value. Sure, one could argue – probably correctly – that there was some propaganda angle to it, but for the most part, it was far more factual than anything I've seen on TV since.

In any case, it was quite educational for me. It gave me a sense of perspective that I don't believe I would have ever gotten just from reading about it. What it provided – besides the dramatic visuals – was just what the program promised: The Big Picture.

These days we constantly hear and read about The Enterprise: Enterprise solutions, enterprise applications, enterprise integration, and so on. But who is it that actually possesses this all important enterprise view; you know, the big picture? Well, I've actually pondered this quite a bit lately, and the answer is still unclear. Indeed, over the past five years, InfoNetrix research analysts have surveyed literally thousands of utilities across a wide range of types, sizes and locations throughout North America, and I cannot say that there are many of those surveyed who claim to be what one would call an enterprise expert.

On the contrary, what we hear more often than not is that there is almost always someone else – or several someone else's in the larger utilities – that you have to reach if you want to get a true idea of the big picture. And, because our surveys address a broad spectrum of utility automation and information technology products, systems and services, we are hard pressed to get a complete enterprise view from any one individual, or even from several. It turns out that people who have the big picture and can articulate it are in seriously short supply.

"Oh, you probably didn't go high enough in the organization," you might opine. On the contrary, although we are often speaking with VPs and other senior-level managers, we find that many of the lower level staff often have a better idea of what's going on in other departments than their department heads. Frankly, this doesn't surprise me. Just look at how projects are planned, designed and budgeted at most utilities; it's all based on each department doing its own thing. That is, the SCADA folks worry about SCADA; the AMR folks worry about AMR; and so forth.

So, back to the question at hand: Who actually has this Big Picture? While I'll admit that some utilities are beginning to take a more holistic view of their automation and information technology needs, their numbers are few; most continue to zero in on just one or two specific project areas each year. In many cases, how those projects will impact – or be impacted by – related initiatives is only given lip service or, absent from the process altogether. Let me offer some real-world examples of what I mean…

A few years back I was involved in an AMR (automatic meter reading) assessment for a municipal utility. Part of our analysis involved a broad view of how communications figured into their AMR plan. What we found was that the utility needed to provide a reliable communications backbone before any AMR project would be viable. When we ran the cost-benefit numbers, the cost of the requisite communications system put the project well below the utility's ROI benchmark, spelling doom for the AMR plan. However, by also looking at other automation needs across the enterprise (not part of our official mission; just a little common sense) we made an interesting discovery that dramatically changed the financial and operational dynamics of the project.

Apparently the utility had been trying for years to justify a load management project that was also not able to meet financial muster. Again, the problem was primarily the communications infrastructure needed to support the project. More specifically, the cost to provide the outbound connectivity to carry the load shedding signals simply could not be justified with the benefits accrued from the load management system alone.

When we looked over our investigative notes, it quickly became apparent that there was a potential correlation between the AMR and LM projects, the common denominator being the communications cost hurdle that was implicit in both projects. However, upon further scrutiny, we found that the AMR project was designed around providing a one-way inbound communications facility; the LM project around an outbound network. Each project carried 100% of the costs of planning, design, selection, deployment and support of the new comms network. Even though each project needed a one-way path, a substantial majority the costs were completely redundant, and providing a two-way link had only nominal incremental cost over a single, one-way link.

Upon arrival at this revelation, we all looked at each other in disbelief. How could it have not been evident to the utility that by combining the projects – one needing inbound and the other needing outbound connectivity – that both could be easily justified while also adding an invaluable, multi-use asset to strengthen the utility's overall infrastructure? The answer, we decided, would have to be carefully researched before presenting our recommendations since we didn't want to be suggesting what seemed to be an obvious approach, especially if it had already been evaluated and rejected earlier for reasons perhaps unknown to us.

We started our investigation by asking the various department heads about their individual budgeting plans; what we learned was fairly shocking. It seems that the load management project analyses had been done at least twice previously on a biannual basis prior to the AMR project ever being floated as a possibility. Because two full years separated the project initiatives each time they were brought to the budgeting table, no one involved had the visibility to identify the potential benefits of combining the projects.

Satisfied that the obvious had been overlooked (and after triple-checking all of the project justification numbers to make sure the ROI was calculated properly), we made the combined project the focal point of our recommendations. Lo and behold, the utility was amazed by our virtuosity, seemingly having elevated project justification to an art form! The fact is, all we really did was apply a little common sense by stepping back far enough to see the bigger picture and the greater good for all concerned. No rocket science was involved at all!

In another exercise a couple of years later, we were asked to develop a Technology Strategy Plan (TSP) for three utilities in the Northwest. In this case, the central theme of the project was to take a broader view of enterprise technology planning, implementation and integration rather than simply addressing a single set of narrowly focused automation/IT objectives. Even more important was the balance between internal and external factors. While at first this might seem obvious, standard utility project planning had never taken customer wants, needs or expectations specifically into the project planning process before.

This bilateral (i.e., internal-external) approach yielded many benefits, key among them the light it shined on what the utilities' key commercial, industrial and institutional customers expected from their provider. When we asked some of their most important C&I customers what they would like to see in terms of automation/IT measures that would have tangible benefits for them, many of them were quite surprised to even be asked since no one had ever done that before.

Indeed, by simply asking that question, new doors to improved customer relations and customer services that simply did not exist prior to the TSP initiative flew open for both the utilities and their customers. The C&I response was exceptionally positive as expressed by interest in new and creative initiatives such as SCADA and metering information sharing; web access to their hourly, daily and seasonal usage patterns; and more detailed billing information, to name just a few. Arguably the most profound impact of these exercises, however, is that they redefined the enterprise to be inclusive of not only other departments within the utility, but also the inclusion of customers in the automation/IT planning process.

The do more with less mantra foisted upon us all well over a decade ago has placed most utility enterprises on a collision course with formidable new challenges including aging infrastructure/workforce, security, customer satisfaction and service reliability issues. So, the next time you're planning or budgeting a new project, you might want to start by rethinking the dimensions of your enterprise. In the midst of an increasingly resource-constrained industry those lines might need to be drawn differently now, and the picture might need to be bigger – perhaps a lot bigger. - Mike ■

Behind the Byline

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

The Future of Our Grid: Is it Smart or is it Dumb?

By: Chris Hickman, Cellnet Technology, Inc.

Neil Armstrong named the electrification of the world as of the single biggest engineering accomplishment of the 20th Century at a national press club event in Washington D.C held on February 20, 2000. Armstrong's proclimation was based on a comprehensive survey conducted by the United States National Academy of Engineering. The irony that the first man on the moon called out the accomplishments of our industry ahead of computers, aviation, and even landing on the moon is obvious. What we do in the power industry isn't rocket science, it's even better!

Contrast this with the fact that the vast majority of power companies have no idea a consumer's lights are out unless they call to let them know. How can that be true? How can the electrification of the world and our electric grid be recognized as such a wondrous accomplishment and yet we have virtually no ability to 'see' into its distribution systems? Newton Evans Research estimates that distribution communication systems and SCADA are deployed to only 75% of North American substations and that distribution automation at the system feeder level is less than 20%. We can lose entire distribution feeders and not know about it until enough customers call in to complain allowing our outage management systems to predict the problem. Compound this with the fact that less than a third of customers actually bother to call in outages.

Less than 10% of the meters in North America are 'smart' - meaning that they can communicate their status and basic parameters back to our utility control systems in real time. Utilities are literally blind to any event that occurs below the feeder breaker level. For over 90% of the more than 2 million miles of wire that make up North American distribution systems, we have absolutely no idea that an event or an outage has occurred unless our customers call and tell us. As an industry, we talk about three 9's of reliability and cite the fact that, compared to any other product, the price of electricity has stayed dramatically low over the past few decades. These are not valid reasons for the status quo.

Let's talk turkey. Let's agree on some things that many of us will agree to privately but we are often afraid to carry into the boardroom (or to state in an article). The simple fact is that the power industry is incredibly risk averse, and we evaluate and re-evaluate opportunities well past the point when a decision should be made. This is a conundrum we lovingly refer to as 'paralysis by analysis.' However, this process has transitioned in the last 10-20 years from a 'knock' on the engineers that are protecting the system from new technologies or concepts to a 'knock' on the finance, legal and managerial staff that are responsible for next quarter's earnings instead of the long-term health of the connected grid.

Our industry is rampant with examples of insufficient investment leading to significant grid issues including brownouts, rolling blackouts and complete blackouts. Yet, with all of these front page examples that persist in recent years, utilities continue to cut budgets and staff in the face of declining grid performance and an aging workforce issue of epic proportions. At perhaps the single most critical point we are going to be dramatically short of experienced personnel to help us determine the best path forward. Nonetheless, we consistently see utilities laying people off as they merge and 'right size.'

I've laid out an argument to this point that we have limited technology deployed, we can't get sufficient money to invest in new infrastructure, and we're running short on experienced staff to run it anyway…so what's next? In the face of this backdrop, residential customer expectations keep rising, regulators demand more and more from us, and business customers are now demanding that the utility industry belatedly join the digital revolution. The reality is that the continued use of decade old or, in many cases, century old technology solutions and business processes to attempt to meet these needs is a path to failure and disappointment.

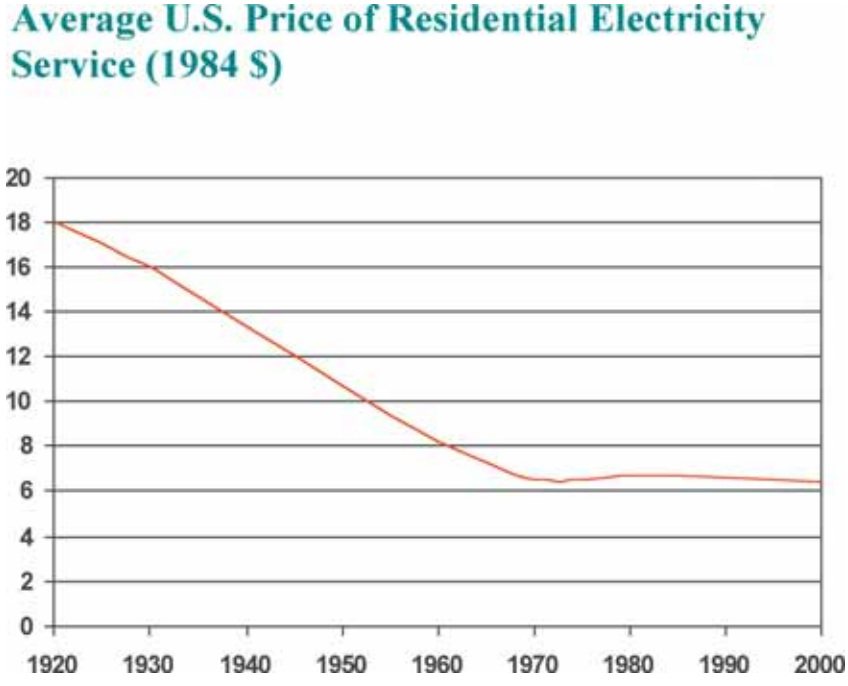
If this is true, where do we go from here? The answer is simple: we need an intelligent grid. Utilities that embrace this challenge in the next decade will be the market leaders 10 to 20 years from now. In the post PUHCA merger and

acquisition era, utilities with 'smart grid' programs will be the long term survivors -- the buyers. Unfortunately, it is quite possible that Wall Street and others will spend the first 5 years beating these forward thinking players and their stock down because they are actually out spending money on the future of their system rather than maximizing current profits. This is a situation that should be remedied as progressive utilities move forward with significant smart grid initiatives.

At this point you are likely asking yourself: why should we invest in smart infrastructure? Aren't we going to have the proverbial magic bullet solution, such as low cost distributed generation, that will obsolete this entire generation, transmission and distribution infrastructure? Assume for a moment that we will be predominantly dependent on central generation in a 30 year time frame. I doubt anyone would argue vehemently against this premise. In this circumstance, it's difficult for even the most ardent distributed generation advocates to argue for anything less than significant and dramatic improvements in the distribution -- and even transmission -- infrastructure to support these facilities. My opinion is that the 'last mile' of the distribution grid will be around for much longer than the next 30 years, and yet it is the single most ignored and neglected portion of our integrated system. We've spent over 100 years of 'good enough' and now it's time to take the dive into the grid of the future. We need to begin significant and necessary investments in distribution infrastructure.

The 'tipping point' for our industry's success or failure is rapidly approaching. Energy industry researcher Mark Mills recently commented, "We thus find ourselves facing what might be termed the 'perfect storm' — a confluence of three fronts: rising power demand, declining spending on power networks, and new threats from hostile forces. All this is occurring at a time when electricity is ever more critical to a modern economy and city." United States Federal policy makers have recognized this, and they have passed the Energy Policy Act of 2005. The spirit and intent of EPAct is to encourage and reward technology advancement and infrastructure investment for energy in the United States. Likewise, the Ontario Ministry of Energy has put forth its Energy Conservation and Responsibility Act, with key provisions supporting the deployment of advanced metering infrastructure (AMI). And, according to the Center for Smart Energy's Jesse Berst, "Grid automation represents a huge market opportunity, as utilities, regulators, and vendors struggle to overcome three decades of under-investment." The stage has been set and there is a convergence of industry opinion, but the next act of this play is even more crucial. How will state and provincial regulators, local policy makers, and utility executives respond?

A careful analysis of the following graphics should be central to this review:



As an industry we need to help regulators understand the need for infrastructure investment and the necessary price increases that will come as part of this investment. The political drive at the local level to keep electricity rates steady for customers could eventually help push the grid that serves them into failure. Utilities continue to blame regulators, market uncertainty and the infamous regulatory lag for their unwillingness to invest in new or upgraded infrastructure. Will customers just get used to rolling blackouts at peak summer loads and stop complaining about it? Will we accept mediocrity in our grid's ability to provide affordable, clean, efficient and reliable power?

There have been many studies performed and many articles written about our problems of today. Most of this work seeks to solve the symptoms rather than examine the root causes. A few utilities had the courage a decade ago to stand up and recognize the importance of their distribution franchises and were unwilling to divest, cut T&D capital investment and manage by the "book of the month club," or to next quarter's earnings.

IOU Construction Expenditures and Depreciation/Amortization Expense

Source: Edison Electric Institute and U.S. Department of Energy Data for US Market

Rather than being rewarded for actually focusing on their core business, they were punished in a variety of fashions. Each of those players looks brilliant today because they don't have a backlog of tens of millions of dollars of infrastructure projects that needed to be built yesterday, and they aren't having rolling blackouts. Is the answer to the core problem really that simple? Invest in our infrastructure. Yes, and unfortunately No.

As an industry we've struggled greatly with defining what a smart grid looks like and how it will operate. The result has been a slow evaluation and adoption of new technologies. As a result, the vendor community has been conditioned to be extremely measured in how far they push the envelope with technology and how much money they spend ahead of utility purchases. Vendors have been shown in years past that payback is often years down the road. But the academic phase of this smart grid effort has officially come to an end. The Electric Power Research Institute and Department of Energy have provided significant thought leadership and guidance through ESFF and Grid 2030. Utility industry executive leaders must, in turn, take the reigns and work with the vendor community to innovate and deploy the technology now that we need to meet the needs of the new digital economy for the next 30 to 50 years. The utilities that are willing to proactively pursue the smart grid, buck the 'run to failure' trend, and effectively partner with their regulators to do the right thing for energy infrastructure will be the big, long-term winners.

Many far sighted state and provincial regulators and utility leaders out there understand how critical energy infrastructure is to our entire economy and to our way of life. They are partnering together to 'fight the good fight' to invest and develop our North American grid into the grid of the future that it needs to be. I am holding out hope for a smart future. ■

About the Author

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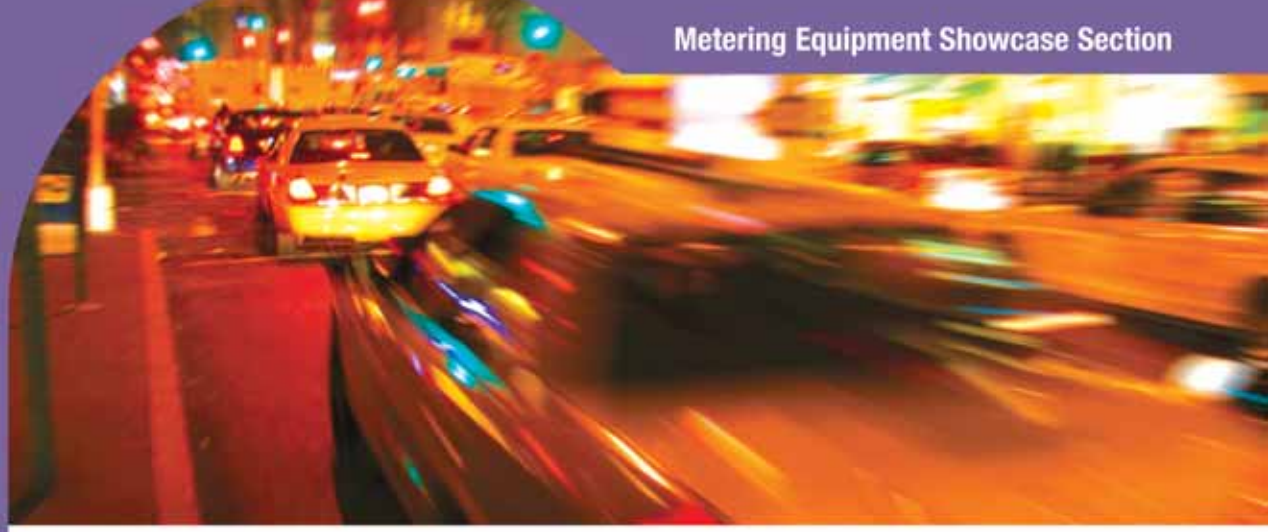
Chris Hickman has worked in the utility industry for 15 years. He has managed all aspects of transmission and distribution system engineering design, construction, maintenance & standards for both gas & electric utilities. In addition, he managed all R&D activities for PNM as well as Right-of-Way, Environmental, CAD/GIS, Safety, DOT and regulatory compliance and a variety of other groups.

Hickman served on the board of Avistar, PNM's unregulated subsidiary, and was a board member for IEEE's Power Engineering Society. He is currently the chair of the Electric Utility Management Program board at NMSU and is also a member of the Engineering Academy and the vice-chair of the Dean' s Advisory Council for NMSU. He received his BSEE and MSEE from NMSU, his MBA from UNM, and holds three patents for energy industry inventions and ran his own consulting firm before joining Cellnet in 2005. In his spare time during school, Chris was the captain of the 1992 NMSU Men's Basketball Sweet Sixteen Team.

http://www.cellnet.com



The EnergyAxis® System…Delivering actionable intelligence to improve your business

Released in 2003, Elster Electricity's EnergyAxis® System is being used by over 70 utility companies worldwide. The EnergyAxis System is an advanced metering infrastructure (AMI) system that utilizes patented smart metering technology. The system's two-way communication system is a controlled mesh network made up of smart meters that can communicate with other meters within the system using multi-hop, repeating, and self-registering technology.

A Vision for the Future

The vision behind the EnergyAxis System was to develop an economically viable multi-utility metering system for the residential and commercial and industrial metering markets that was easy to install and had minimal infrastructure requirements. By integrating products into the system, utilities have an array of cost-effective solutions they can tailor to meet their needs. Smart metering technology with two-way communications integrates the automated meter reading (AMR) function into the meter without using meter add on devices.

Success in Today's Market

Elster's EnergyAxis System is paving the way and helping to establish the trend of two-way communication to all meters. Utility companies worldwide are discovering how the system's smart metering technology helps them streamline their business operations and improve customer services. Large utility companies using the EnergyAxis System are now moving into full-scale deployments. The system's REX® meters with remote connect/ disconnect option enables them to improve final billing services, and reduce revenue losses due to lost or delinquent bills. The EnergyAxis System equips them to detect potential meter tampering and energy theft in a much more timely matter; enabling them to act quickly to reduce and recover revenue losses.

Smaller utility cooperatives and municipals are finding the EnergyAxis System is a cost-effective AMI solution that is easily deployed. Municipal utilities are beginning to find that the system meets their business case because it is capable of handling both electric and water metering. The system's voltage reads and load profile analysis capabilities enable utilities to diagnose and improve their local distribution system. The self-configuring, self-healing communication infrastructure is easily deployed by installing meters; no additional wiring or pole mounted equipment is needed.

Looking Forward and Planning for the Future

The Energy Policy Act (EPACT) was enacted in 2005. EPACT requires U.S. utilities to have a plan in place to offer any customers who request it, time-of-use (TOU) pricing, critical peak pricing (CPP), and real time pricing (RTP) within 18 months after its enactment. For those utilities already using the EnergyAxis System, much of their work to meet EPACT requirements is already done. The EnergyAxis System's smart metering technology allows utilities to execute TOU metering, interval metering, and dynamically change rate tiers as often as needed without visiting the meter for programming.

Has your company started planning how to meet EPACT's requirements? Now is the time to start, and the smart metering technology you should consider first is Elster Electricity's EnergyAxis System. The system can be strategically deployed to meet your specific needs. It is a cost-effective solution that is scalable in targeted small area deployments and large-scale roll-outs.

Talk to us today about how the EnergyAxis System can enable you to improve customer service and your bottom line. At Elster, we deliver technology to empower utilities.

Technology to Empower Utilities

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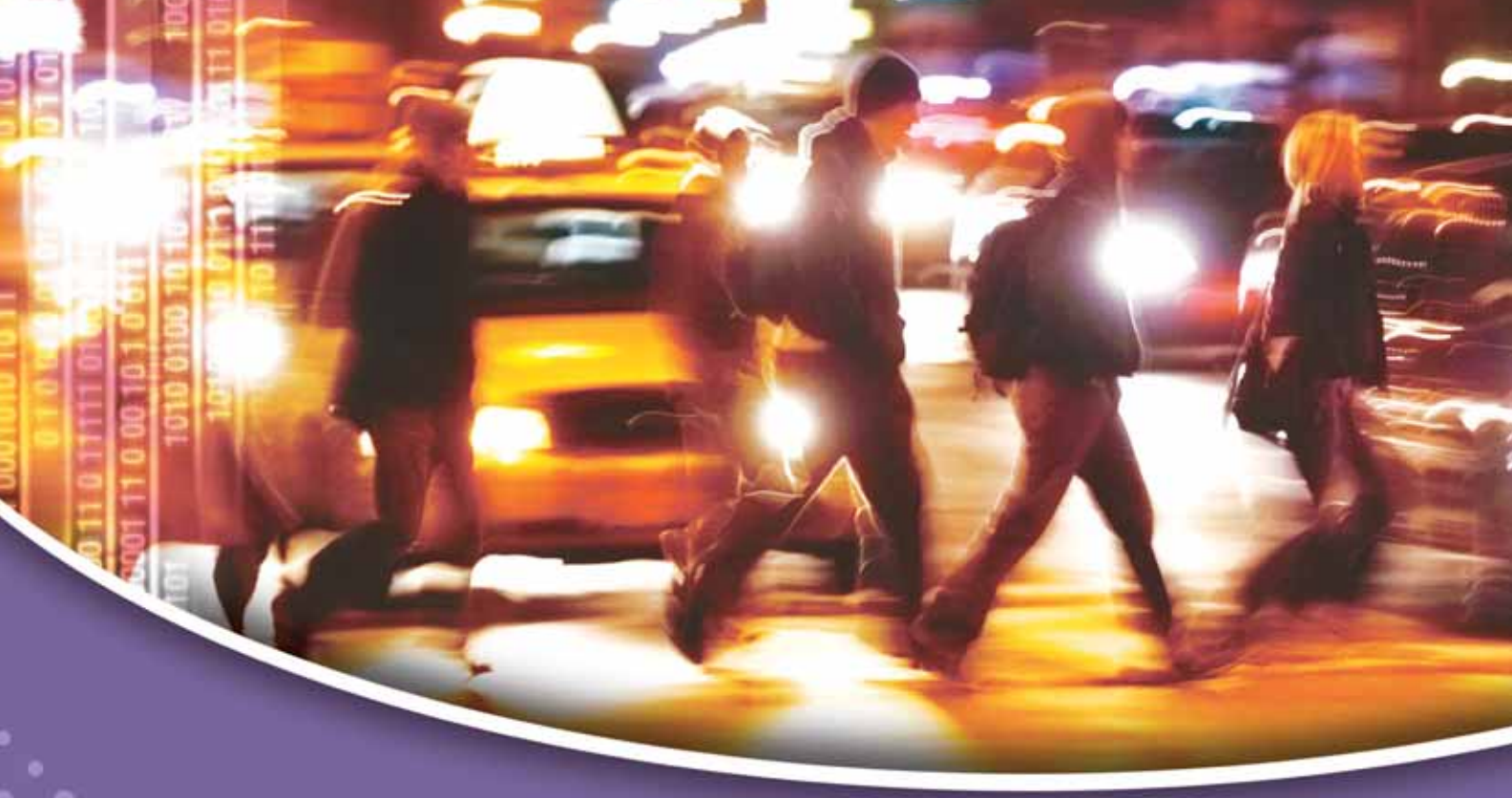

Elster Electricity... Empowering utilities with technology in step with the pace of tomorrow

At the forefront of systems innovation for more than 40 years, Elster Electricity is an industry leader and premier provider of Advanced Metering Infrastructure (AMI), communications, and metering automation systems for the utility industry. A worldwide resource for technology in step with the pace of tomorrow, Elster's practical solutions empower utilities to improve business operations, reduce costs, and enhance customer services.

An industry pioneer in the design and deployment of controlled mesh network technology, Elster's EnergyAxis® System is a comprehensive AMI solution for residential, commercial, and industrial electricity and water metering applications. The EnergyAxis System's intelligent two-way RF communications utilizes multi-hop, repeating, and self-registering technology to retrieve information directly from the meters.

Advanced in its capabilities, the EnergyAxis System delivers the high reliability, accuracy, flexibility, and robust operations utilities need to drive their business both today and tomorrow. Visit Elster at **www.elsterelectricity.com**.

Technology to Empower Utilities

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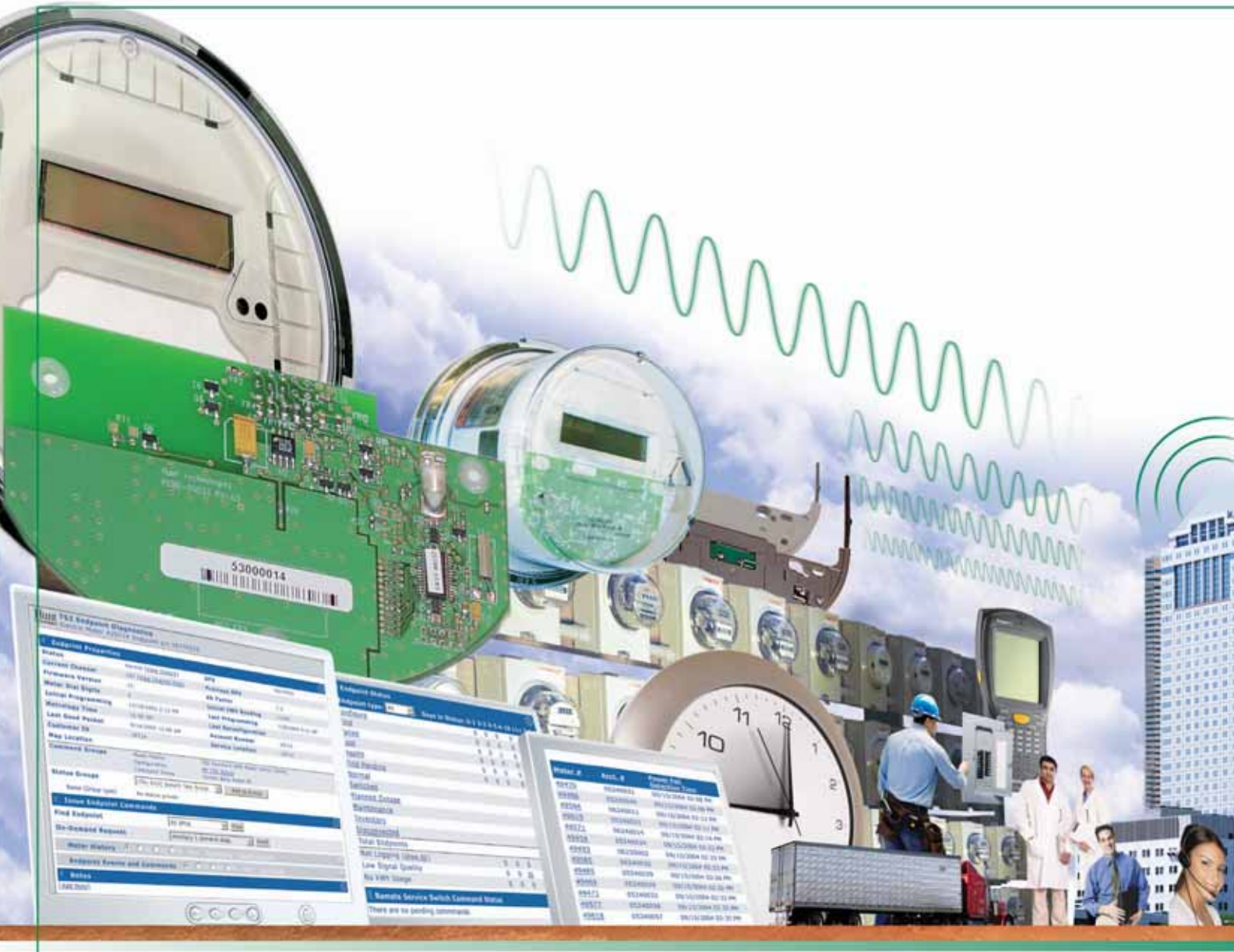

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The industry's only complete portfolio of powerful, cost-efficient and scaleable AMR and AMI technologies.

At Hunt Technologies, we understand that every utility has different AMI needs, and that, unlike others, a one-size solution does not fit all. For the past 20 years, we have dedicated ourselves to the development of the industry's only complete portfolio of powerful, cost-efficient and scaleable technologies that deliver the critical and timely information utilities consistently need to satisfy their many constituencies, no matter what the topography. With this unique breadth of experience and ability – and the industry's most powerful and interoperable software engine ever created – it's only natural that smart utilities, meter manufacturers and software developers rely on Hunt Technologies to offer them *endless possibilities.*

See us at Autovation, Booth 325

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TWACS® TECHNOLOGY

TWACS communication technology is truly unique, as it works by modulating the voltage waveform at the zero-crossing point, resulting in a communication system that uses the utility's network at the frequency for which it was designed and built. Data can be transmitted through any transformer or wiring configuration. TWACS technology requires no line conditioning or repeaters, and is not affected by capacitor banks, noise harmonics, feeder switching or underground to overhead transitions.

SYSTEM TECHNOLOGIES

DCSI provides utilities with a true two-way communication system and associated transponder products for advanced metering, Interval Data Retrieval, Dynamic Load Profiling, Time-of-Use data for Critical Peak Pricing, near-instantaneous Outage Verification, Load Control and Management, Power Delivery Quality Monitoring, Prepayment, Remote Hard Disconnect/Reconnect, and Tamper/Leak/Theft Detection. In addition, the TWACS Outage Assessment System (OASys™) is available as well as Short-Hop Radio Frequency (RF) as a solution for reading proximate gas, water and pit-set meters.

ADVANCED APPLICATIONS

TWACS OASys™ technology enables outage discovery, notification of appropriate personnel before the first customer call, system-wide outage assessment and accurate monitoring of restoration progress. TWACS technology enables delivery of vastly increased amounts of interval data at an extremely high rate of speed by fully exploiting parallelism inherent in the electrical grid. Utilities will find that compliance with provisions of the Energy Policy Act (EPACT) of 2005 relating to advanced metering devices can be more easily satisfied with deployment of the TWACS system. TWACS Prepaid Metering technology (PowerStat) enables utilities to offer customers the benefits of a more flexible billing approach, which will serve to provide those customers better means of managing and controlling energy expenses. Gas, water, propane and pit-set metering is enabled by utilizing the Badger Meter ORION® and TWACS technologies. Since TWACS provides two-way communication to, and into, each home and business, opportunities exist for communication-based consumer services, including energy efficiency, billing options, home automation and remote site monitoring.

LOAD CONTROL

TWACS load control and interval data delivery enables a utility to meet Demand Response provisions of the 2005 Energy Policy Act. TWACS multifunctional load control enables utilities to reduce highest-cost peak demand by creating the optimum diversity of deferrable loads without impacting energy sales, resulting in improved load factor. The system avoids creation of new peaks during system automatic load restoration - under system control or upon command. The TWACS load restoration system measures effectiveness by recording whether or not load is on at the time of shed cycle. It also minimizes the impact of inrush current that follows an extended outage by initiating cold load pickup.

COMPATIBILITY

The TWACS system is compatible with most residential and commercial meters including single-phase mechanical meters produced by all major manufacturers, several solid-state electric meters in their native protocols, nearly all water/gas dial encoders, and pulse generators/initiators. TWACS management software communicates with other utility computer systems and substations and is MultiSpeak3™ compliant for billing systems interfacing.

CUSTOMERS

DCSI's customers include ATCO Electric, Bangor Hydro-Electric, Florida Power & Light Co., Idaho Power, PG&E, PPL Electric Utilities, Puerto Rico Public Power Authority, TXU Electric Delivery, Wisconsin Public Service Co., and over 200 electric cooperatives and municipal utilities. PPL's project is the largest two-way advanced metering deployment in North America, and FPL's TWACS Load Management program is the world's largest two-way PLC Load Control project.

SYSTEM EFFICIENCY & INTEGRITY

The cost-effectiveness of the TWACS system is proven by its years of service to a wide range of utility customers. It's two-way communications capability has allowed utilities to leverage their systems with the introduction of new component and software applications without obsoleting existing equipment. The integrity of DCSI's system is an outgrowth of strategic research and development, superior design and production practices, and proactive technical service.

DCSI maintains a strong avenue of communication with TWACS clients via an interactive "customer care" program and an Annual User Group Conference.

Whether the reason to install an automated system is operations efficiency, healthier cash flow, improved customer satisfaction, or the ability to apply multiple value-added services – deploying a TWACS system is an investment in the "future proof" tool for the industry.

DCSI

Distribution Control Systems, Inc. (DCSI) is located in St. Louis, Missouri, and manufactures and markets their Two-Way Automatic Communication System (TWACS®) solutions utilizing power line communications (PLC) technology for utilities deploying automatic meter reading and advanced applications. Over 8 million two-way devices are installed or under contract.

To learn more about TWACS®, call 800-297-2728. Or visit us on the web at www.twacs.com.

A POWERFUL LINE OF THINKING

Brooks UPG focuses on experience, product selection to ensure smooth AMR deployment

Whether the AMR project is system-wide or only in targeted coverage areas – like for rural or hard-to-access customers – a team approach is important. Brooks Utility Products Group has worked closely with numerous AMR teams during the past decade to assist with the successful deployment of millions of automated points.

"Our experience in AMR deployment is the strongest advantage we offer customers," said Jeff Hanft, group vice president of Brooks UPG. "Our people have the experience to provide sound advice for the products utilities may need, when products should be shipped to ensure schedules are met, and other logistics questions and problems that may come up."

While Brooks UPG's district sales people are the first lines of customer contact, Hanft said it is typical for Brooks UPG's engineering, marketing, purchasing and other departments to get involved with customers' AMR projects.

One-stop product shop

While Brooks UPG doesn't supply AMR meters, it does supply nearly everything else – product-wise – utilities need for successful AMR deployment. It does this by pooling the resources of the three operations within the Utility Products Group: Brooks Ekstrom, Brooks Meter Devices and Brooks Security Products.

"From on-site and in-house testing equipment to a complete offering of meter adapters to safety and security equipment, Brooks UPG makes it simple and easy for utilities to get the equipment they need to successfully install AMR meters," Hanft added.

Meter Security

"Non-AMR meters are visually examined by a reader on a monthly basis. However, in AMR systems, without the meter reader's monthly vigilance, stronger, longer term meter seals and higher-security devices play a greater role," Hanft explained. "While AMR meters are designed to notify utilities if there is tampering, it's still not unusual for false positives to occur, and utilities can not be 100 percent assured that a tamper hasn't occurred."

In addition to keeping the meter secure, Hanft said that color-coded seals often are used during AMR deployment to correspond with the different project phases. Because so many people can be involved – contractors, T&D personnel, meter technicians, etc. – many utilities use color-coded meter seals to determine who previously worked at the meter.

In addition to the need for better meter security due to "fewer eyes in the field," better meter security assists with Sarbanes-Oxley Act compliance.

- Seals: A range of customizable seals, for ring and ringless style meters; all show tamper evidence and are extremely tamper-resistant. One popular AMR product is the High Security Padlock Seal. Made of high-impact acrylic and with a 1/8" (3mm) diameter steel plated hasp, the High Security Padlock Seal requires a cutting tool to remove it and is a durable option.
- Ring-style locking devices: Five options are available, depending on desired level of security, and how utilities want meter access. The new stainless steel click ring with a built-in barrel lock does not require a key for deployment thus adding to the internal security of the device when deployed by contractors
- Ringless-style locking devices: Six options are available to fit nearly every ringless meter.
- Barrel locks: Four options are available for F, G, I and S Series.

Meter Adapters

Meter technology is improving, with not only AMR capabilities, but with smart metering and the use of meters for non-traditional applications. Therefore, to get the most out of existing installed equipment, utilities should seek a supplier with options for meter socket adapters and interbases.

For AMR deployment, Brooks UPG products include:

- Single and Polyphase A-base Adapters and B-base Adapters: Various styles allow simple, cost-effective means for replacing obsolete meter form types with socket-type meters.
- EK Series™ Extender Adapter: The EK Series™ meter-socket extender adapter accommodates various interface devices such as for service disconnect, PC boards, surge suppression equipment, communication interfaces and recording devices.
- Lo-Profile™ Extender Adapters: The Lo-Profile™ extender adapter is 1.2 inches deep – the industry's lowest profile adapter. Its low operating temperature makes it one of the coolest operating production-line extender adapters. A one-piece shell maximizes interior space, and eliminates the need for gaskets.
- K-Base Conversion products: A range of adapters, kits and products to convert K-Type installations to socket-style enclosures, and accommodate AMR and other technologies. The K-Base products include Low Profile-K4 and K7 Conversion Adapters, K4 and K7 to Current Transformer Conversion Kits, K4 and K7 Safety Shields, K7 Safety Jumpers (patent pending), and K-Base Socket Cover Gaskets

Safety Equipment

While AMR meter deployment should be done as quickly as possible at each residence to minimize customers' inconvenience, employee and contractor safety should never be sacrificed. "Testing for proper loading, short circuits and backfeed can minimize the risk for injury, and ensure deployment can continue as scheduled," Hanft said.

- S-120 Single Phase Meter Socket Tester: Safe and simple to use, it checks meter sockets for short circuits, grounds, backfeed and wiring errors.
- Load Indicating Socket Tester: In addition to safely checking for phase-to-phase and phase-to-ground faults, it determines the connected load inside the home prior to setting the meter.
- Voltage Indicating Socket Tester: Designed to perform various safety checks prior to setting meters, it detects phase-to-phase and phase-to-ground faults, detects potentially dangerous backfeed conditions, and indicates phase-to-phase and phase-to-ground voltage.
- Voltage/Load Indicating Socket Tester: Versatile, the V/LIST protects both the installer and the end customer's equipment. Used prior to setting the meter, it safely checks for wiring errors that could lead to dangerous phase-to-phase faults or backfeed conditions. The V/LIST also checks for connected load, and indicates phase-to-phase and phase-to-ground voltages.

Brooks UPG also offers a series of warm-up boards that ensure smooth, in-house meter testing to make field-installation quicker.

For additional information about Brooks Utility Products Group, visit www.brooksutility.com.

INTRODUCING

The SNAP2™

2-Piece Pre-Wired Meter Socket

IT'S TWO! TWO! TWO! GREAT ANSWERS IN ONE!

It's a money-saver!

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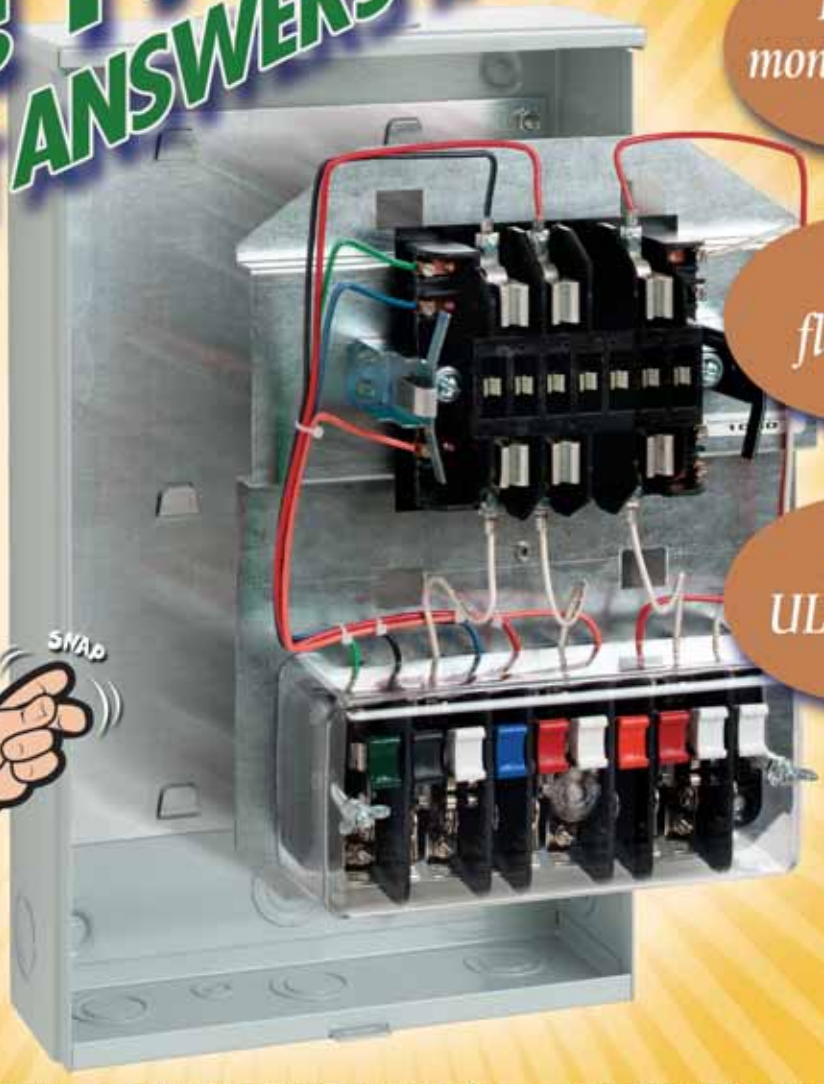

It's the amazing new Brooks Meter Devices' **Snap2** pre-wired meter socket. And, it's UL-listed.

It's a money saving device because you avoid the cost of stocking the empty meter socket and cover. You also avoid costly field mistakes and coordination problems.

It's a flexible device. Your installer just snaps a pre-wired panel built to your specification into the empty meter socket previously installed. This patent pending snap together design reduces a field installation from what used to take hours to just a matter of minutes.

And the **Snap2** pre-wired meter socket is just one of the innovative new answers that Brooks Utility Products Group brings to the industry.

So if you're looking for a better way to install transformer-rated meter services, you need to know about the new way to do it.

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We Have Answers.™

Integrating Data from Many Sources Provides New Opportunities in Energy Theft Detection

By: Michael Madrazo founder and President of Detectent.

Energy theft detection has been discussed at all utilities, deployed at many and is a passion to a few. Theft detection in general terms implies that proactive measures have been taken to identify theft of electricity, gas or water. In almost all cases, the measures taken have been the implementation of a "tip" program that rewards meter readers for notifying the revenue protection department when suspicious conditions are noticed in the field. Once implemented, these programs become reactive rather than proactive, with the revenue protection investigators waiting for tips to investigate. With the advent of Automatic Meter Reading (AMR), meter readers are becoming obsolete as are tip based programs.

Recently, a new approach to the discovery of energy theft has emerged in response to these changes. The approach combines data from many sources, including AMR tamper flags, and uses that data to not only identify cases of theft at a specific customer site, but to do so with a scheme that prioritizes investigation efforts by targeting higher probability and higher value cases.

Focus on high value cases

Using a proactive approach to energy theft detection removes the handcuffs that have been placed on utilities that relied on tip programs to generate revenue protection leads. Even though many studies have shown that 80% of the dollars lost to theft by utilities is in the commercial sector, 80% of the investigation effort has been put into the residential sector. Residential leads typically result in cases worth hundreds of dollars; focused commercial leads tend to be in the thousands, and sometimes hundreds of thousands of dollars.

AMR tamper flags do not provide enough information

Automatic Meter Reading systems have worked well for identifying usage on inactive meters but their usefulness in the war on energy theft nearly stops there. There are just too many legitimate causes that generate false tamper flags and in addition, there is no means to prioritize the flags once generated. As a result, most utilities ignore the tamper reports generated by their systems. Additionally, the higher dollar commercial cases have more elaborate transformer rated equipment and as a result tampering often occurs away from the meter.

This does not mean that AMR tamper flags are useless though. Through integration with other data, the valuable information provided by an AMR system can be used effectively. Tamper flags have been ignored because there has been no automated way to evaluate whether they are valid or not. If a tamper flag is truly indicating that meter tampering has occurred, then the tampering will show up in other information about the customer in a way that validates the flag. In order to effectively validate AMR tamper flags it is first necessary to have methods that will identify the abnormal patterns caused by each.

It all starts with knowing the customer

In the residential sector a meter and a customer are usually one in the same, but many commercial accounts are made up of multiple meters which are often billed to different accounts. These separate meters and separate accounts must be merged to truly represent the energy usage of a customer and to compare their patterns against their peers.

Figure 1 shows a simplified example of how even a proactive approach can get fooled by analyzing the individual meters at a customer's site. The business in Figure 1 is a single premise but with meters A & B that were installed at different times and as different accounts.

Figure 1a: Cooler on Meter A

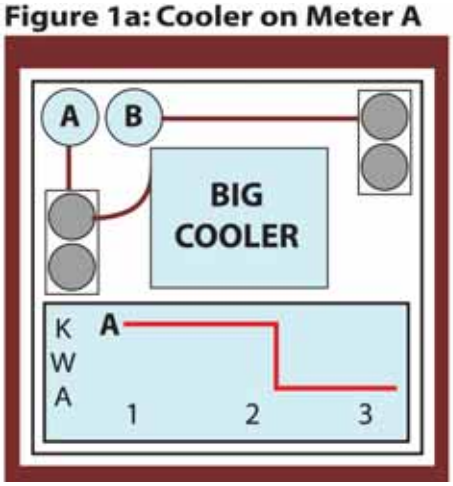
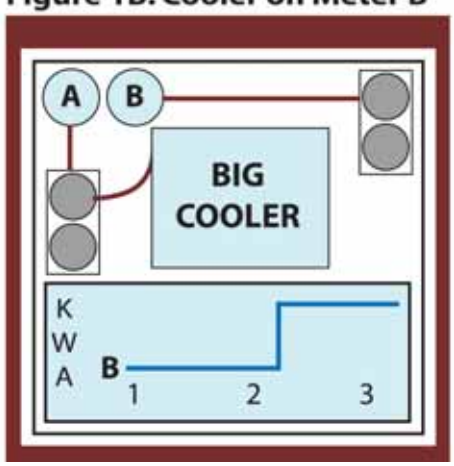
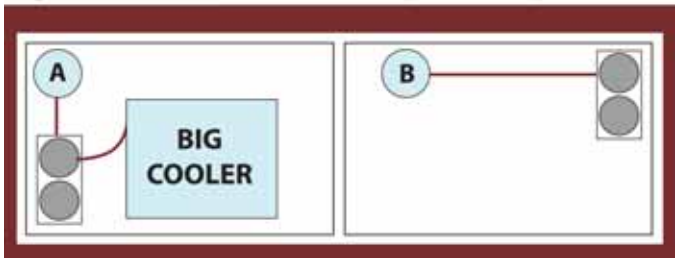


Figure 1B: Cooler on Meter B



Each meter has one outlet attached to it and there is a large cooler at the business. An event is caused if the cooler was plugged into meter A's outlet (Figure 1a) and then the plug is moved to meter B (Figure 1b). The three month electric usage for meter A would drop abruptly, and show up as a potential theft case using meter based analysis. The three month electric usage for meter B would have the opposite profile. This event would not have been flagged if the customer was analyzed after first combining the consumption of all the related meters. Figure 2 depicts a common situation where a business in a strip mall expands into the space next door, thus occupying two premises. The same false event would be introduced in this case without account merging, but the solution is more difficult since the two accounts are at different addresses.

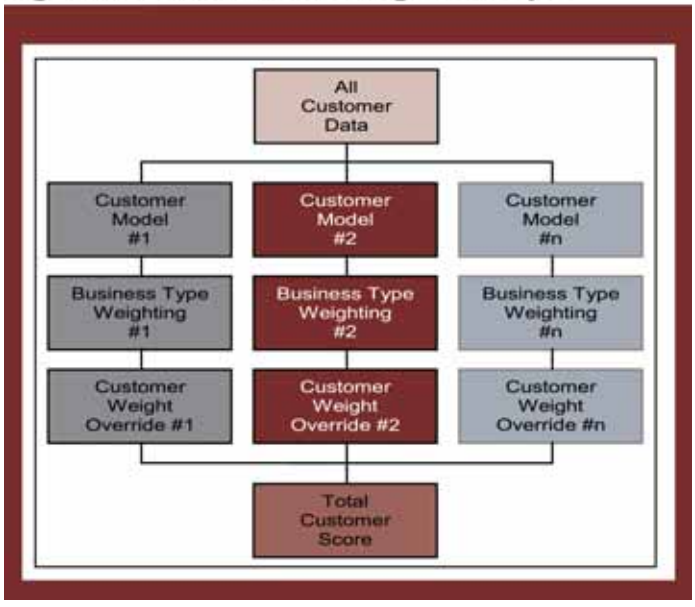
Figure 2: Business made up of two premises



Fortunately, sophisticated matching algorithms are now available that can mine the information in all accounts in a Customer Information System (CIS) to pair the accounts that really represent a single customer or business. The combined accounts can then be compared as a business to peers using different methods to determine how its patterns compare to the group.

This leads to another major issue faced when performing peer group analysis, incorrect business type information. Business codes (SIC, NAISC, etc) are obtained by a customer service representative at the time a commercial account is established. For many reasons incorrect codes are entered initially and are rarely kept current over time. Experience has shown that only 10-25% of the business codes are correct for most utilities. The solution to the business code problem uses the same sophisticated matching algorithms used to pair meter based accounts into customer groups. It has been found that Yellow Page and other business databases contain much more accurate business classification information as well as a wealth of other data about each business. We can truly know the customers we are analyzing when these databases are purchased and their listings are matched to the utility accounts.

Figure 3: Detection Scoring Technique



The process of detecting theft can begin once meters are merged to represent the entire business, or "customer", and data from all available sources is compiled for that customer. Useful data for analysis includes:

- Electric/gas/water consumption
- Electric/gas demand
- Weather data
- Correct business codes & sub codes
- Real estate records
- Employee information
- Financial information, including credit rating

Using all the data about the customer

Let's introduce the concept of a "Customer Model". A Customer Model as the name implies looks at a feature or pattern of use by a customer. There are many reasons why energy is un-metered, therefore there must be many ways to detect these conditions. These detection methods are referred to as Customer Models because they compare the energy use of a business with the model profiles of their peers. Examples of Customer Models that have been deployed are:

- Slope Deviation
- Load Ratio Deviation
- Energy Ratio Deviation
- Heating Gas Deviation
- Meter Capacity Deviation
- Building Capacity Deviation
- Excessive Seasonal Variation
- Bent Disk Profile
- Credit Risk Profile
- Blown Fuse Profile
- Erratic Profile

It is not efficient for revenue protection departments to simply generate lists of potential theft cases; they need a way to prioritize their work. For example, just searching out accounts with a specific drop in consumption will result of thousands of cases. In most of these cases, the drop will have occurred for legitimate reasons. Prioritization has to be done so that the investigation staff can focus on the highest probability cases. A total score can be derived, as shown in Figure 3, by calculating component scores with each Customer Model, applying a business weighting to each component score then applying an optional customer level weighting to complete each component score.

These final component scores can then be combined to produce a single total score that represents the likelihood that energy theft is occurring.

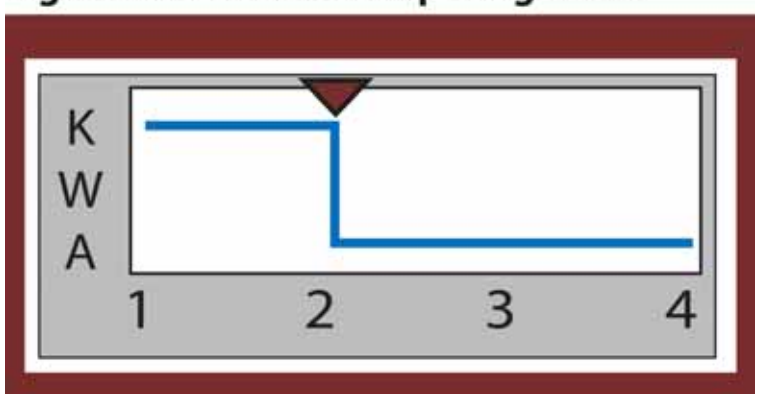
Using many data sources and a combination of models that look for independent features in a customer's consumption profile has transformed theft detection into a viable and cost effective solution for utilities. All previous attempts to analytically identify energy theft resulted in success rates of 3-5%. These new techniques have delivered an average success rate of over 20% for those who have deployed them.

Benefits of looking beyond AMR

The Customer Model approach to theft detection has been proven to be a new and effective method of identifying energy theft. The addition of AMR tamper flags provides an additional and independent indication that an event has occurred at a meter. The two most common AMR tamper flags are Meter Removal/Loss of Power and Meter Tilt. If the event the AMR flag signals is theft related, then one or more of the Customer Models validates it.

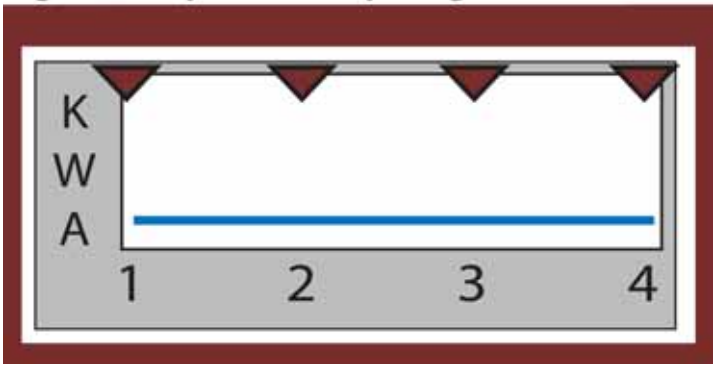
The best way to emphasize how Customer Models work together with AMR flags is through analysis of some examples. The first example is a meter that is removed to wrap copper wire around the meter prongs, thus creating a path for the current around the meter. When reinserted in the socket, the meter will only register one half of what is actually being used. This type of event would most likely cause both a Meter Removal and a Tilt flag in the AMR system for a single month. These tamper flags are denoted by the red triangle in Figure 4.

Figure 4: One Time Tampering Event



The account associated with the tampers flags will be marked as suspect in the detection system rather than dispatching investigators to a site. The energy usage from all meters that make up the account will then be monitored to validate that a consistent drop in consumption follows the tampering event. All other available information (i.e. corresponding drop in gas or water, change of name on account, etc) will be used as well to differentiate between a theft event and a change in business operation. If the ongoing usage on the account supports the theory of a theft then the utility would dispatch resources to investigate. In the interim, all false cases would have proven themselves to be legitimate thus excluding themselves from further scrutiny.

Figure 5: Repeated Tampering Events



The previous example assumed that a new event occurred after the accounts were being monitored. In a perfect world this approach would catch most cases. However, energy theft has probably been occurring since Thomas Edison's days. The good news is that techniques have been developed to identify situations with no recent "event" as well. The second example is when a customer has removed their meter and inserted shunts into the socket for 15 days each month, and this has been occurring for years. As with the first example, one half of the consumption is actually metered each month. Tamper flags would appear every month as shown in Figure 5 but there would not be a corresponding drop in consumption to support the tampering event.

In this situation the detection system would mark the account as a potential intermittent situation and immediately use all available information to verify or ignore the repeated tamper flags. Customer information such as electric demand, gas and water consumption, meter capacity, monthly consistency and neighboring account tamper flags are all used by several Customer Models to determine if these AMR tamper flags are valid. In this scenario, a total score would have been computed from the combination of several component scores without the tamper flags. Integration with the Customer Model theft detection system allows the AMR tamper flags to become a key component of the prioritization scheme and help move this case to the top of the list.

A new opportunity for utilities

Whether delivering electricity, gas or water and whether using meter readers or AMR to collect consumption readings, there is a new opportunity to accurately and efficiently identify theft of these valuable commodities. New techniques and the availability of electronic information have enabled the creation and application of an energy theft detection solution that not only identifies cases but uses all available information about the customer to establish a total score. The score in turn enables a utility to focus their valuable revenue protection resources on the highest probability cases.

Moreover, the implementation of a Customer Model based detection system allows AMR tamper flags that were once discarded to become a valuable part of the overall revenue protection scheme. ■

About the Author

Michael Madrazo is the founder and President of Detectent, the pioneer in developing analytical revenue protection solutions. Detectent has helped utilities across the country increase the efficiency of their revenue protection efforts by implementing proactive theft detection tools and services.
For more information about Detectent, visit www.detectent.com or call 760-233-4030.

Roadmap to the Future: Integrating Substation Information and Enterprise Level Applications

By: John McDonald, KEMA

By: Ali Ipakchi, KEMA

The past decade has seen a rapid advancement of technology supporting transmission and distribution utility engineering and operations. As such, the utility industry has increasingly turned to information and automation technology as a means to increase the efficiency of operations and to improve customer service.

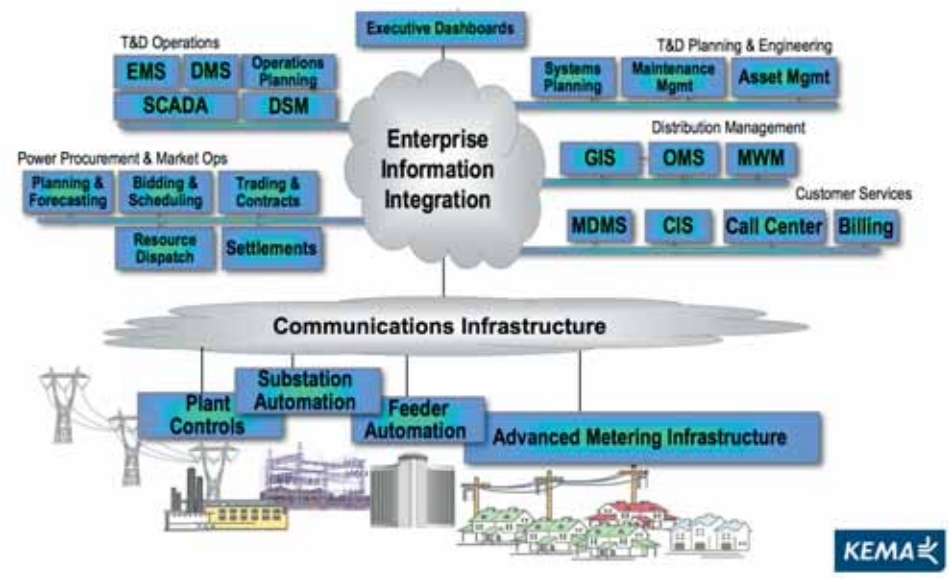
Traditionally, technology and automation projects are scoped, designed and deployed to support a given organizational unit. Often business function owners, faced with a specific business need, lead the procurement of a new application without enterprise level considerations for information integration and management, systems maintenance, and long-term support. The utility industry also faces the complexity of the real-time grid operations, system reliability, specialized mission critical applications and ever-changing regulatory environment and requirements. This is combined with more traditional IT paradigms of customer information, customer services, billing and back-office functions, asset management as well as administrative functions.

However, the industry has recognized that improved grid reliability, enhanced customer services, and improved operational efficiency will require information integration across the enterprise and enhanced levels of automation. User communities expect timely and often ubiquitous access to certain information, while management maintains pressure on costs, and higher levels of service quality and reliability. The emerging Utility of Future concepts for Smart Grid demand timely availability of additional information and integration of data and functions across traditional utility organizational boundaries. The improved access to information must be balanced with the appropriate levels of cyber security across the enterprise. And information management and control policies need to be in place to support access, reporting and audit requirements.

These challenges require utilities to establish tenets, policies and procedures for governing information assets and systems. To be effective, however, these tenets need to be driven by both requirements of IT systems management, as well as the realities of utility and grid operations and their specific business and technical requirements.

The technology

Traditionally, substation data were acquired through Remote Terminal Units (RTUs) and processed by Supervisory Control and Data Acquisition (SCADA) applications in support of power system operations. The introduction of multi-function digital relays and other Intelligent Electronic Devices (IEDs) at substations has made additional data available that can help minimize system restoration time, reduce equipment maintenance costs, and improve equipment availability and system reliability.



Modern substation protection and control systems use local-area networking technology to interconnect computer-based intelligent electronic devices that are able to communicate high-rate streams of electrical or other measurements (operational data) as well as records of how the devices and the power apparatus reacted to faults, system disturbances, and normal cycles of operation (non-operational data). This data is required to analyze the transient and long-term performance of the power system and its control systems. As compared to older non-intelligent systems that did not alert the utility of business opportunities or impending problems and disasters, the new systems provide vast quantities of valuable data.

Telemetry data, equipment conditions, digital fault recorder (DFR) and sequence of events (SOE) data can now be made available to users and applications in a consistent, and reliable fashion, using data marts and enterprise level integration schemes. This can facilitate the adaptation of performance enhancing strategies such as condition-based inspection and condition based maintenance (CBI/CBM) to improve equipment and system availability while reducing O&M costs. Continuous monitoring of dissolved gas levels, oil temperature, vibration levels, and HV transformer loading, for example, allows for the dynamic adjustment of equipment ratings to improve asset utilization and scheduling of inspection or maintenance. Timely access to, and analysis of, Digital Fault Recorder (DFR) and Sequence of Events (SOE) data allows quicker determination of fault location, and quicker service restoration.

Some utilities that integrated or automated substations hoping to get information for better management have found themselves wrestling with masses of data that overwhelm and handicap the organization. Realizing the strategic benefits of substation data is hindered by utility IT systems that frequently are not designed to allow access to this data by engineering and O&M applications. Comprehensive enterprise level substation systems integration (ELSSI) initiatives can help electric utilities get their arms around the huge bodies of data now stranded in substations. Converting masses of operational and non-operational data into business intelligence, organizing this intelligence, and interfacing it with enterprise-level applications can yield operating and financial benefits.

The key is to enable timely access to substation and equipment data by enterprise-wide users in planning, engineering, operations and maintenance that need this information. Utilities need to develop communications and processing systems that yield hard, timely, and succinct information for system operating security, economic operation, asset management, maintenance management, system planning, capital planning, and resource allocation. ELSSI adopters should understand key business metrics that support closed-loop business improvement processes. This makes it far easier to justify existing or new investments in substation automation and communications systems, and to reach the true payback promised by these substation systems.

Users also need to develop an approach that captures, organizes, and applies the data to assess improvements to system security and reliability, predict or schedule repair, replacement, or upgrading and the spending required, and to determine the most economical way to operate the system and the business. The challenge is to bridge the gap between the available substation data and the business goals. Utilities can bridge the gap by taking a number of interconnected steps including:

- Road-mapping solutions based on long-term utility business objectives;
- Planning communications system, data hosting, gathering, protection, and cyber security design;
- Organizing and interfacing data to applications that extract information;
- Selecting and developing applications that clearly and succinctly present all the enterprise users with the levels and types of information they need to perform their jobs; and
- Designing enterprise processes that close the loop between the management information delivered by ELSSI and the business improvements that result, constantly detecting and correcting problems, and constantly improving the whole cycle of information processing and use.

Roadmap for the future

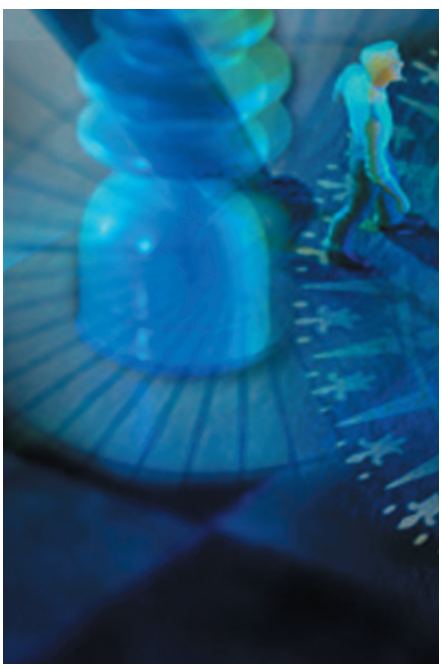
Enterprise level systems integration is a complex process involving technology, applications, data, business process and people. Focusing on the road-mapping solutions step provides a high-level overview of general issues and approach for establishing a strategic plan for IT technology and systems integration across a utility enterprise.

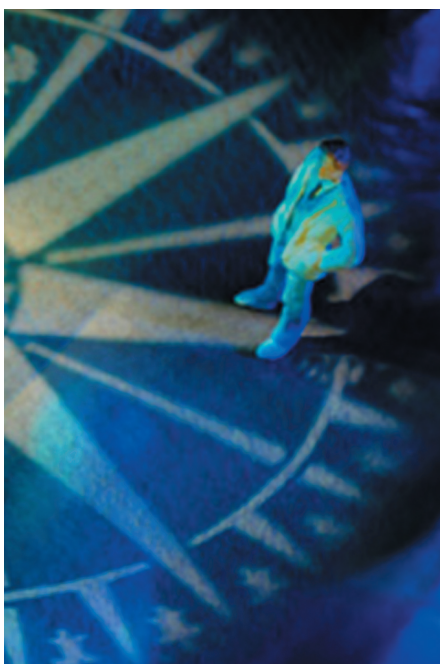
A holistic view

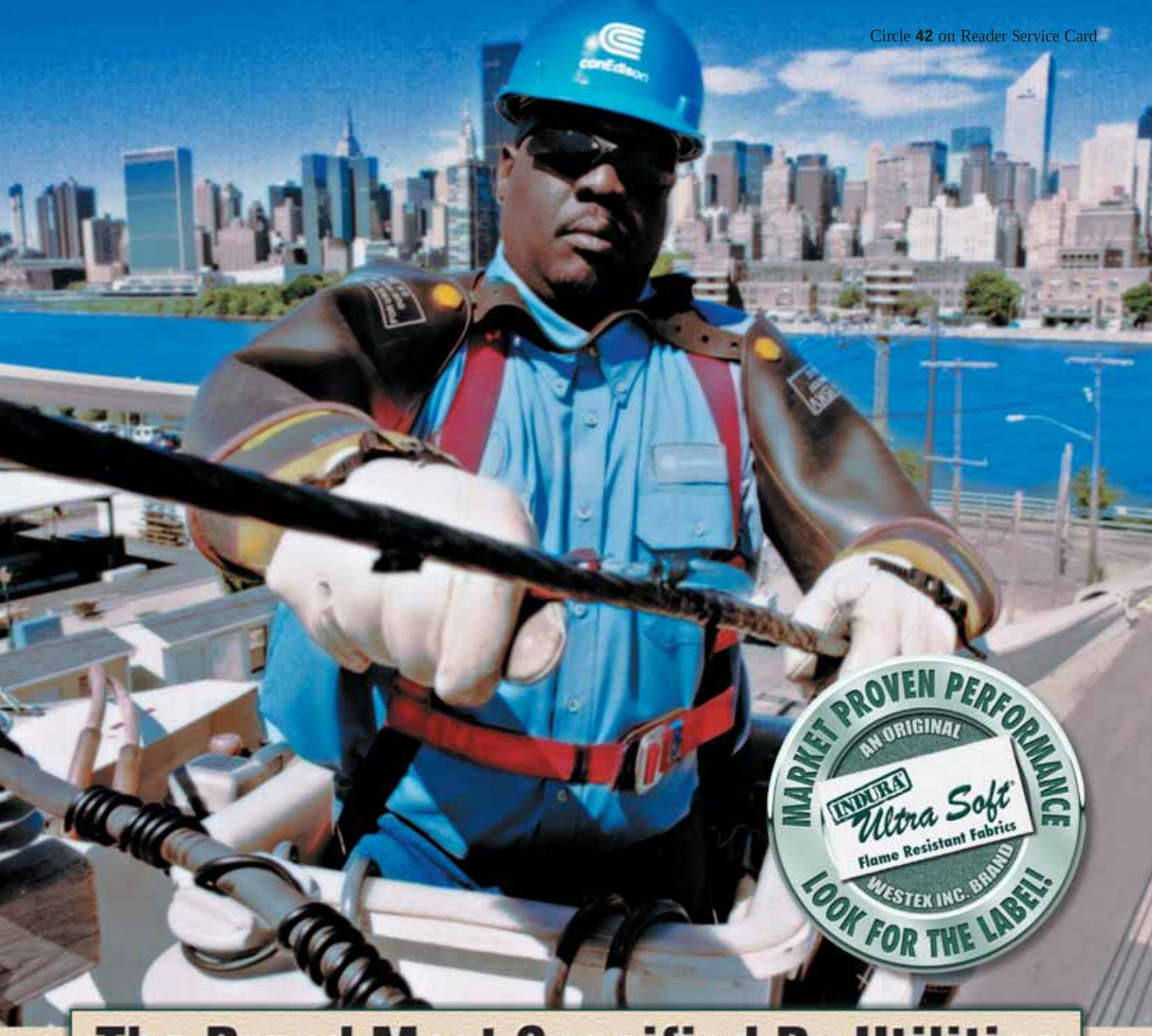
Utility enterprise-wide systems integration and technology road mapping requires a holistic approach bringing together operational needs, business applications, data and process across the utility business units. This requires a broad range of subject matter expertise covering operating practices, technology requirements, and business opportunities across the organization. The technology roadmap should support business requirements and priorities, and provide a return on investment that can be supported both internally by the affected business units and externally through rate cases and regulatory process. This requires a multi-disciplinary approach to enable deep dives into specific technical and operational areas, when necessary, to ensure an effective strategy and deployment roadmap.

Utility IT professionals are increasingly faced with information integration needs across traditional organizational boundaries. However, many of the individual business improvement opportunities are difficult for utilities to justify on their individual merits, or to accomplish in the absence of readily available hard data. A holistic approach to providing integrated data enables the utilities to realize economic benefits in a similar holistic fashion that they could not approach taken piecemeal. However, this requires planning projects that cross the traditional organizational boundaries. Different business units may have to agree on the scope, budget and control of the technology. Utility IT professionals have become accustomed with enterprise applications, but in large part for applications outside of the operational environment. Enterprise level integration for support of operational systems will require a more careful planning and execution.

Beyond economic and operational benefits of systems integration, the need for better data management and controls is also becoming a driver for enterprise level strategies. Increasingly, information is viewed as an enterprise asset, which needs to be properly managed, controlled and made available to different enterprise users and applications. For example, Geographic Information Systems (GIS) data is needed by the Outage Management System (OMS) for outage management and restoration, used by Mobile...







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...Workforce Management (MWM), needed by Customer Information System (CIS) for customer mapping, is used by systems planning and engineering in support of asset management and network analysis, is used by SCADA for world-maps, etc. Real-time equipment condition monitoring data is now being passed through SCADA to engineering and field crews for condition based inspection and maintenance activities, and used for asset management. Planning of information systems and enterprise applications require a holistic approach to address these diverse needs.

Typical components of utility enterprise information system assets include:

- T&D Planning and engineering - systems planning, maintenance management, asset management
- Distribution management – MWM, Work Management System (WMS), OMS, GIS
- T&D operations – SCADA, Energy Management System (EMS), Distribution Management System (DMS), dispatch, Demand Side Management (DSM)
- Energy supply and market operations - forecasting, bidding and scheduling, trading and contracts, settlements
- Customer service – Mobile Data Management System (MDMS), Customer Information System (CIS), call center, billing
- Administrative systems – purchasing, Accounts Receivable (AR)/Accounts Payable (AP)/General Ledger (GL), inventory, projects, Human Resources (HR)/payroll
- IT systems – desktops, servers, e-mail, portals, networks
- Communications infrastructure – plant controls, substation automation, feeder automation, advanced metering infrastructure

Enterprise wide integration brings these assets together, facilitating information access and sharing, utilization of common infrastructure and enabling applications and processes to achieve higher degrees of operational efficiency and reliability. This vision requires a strategic view to address an environment that may include many legacy applications, with no or limited integration capabilities, diverse data bases, data duplications and data quality issues, various standards and regulatory requirements, and diverse and evolving business needs.

Analysis approach

Planning, specification, design, deployment and maintenance of enterprise IT systems require significant levels of analysis and documentation that must follow a methodical approach. There are several technical approaches available, including Rational Unified Process (RUP) for technical analysis and requirements documentation, and well as KEMA's iAdvantageTM framework for project task activities, that can be tailored to specific utility requirements and operating culture. As appropriate, the supported industry standards, recommended technology stack, reference models and business practices, and tenets that will govern the information management, technology deployment and systems integration activities need to be identified.

In general, there are three broad areas of analysis and assessment to be considered:

Current state and requirements analysis - Current and the future state assessment activities should be based on the analysis of the various technology, data and process layers that encompass the solutions for an individual business application or the enterprise business needs. These layers include the infrastructure; the various vendor supplied or in-house developed business applications; the data, data access and its required security and controls; and the business processes and user functions.

Often, enterprise applications integration strategies and projects are based on the selection and deployment of information integration technologies, without much attention to the specific requirements and constraints of individual business applications and processes supporting those business functions. Technologies suitable for integration of transaction based applications, e.g., those typical in Customer Services, purchasing or administrative functions, may not be suitable for real-time and data intensive applications typical in T&D operations. The utility enterprise integration strategy needs to consider application area requirements and constraints.

Cost benefits assessment - Technology projects typically require cost and benefit justifications. Enterprise level projects impose an additional degree of complexity due to their broad reach and impact on multiple business activities. The analysis requires an understanding of business and operational benefits of the technology to often highly technical T&D and other operational facets of the business. The analysis may require assessment of strategies, options and alternatives. Deep subject matter expertise is often needed not only to perform the analysis but also to have the support and buy-in from the functional and business owners.

Qualitative and quantitative analysis should be performed based on business objectives, nature of the project and data availability. Where utility specific data is not readily available, utility industry best practices is used as a reference in assessing the benefit and cost magnitudes. The technology benefits, at a macro level, may be grouped into the following key categories: Increase Workforce Productivity; Improved Customer Services; Improve Electric Service Reliability, e.g., reduced outage frequency and duration; Increase System Operations Efficiency; Reduce/Defer/Eliminate Capital Investment. Automation and technology projects can thus be linked directly to business benefits and metrics, as an integral part of the enterprise strategy.

Cost benefit models become an effective tool for evaluation of alternative strategies and their sensitivity to schedule, capital and O&M cost variations. Advanced analysis techniques, e.g., Real Options analysis, may be deployed for support of multi-year phased projects.

Technical approach - The enterprise technology and integration strategy also requires establishing reference models for recommended technology stack and integration framework. Most utilities already have adopted a recommended position for enterprise technology stack. However, these are not fully applied as guidelines to systems and applications supporting engineering and operations. Integration reference model complements the technology stack and established recommendations for services, standards, design components, and patterns that are used in design, implementation and enhancements of integration infrastructure. Applicable industry standards and practices, e.g., Common Information Model (CIM), various Service Oriented Architecture (SOA) requirements, NERC cyber security for critical infrastructure (CIP), and other applicable standards may be considered. Systems integration requires numerous interactions internally and externally, and these interactions are typically implemented via SOA or, in other words, by consuming or providing services. ■

About the Authors

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The Story Is In the Meter

By: Tom Knutsen, Energy Consultant, Lower Colorado River Authority

Solid-state interval data recorders are the repositories of stories – the stories of the events behind them. We found errors at two metering points in the last year using interval data to discover mistakes and pinpoint the time they occurred. The first of these events was a mystery, a true "What, when, and how did it happen?" The second was straightforward –finding a loose component in a meter during a routine annual test. While the errors were embarrassing and costly, correcting them has been invaluable. So, this is also an account of managing mistakes to prevent their recurrence.

A generation and transmission utility that sells power wholesale to municipal and rural electric cooperative distribution utilities, the Lower Colorado River Authority (LCRA) also supports its customers with a key account program. At the wholesale level, LCRA delivers power to substations where it transfers ownership on the low side of the transformer. Unless the customer owns the transformer, LCRA's Transmission Services Corporation (TSC) charges for peak demand during an 11-month period. On behalf of the Electric Reliability Council of Texas (ERCOT) grid, it also assesses a fee on all transformers' average demand at the time of the ERCOT system's peak in the four summer months, June through September. LCRA's Generation Services group manages a key account program for participating customers, contracting with Texas Meter & Device of Waco, Texas, to manage participating customers' poly-phase meters. TMD installs, tests, and verifies meter accuracy annually. Hunt Power, Arlington, provides meter data services.

That background provides the setting for these two events.

Let's begin with the mysterious load drop in a municipal utility. The first person to notice something awry was a transmission billing analyst who was developing annual estimates of peak loads for wholesale electric customers' transformation and transmission billing determinants. He graphed each wholesale customer's total demand by month and saw that the peak demand for one municipality had dropped approximately 20 percent in a year. He started asking questions – "Did anyone know of a business or major building that had left?" Customer service representatives verified that the community had experienced no major changes.

An analyst in the generation group studying the data developed a simple but effective test using interval data. He compared 15-minute intervals for two years and graphed their relationship in terms of a ratio around a horizontal line of their mean. Looking at the intervals' ratio, he saw that the load began to decline in the fall of 2004. The drop was neither immediate nor steady. More analysis identified that from mid-November 2004 through September 2005, the city's metered demand had decreased from about 2.4 megawatts (MW) to 1.8 MW. At first field staff thought the city's upgrade of its distribution system from its 4,160-volt serv-

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Original setup cables and CT

ice to a 12,500 may have caused the change. The municipal's electric superintendent dispelled that theory, noting that the line had not been built. When an LCRA meter technician re-tested the meter in October 2005, he found that the shield wires surrounding the conductors from the regulator to city breaker were grounded at both ends, causing current to circulate through the meter's current transformers.

The problem stemmed from temporary service LCRA built for the city's distribution improvements. While crews installed new transformers and controls for the 12.5 kilovolt (kV) service, another group set temporary service adjacent to the permanent substation. Temporary equipment included a step-down transformer, breakers, conductor cable insulated and shielded for use on the ground, metering current transformers (CTs), and the meter with its instruments.

Proper installation of shielded cable calls for grounding only one end. In this case, the crew connected the grounds at both the regulator and breaker, causing current to circulate in both directions. The CTs see current flowing in one direction, record it, and then when current flows back, they subtract the reverse current, leaving a remainder that is less than delivered power. When the temporary equipment was set, the meter tech had followed standard practice and probed the conductors above and below their CTs but between the grounds. The readings matched, so the installation would appear to be proper.

With a shielded cable, the correct method of measurement is to probe the conductor where it is not shielded, at both the bus and relay ends. That measurement compared with a reading at the meter shows the amperage as delivered and measured. A difference between amps at the bus and at the meter would indicate a problem in the connections or grounding; for example, the meter check on the improperly grounded conductor showed 171 amps at the connections but only 147 at the CT. The grounds between the regulator and CT accounted for the difference.

Merely finding and correcting the mistake addresses only the immediate problem. To turn errors into opportunities for education, LCRA TSC's field managers have established a formal process for documenting mistakes, reviewing their causes, recommending improvements, and not laying blame except in instances involving safety violations or negligence. As the manger for maintenance services, Peter Larkam, said, "You don't want to absolve people from the responsibility of doing something right." LCRA wants to encourage its workers to report mistakes and cite corrections. To assist with this effort, LCRA TSC has engaged a consulting firm that specializes in industries where human error may lead to catastrophic results: nuclear power, hospitals, and airlines, to advise on this process. Completed studies form a library for supervisors and managers to review in order to avoid repeating mistakes. Additionally, reports are analyzed for trends that may not be apparent when examining only isolated events.

Larkam chartered a temporary team to report on the error at the municipal substation. Its key recommendations were to change the meter tests for temporary service to measure current at the regulator and breaker to ensure readings match and to develop written procedures for installing

Unplugged

Plugged

temporary substations. Those steps are at the construction and installation end. It also charged the recipients of meter data, analysts in generation services, to look at interval data for all sites after meter tests or new meters are installed, using the ratio comparison developed while looking for the lost kilowatts.

At the consumer level, the cause of the meter error occurred inside the meter. The sensor for the A Phase current transformer pulled away from its internal terminal during the meter's annual test in January 2005. No one knows how the Molex connector came unplugged. In the 2005 test, the technician checked the potential and current transformers for condition and accuracy with a phase-angle test device called a "Bird Dog." Next he removed the meter from its "A-Base" mounting, meaning it is hard-wired in place. Meters in sockets have to be pulled from their mountings; a sudden and hard tug could have loosened the connector. In this case, the tech unscrews leads, lifts the meter, and wires into bench-testing equipment in the van. All test results for 2005 came back good. The meter tech re-connected the meter into its bracket, restored power, and waited for Hunt Power to read the meter to get the first 15-minute interval. With the communication link working and the data file verified, the TMD tech completed the on-site test.

Yet sometime between bench test and mounting the sensor came loose.

During the next year's bench test, the meter was running 30 percent slow. The technician opened the cover and found the sensor hanging inside. He replaced it, and the ensuing test indicated the meter was working properly. The loose sensor caused the meter not to record current from the A-phase conductor, approximately a third of the customer's load for a year.

Even though interval data did not play in the discovery of this error's root problem, the test technique of ratio comparison verified date and time, as did the data on the meter channels recording amps and volts by phase. When our MV-90 operator learned about the loose sensor, he asked the analyst who developed the ratio comparison to look at the customer's data for 2004 and 2005. A few minutes later, the analyst returned and asked, "What happened on Jan. 21 last year at about 1:30 in the afternoon?" The graph's curve comparing the two years' intervals pegged the time the sensor failed. A second analyst looked at channels recording amps and volts and saw the A-phase registering zeroes from the time the meter went back into service. Any doubt about cause or time disappeared.

Next, we followed the example of Transmission Services. We reported on cause and recommendations, and again, improvements start at the site. First and most important, TMD has added a step for new installations and tests. After all other tests, the tech changes the face display by putting a magnet above a reed switch on the meter's circumference. The switch opens and changes the visual display from engineering units to volts by phase, verifying that all phases are operating properly. After meter tests, an analyst compares the meter's data to periods before the test – day, week, and week a year earlier. In addition, the checker looks at volts and amps if the meter is programmed to record them. Last, and farthest from the site, the programmers of our billing system have created a high-low report that we run at billing time. ■

About the Author

Tom Knutsen is an energy services consultant for the Lower Colorado River Authority (LCRA) in Austin, Texas. He and three other co-workers share responsibility for the meter and communications infrastructure, data collection, and billing data delivery for key end-use consumers served by LCRA's wholesale customers. His writings on interval data management have been published in Transmission and Distribution World and Electric Energy T&D. Before LCRA, he worked five years as a reporter for daily newspapers in Texas. He holds an A.B. in history from Yale University and a master's in communication from The University of Texas at Austin.
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Coping with Smart Metering Uncertainties

If You Build It, What Will Come?

By: Guerry Waters, Chief Technology Officer & Senior Vice President, Marketing and Strategy, SPL WorldGroup

Is mass-market advanced metering a technology whose time has finally come?

It's hard to ignore the many advantages reported by leading-edge utilities: better power forecasting, fewer unnecessary truck-rolls, satisfied consumers. Regulators are intrigued by the possibility that residential demand-response programs might reduce the need for new infrastructure. Some North American utility companies are already considering or even launching advanced metering programs for all customer classes.

Many utilities, though, are hesitant to commit to new advanced metering systems. Will they be able to recover the high costs involved? Will they find themselves on the bleeding rather than leading edge of technology? How will customers respond to a major and permanent change in the way they pay for energy? Will regulators provide long amortization periods of the additional smart metering infrastructure cost in order to lessen the impact to customers?

No one can give a truly authoritative answer to these questions. But that doesn't mean you must stand on the sidelines while others move forward with potentially cost-saving advanced metering technology. Here are some ideas that may help mitigate the risks you'll encounter in the new world of smart metering:

Risk: Advanced metering is clearly desirable, but the cost is too high.

Remedy: You may be able to change the cost/benefit equation by broadening your outlook or even adding costs.

It may be counter-intuitive, but there are times when you can move an advanced metering system from red to black by adding costs.

A good example is an advanced metering proposal built around the need for demand-response and therefore predicated on one-way meter communications. Consider the added benefits available by moving up to two-way communication: meter polling during outages, remote programming that enables customers to use new products that might be offered by the utility or by a third party.

Fortunately, the range of benefits available from advanced metering is very broad. There are tangibles, for example:

- Fewer meter readers, which means lower total costs for salary, benefits, and workers compensation.
- Remote rather than expensive and occasionally risky on-site disconnects.
- Less wasted time in attempts to pinpoint the size and source of an outage.
- Better accuracy in the actual meter readings.

There are semi-tangibles, like less customer dissatisfaction—and fewer calls to the call center—concerning estimated meter reads. And there are intangibles, like customer—and neighbor—gratitude on discovering that, while the family was on vacation, the utility detected an unexpected and significant upswing in "consumption," and as a consequence, gained emergency access to the residence and fixed a gas leak.

Fortunately, others have already gone down the path of benefits estimation. There's considerable information available (see sidebar) that will help you build a business case that includes a comfortable cushion to cover the inevitable unexpected costs.

Risk: Pilot program results are misleading.

Remedy: If a pilot can't reflect real-life conditions, substitute the research and experience of others.

Technology annuls are full of stories about successful pilots followed by unsuccessful products. That's because it's hard to narrow the gap between a test and real life.

Let's take the example of a utility that wants to limit capital investment in new infrastructure. It already knows that large industrials will time-shift electricity use in response to a price signal. Might consumers do the same? And might that obviate or at least postpone the need for new construction?

That's a question to which a pilot might easily provide the wrong answer.

Here's why. A pilot must first recruit or assign participants. Either way, most utilities feel it necessary to protect pilot participants from overly harsh financial consequences. So they use rate structures that make it easy for participants to save money through time-shifting. Or they guarantee that participation won't increase bills.

That's not a real-life demand-response program. That's a game.

Compounding the problem is that, by definition, pilots are interesting. Often, those willing to sign up for a pilot program of energy conservation have more of an environmental concern than the majority of a utility's customers. Additionally, participants have positive feelings about being

singled out. They enjoy their contacts with utility staff. They may develop a commitment to the project's success. It's hardly a surprise, then, that after six months or so, time-shifting has occurred.

Rolling out this same project to the public at large as a permanent change in energy billing may get markedly different results. Customers jaded by less-than-successful competitive energy programs may greet this new initiative with skepticism. They may find the supposed time-shifting savings to be elusive or difficult to achieve with the appliances currently in place. They may find the relatively small savings available are simply not worth the effort.

Complicating the problem are likely differences between long-term and short-term behavior.

- Will an initial rise in call center activity persist? Rise? Fall over the long term?

- Will initial concern about electricity prices and availability give way to long-term "business as usual"? The history of gasoline prices suggests that higher energy prices produce initial consumer alarm and consideration of measures like car pooling and using public transportation. Few, however, appear to make such changes on a permanent basis. And while programs like demand-response could well affect the appliance features consumers demand, the homeowner's appliance replacement cycle can be eight to 15 years or more. Add that to the time needed for manufacturers to bring such equipment to market and you have a gap between program implementation and effect that likely exceeds utilities' and regulators' time horizons.

- Will consumers seek regulatory relief from residential demand-response programs that require them, every day, for the rest of their lives, to find out the price of electricity, then adjust their behavior—and the behavior of family members—accordingly? Is there any other aspect of modern economic life that imposes such a burden on consumers' time?

Without several years of experience, no one can give accurate answers to such questions. But the answers could turn a cost-saving program into one that loses money.

Fortunately, there are ways to avoid the misleading-pilot trap. If your goals will require an advanced metering program that cannot be accurately tested in a pilot, then avoid the pilot altogether. There are a number of studies and real-life examples already available (see sidebar) that should give you enough information, at a minimum, to put parameters around the range of likely customer reactions to an advanced metering program.

Risk: The savings in your business case don't materialize.

Remedy: Get commitments to the actions that will produce the business case numbers before you implement the program.

Developing a valid business case is no easy task. Strategists may be able to see clearly three or four steps down the road; but that unseen fifth step may be the one that really counts.

Let's take an example: an advanced metering program aimed at reducing the number of unneeded truck rolls in response to outage calls from customers. At some utilities, the "OK on arrival" outcomes of outage calls can run as high as 80 percent. Clearly, an advanced metering system that permits "pinging" the meters all around a reported outage can dramatically reduce unneeded responses to problems like blown fuses or other inside-the-building problems.

No business-case developer will project savings of 80 percent of the total costs of field crews and equipment. The costs of staff retraining and re-education will be included. So will amortization schedules for existing (and potentially unneeded) equipment and penalty charges for existing supplier contracts. The business case will allow for the dispersion of crews throughout large rural service territories and for the costs of supervising remote crews.

But will the business case adequately account for the potential consequences of fewer crews and trucks available to respond to widespread

Case Studies and Other Resources for Estimating Advanced Metering Benefits

Patti Harper-Slaboszewicz, "AMR Business Cases Stronger with MDM and DR," UtiliPoint, September 28, 2005. **http://amimdm.com/site/modules/articles-7/index.php?id=9**

Mid-Atlantic Distributed Resources Initiative (MADRI) Toolbox. **http://www.energetics.com/madri/toolbox/**. Permits downloads of case studies, PUC filings, and other documents highly relevant to U.S. utilities.

"If RTP Is So Great, Why Don't We See More Of It?" University of California Energy Institute, Spring 2006 (select the Spring 2006 edition of the CSEM Newsletter from **http://www.ucei.berkeley.edu/**). Offers alternatives to advanced metering that may accomplish similar objectives.

Ben Long and Bryan J. Scott, "Is Real Time Pricing Worth the Effort?

A New Study Examines Impacts of Utility Real Time Pricing Programs," UtiliPoint, March 9, 2005. **http://powermarketers.netcontentinc.net/newsreader.asp?ppa=8kowu%5DZlrlhnmkUTfct%3EEvbfel%5D!**

"Residential Pilot to Test "Smart Metering" for Pepco's DC Customers: Advanced Technology, Innovative Rates Could Help Reduce Customer Bills," June 19, 2006. **http://www.pepco.com/welcome/news/releases/archives/2006/article.aspx?cid=690**.

This is just one of several examples of pilot programs whose progress can be tracked on individual utility websites.

Federal Energy Regulatory Commission Staff, "Assessment of Demand Response & Advanced Metering, Docket AD06-2-000, August 2006. **http://www.ferc.gov/legal/staff-reports/demand-response.pdf**. 200+ pages of excellent background.

McKinsey & Company has developed a "plug in your numbers" valuation model to help utilities assess AMI project feasibility. Access the model and user guide from **http://www.mckinsey.com/clientservice/electricpowernaturalgas/service_ami.asp**

The Demand Response and Advanced Metering Coalition (DRAM) website features a number of helpful articles and references, including a case study analysis of Georgia Power program. **http://www.dramcoalition.org**

The Regulatory Assistance Project (RAP) offers a number of policy-oriented papers on metering and demand response. **http://www.raponline.org**.

Britain's Office of Gas and Electricity Markets (ofgem) has several helpful position papers that offer perspectives on smart metering from the European Union and throughout the English-speaking world; search on "smart" and "meter" on **www.ofgem.gov.uk**.

storm-related outages? Can it accurately foresee the effect of fewer field service crews on reliability measurements? Can it take into account the potential reactions of customers and regulators to slower power restoration? Can it gauge the reactions of other utilities that lend crews to respond to a neighbor's emergency only to discover that the neighbor cannot return the favor? Will it correctly estimate the size and consequences of a unionized field force's organized response?

The strategist may see those questions as unanswerable. But a field crew manager might argue successfully that, precisely because they are unanswerable, the utility should adopt a "go slow" attitude about making changes like reducing the number of field crews. If the business case depends on crew reductions, its numbers just got blown out of the water.

A similar situation might prevail even if the business case includes only reductions in overtime truck rolls. Field workers frequently see overtime as a benefit, and they may count on it as part of their total annual income. Eliminating or reducing overtime in this case is equivalent to a pay cut. Unionized crews may take exception to the plan and demand compensation or other work-rule changes that could negate some of the business case's projected savings.

Avoiding unforeseen "second guessing" like this means involving managers throughout the utility. But testing a business case with a wide audience runs a high political risk. Premature rumors can tie management hands and reduce alternatives before they're carefully considered.

When it comes to involving more people in the advanced metering business case, utility strategists are clearly caught between a rock and a hard place. But most will find that the risks of too much communication are smaller than the risks of too little.

Risk: Hardware and software investments turn out to be unneeded.

Remedy: Evaluate existing systems for their possible contribution to an ultimate advanced metering system.

A number of utilities have issued Requests For Information (RFIs) about vendors' advanced metering capabilities. A few have moved to the proposal and contract stages. As a result, vendors are introducing new products and entering new alliances to respond to a perceived market demand.

This process has only just begun. New entrants will come into the market for at least the next few years. They will have new ideas that could turn out to be more suited to your specific situation or possibly less costly.

Some utilities simply cannot delay implementing new, complete end-to-end advanced metering systems. Others, however, may be able to make progress by using pieces of existing systems. Ask your existing vendors, for instance, the cost of:

- Adding substantially more customers (i.e. residentials) to an existing commercial and industrial interval-billing program.
- Developing more robust integrations between existing outage

management and mobile workforce applications.
- Adding time-of-use or one-way communications capabilities to existing meters.

It may also be possible to piggyback advanced metering functions onto an existing quest for a new or replacement outage or billing solution.

Analysts predict most utilities will eventually want to handle advanced metering data in a separate meter data management application. But you may want to take an interim step that lets you test the benefits of your direction before you commit to a significant addition to your IT structure.

Consumer behavior is unpredictable. So are the long-term consequences of a major change in the way people pay for a fundamental building block of contemporary life. But utilities cannot afford to let unknowns paralyze them. Communities' escalating energy needs plus the environmental consequences of wasted energy and infrastructure are simply too important for a "wait and see" approach to advanced metering.

Advanced metering promises far too many benefits to simply ignore. Risk mitigation approaches like the above may be the best way to add appropriate caution to issues on which most utilities will need to act sooner rather than later. ■

About the Author

Guerry Waters has more than 30 years experience in global information technology strategy, organization, architecture, and business-driven IT solutions. He has been SPL's Senior Vice President of Marketing and Strategy since November 2000.

Prior to joining SPL, Mr. Waters was Vice President of Energy Information Strategy at META Group, where he focused on customer management and alignment of the information technology function with the energy lines of business. His previous responsibilities in the energy industry included the positions of CTO and Director of Technology Strategy and Engineering at Southern Company.

Mr. Waters' educational background includes concentrations of studies in business, technology and extensive course work and studies in management, strategy development, and implementation planning. He is a frequent speaker and writer on issues surrounding the transformation of IT and creation of customer-related strategies and solutions in an increasingly competitive global market.

"The future of the utilities market lies in the ability of companies to innovate and adapt to today's changing markets. If companies are to succeed in the utilities sector, they must adopt innovative solutions capable of providing them with competitive advantage."

Maintenance Programs for MV & HV Power Circuit breakers

By: Fouad Brikci, Ph.D., Zensol Automation Inc.
By: Emile Nasrallah, P.Eng., Circuit Breaker Specialist

Preface

In a previous article, we overviewed the circuit breaker maintenance practices presently in application, including a listing of some of the important tests in use, with reference to the applicable international standards.

All these tests have to be coordinated and well planned since the collection of data is spread over a relatively long periods of time. In order to achieve these goals, we need to set up a maintenance program.

In the present article you will find a summarized description of a typical maintenance program's structure ***(Fig 1)*** and its main components. We hope it will give maintenance planners managers enough insight to shape their breaker maintenance programs or to initiate one if it does not exist yet.

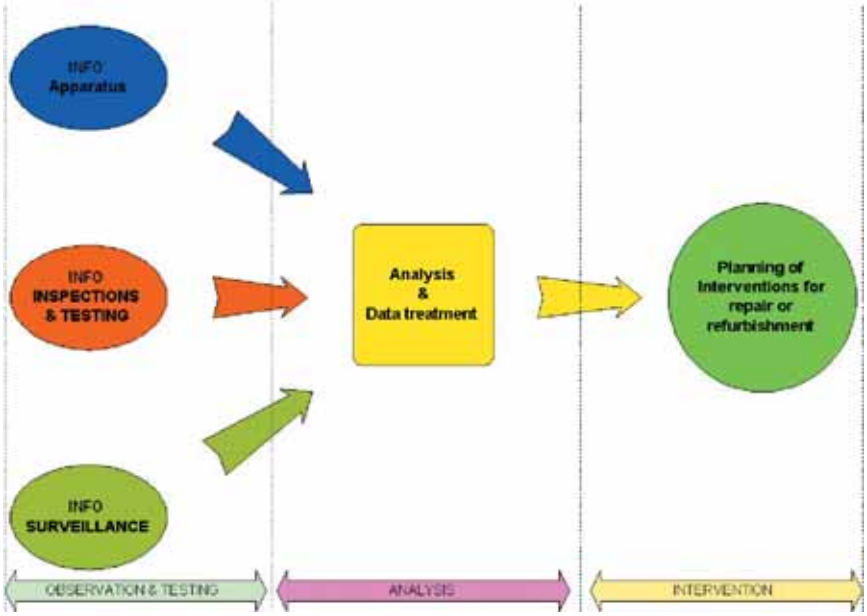

Fig. 1: Maintenance program's typical structure

Introduction

Because of its protective role, the circuit breaker plays an important role in transmission and distribution networks. If it breaks down the impact on the network can be serious. In addition to the damaged equipment, the cost of current interruption can be tremendous, since current interruptions are subject to severe penalty clauses in Electrical energy supplying contracts. Not to mention compromising the substation personnel safety, as they would be at risk of injury.

Inspection and periodicity Table ***Fig. 2: Inspection and periodicity Table***

Type	Description	Periodicity
Routine Inspection (RI)	Thermography Visual inspection (insulators, leaks, general condition, etc.) Operation counter Pressure gauges	1 year
Limited Inspection (LI)	In addition to RI it includes: Leaking tests Contact resistance test Timing test	4 years
Provisional Inspection (PI)	In addition to LI it includes: Specific verifications (Heating, wiring, timers, pressure switches, Filters, Safety switches, Fuses, Auxiliary switches, etc.) AC Insulation test Functional test Antipumping test	8 years
Complete Inspection (CI)	In addition to PI it includes: Open inspection of one interrupting module Open inspection of the mechanism any other inspection specific to the type of the breaker	1000 operations

The best practice to avoid breakdowns then, is to apply proper maintenance. Since the breaker is like a black box, the only way to assess its condition with certainty is to take it apart. This can be a costly business, especially if it is not necessary.

This leads to the necessity of applying a multitude of maintenance actions (inspections and tests), in order to collect enough information on the actual condition of the breaker, which in turn permits a decision to proceed with repairs in time.

Maintenance Actions

The maintenance of circuit breakers relies then, on the application of a number of actions, called maintenance actions. These actions can range from a simple reading, like an operation counter, to a full inspection including disassembly of a major part, as an interrupter chamber for example.

Fig. 3: Breakers Database

No	TYPE	MANUFACTURER	S/N	TECHNOLOGY	YEAR	SUBSTATION	POSITION	INSTALLATION	KV	A	KA	APPLICATION	K FACTOR
00001	PK4A	DELLE-ALSTHOM	36070R1	AIRBLAST	1970	MAKATA	300-01	1971	330	2000	31	LINE	1
00002	PK4A	DELLE-ALSTHOM	36070R2	AIRBLAST	1970	MAKATA	300-02	1971	330	2000	31	LINE	1
00003	PK4B	DELLE-ALSTHOM	36070R3	AIRBLAST	1970	MAKATA	300-03	1971	330	2000	31	LINE	1
00004	PK4B	DELLE-ALSTHOM	36070R4	AIRBLAST	1970	MAKATA	300-04	1971	330	2000	31	LINE	1
00005	PK4B	DELLE-ALSTHOM	36070R5	AIRBLAST	1970	MAKATA	300-05	1971	330	2000	31	LINE	1

Maintenance actions on circuit breakers are numerous and diverse, but they all serve to keep a close eye on the breaker's condition to correct it before breakdowns occur.

Some of these actions have to be repeated on a periodic basis. The information has to be recorded and analyzed to reach a verdict. ***Fig 2***. Inspections and periodicity table, shows a list of possible inspections classified according to four categories of inspections:

- Routine inspections
- Limited inspections
- Provisional inspections
- Complete inspections

Each family of circuit breakers needs to have its specific list of inspections and periodicities. All these actions need to be planned and coordinated. Setting up a program called "Maintenance Program" does all of this.

Maintenance Program

In essence a maintenance program serves to:

- Coordinate the maintenance actions on a timescale;
- Collect data on the actual condition of the breaker
- Organize the collected data for analysis;
- Analyze the collected data;
- Plan intervention if needed.

Maintenance Program's Elements

In order to reach the above-mentioned objectives, the program has to rely on the following elements:

- Planning;
- Observation & Testing (Data collection);
- Analysis;
- Planning
- Intervention.

Observation:

This is the part that collects information from all sources. The information collected is organized in databases. Some of these databases are described as follows:

Breakers Database ***(Fig 3)***: First of all we need to know our breakers. This is achieved by maintaining a database of installed equipment. This database should contain, in addition to other required information, the following:

- Type;
- Manufacturer;
- Serial number
- Technology (SF6, Air blast, Oil, etc.);
- Year of manufacture;
- Location;

Fig. 4: Tests Database

Name	Description	Breaker Type	Application	Standards
ContactTiming Test	Measures the time from the order initation to contacts close or part	All	Overall breaker operation	IEC
Travel & Velocity Test	Traces travel and velocity curves	All	Overall breaker operation	IEC
Contact Resistance Test	Measures the contact resistance between to parts meant to conduct current	All	Electrical conductivity	IEC
AC Insulation Test	Measures the insulation between open contacts and between line and ground	All	Electrical insulation	
Oil Dielectric Test	Measures the dielectric carachteristics of insulation oil	Oil breakers	Electric Insulation of medium	IEC
Oil gas analysis Test	Measures the gas content in the insulation oil	Oil breakers	General quality of medium	IEC
Water Content Test	Measures the moisture content in the insulation medium	All	General quality of medium	
SF6 By-Products Test	Measures SF6 byproducts level in SF6 insulation gas	SF6 breakers	General quality of medium	
SF6 Mixture percentage Test	Measure the percentage of SF6 in insulation gas mixture	SF6 breakers	General quality of medium	
Auxiliary Circuits Insulation Test	Measures the insulation of the low voltage control circuits	All	Electrical insulation	IEC
First Trip Test	Measures the contact timing at first trip	MV breakers	Breaker operation	
Dynamic Contact resistance Test	Measures the contact resistance continously since the first contact make of a moving contact until the contact's stop	All	State of contact wear-out	
Vibration Test	Measures the vibration signature of a circuit breaker	All	Overall integrity	
X Ray Test	Takes an X-ray photo of the inside of closed subassemblies	All	Breaker integrity	
Ultrasound Test	Cheks for crackes in insulatures	Insulators	Product integrity	
Capacitance Test	Checks the capacitance value on capacitors used on breaker (grading, coupling, etc.)	Capacitors	Product integrity	
Air pressure consumption Test	Measures the air consumption of an operation or cycle of operations	Air blast breakers	Breaker operation	
Infrared Tempurature Test	Measures temperature of parts by infrared device	All	Electrical conductivity	
Tightness Test	Checks the tightness of the insulation medium	All	General quality of medium	

- Electrical characteristics (Voltage, Amperage, Breaking capacity, making capacity, etc.);
- Application;
- Date of installation;
- Various information, proper to the breaker itself.

Tests database ***(Fig 4)***: This database contains a list of required inspections and periodicities (prescribed time periods between successive maintenance actions to be repeated systematically) to be conducted on the breakers.

Collected data database ***(Fig 5)***: This database organizes, for each breaker, the data collected in various inspections, and it may include:

- First test sheets results;
- Inspections results over time;
- Repair interventions;
- Operation Counter
- Pressure gauges readings
- Temperature readings
- Timing readings
- Insulation readings
- Travel Velocity readings
- Contact resistance readings
- Oil quality checks
- Moisture measurements
- SF6 by products measurements
- Contact condition inspection (following a complete inspection for example)
- Incidents;
- Etc.

This information serves primarily to conduct an analysis in order to determine the type and urgency of maintenance interventions. It also serves as historical data for future statistical and durability studies.

Inspection and Tests Planning:

This is the part that organizes and coordinates the inspection sequences so the maintenance people can prepare the required maintenance actions in advance (Purchasing department, Warehouse, maintenance teams, operators, etc.). to increase efficiency in collecting information. The following figure (Fig 6) gives an idea on a possible course of inspection planning.

Fig. 5: Collected data Database

BKR S/N	TYPE	INSPECTION	TEST	RESULTS	DATE	OPERATOR
23458	OIL	IP	ContactTiming Test	Report433	04-Jul-99	LMM
23458	OIL	IP	Travel & Velocity Test	Report434	04-Jul-99	LMM
23458	OIL	IP	Contact Resistance Test	Report435	04-Jul-99	LMM
23458	OIL	IL	AC Insulation Test	Report321	18-May-01	HJE
23458	OIL	IL	Oil Dielectric Test	Report322	18-May-01	HJE
23458	OIL	IL	Oil gas analysis Test	Report323	18-May-01	HJE
23458	OIL	IL	Moisture Content Test	Report324	18-May-01	HJE
36070R1	Airblast	IP	ContactTiming	Report201	09-Sep-02	AKH
36070R1	Airblast	IP	Contact Resistance	Report202	09-Sep-02	AKH
36070R1	Airblast	IP	AC Insulation	Report203	09-Sep-02	CDU
36070R1	Airblast	IP	Moisture Content	Report204	09-Sep-02	CDU
36070R1	Airblast	IP	Auxiliary Circuits Insulation	Report205	09-Sep-02	CDU
36070R1	Airblast	IP	Capacitance	Report206	09-Sep-02	CDU
36070R1	Airblast	IP	Air pressure consumption	Report207	09-Sep-02	CDU
36070R1	Airblast	IP	Infrared Temperature	Report208	09-Sep-02	AKH
36070R1	Airblast	IP	Tightness	Report209	09-Sep-02	CDU

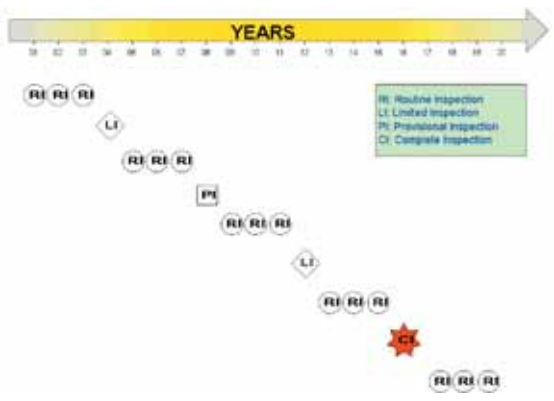

Fig. 6: Planning

Plan to attend...

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BKR S/N	Analysis Report No	Advisory	PRIORITY	DEADLINE DATE	ANALYSIS DATE	ANALYST
23458	Report1	Advisory 1	1	01-Nov-06	07-Jul-06	GHI
23459	Report2	Advisory 2	1	01-Nov-06	07-Jul-06	GHI
23460	Report3	Advisory 3	1	01-Nov-06	07-Jul-06	GHI
23461	Report4	N/A	2	15-Oct-08	07-Jul-06	GHI
23462	Report5	N/A	2	15-Oct-08	07-Jul-06	GHI
23463	Report6	Advisory 3	3	31-Dec-08	07-Jul-06	GHI
23464	Report7	Advisory 110	3	31-Dec-08	07-Jul-06	GHI
23465	Report8	Advisory 2	3	31-Dec-08	07-Jul-06	GHI
23466	Report9	Advisory 34	4	01-Jun-09	07-Jul-06	GHI
23467	Report10	Advisory 1	4	01-Jun-09	07-Jul-06	GHI
23468	Report11	Advisory 22	4	01-Jun-09	07-Jul-06	GHI
36070R1	Report12	Advisory 31	3	31-Dec-08	25-Aug-06	RTY
36070R1	Report13	N/A	3	31-Dec-08	25-Aug-06	RTY
36070R1	Report14	N/A	3	31-Dec-08	25-Aug-06	RTY
36070R1	Report15	N/A	3	01-Jan-09	25-Aug-06	RTY
36070R1	Report16	Advisory 11	7	31-Dec-09	25-Aug-06	RTY

Fig. 7: Analysis Database

Analysis

Teams of highly trained engineers and technicians process all the information gathered in the previous sections and stored into well-organized databases. These teams have the responsibility to reach a verdict based on the available information, and determine the required actions and priorities. This information is put into a specific database, Analysis database ***(Fig 7)*** that is used to prepare interventions.

This database has to contain:

- Breaker serial No, to identify the equipment being analyzed;
- Analysis report No, that details the findings and recommendations;
- Advisory No, if any;
- Priority level of each recommendation;
- Deadline date for the intervention;
- Analysis date;
- Analysts names;
- Various required information, etc.

Advisory:

Advisories are reports that inform the maintenance manager on what to do and on which equipment. It contains, at least:

- A list of concerned breakers;
- A list of actions to do;
- A description of the reasons (reference to Analysis report);
- A list of parts;
- A list of special tools;
- Drawings and instructions;
- Etc.

Intervention:

Once the advisory is initiated, interventions can now be planned.

For example the result of a complete inspection of an interrupter module may reveal a critical condition that may require an intervention program on all similar breakers.

This requires coordination between network administration and maintenance teams. A list of to-do actions, parts and special tools must be determined, not to mention training, quality assurance, budget cost control, etc.

BKR S/N	Action plan	Teams	Schedule	Start date	End date	Completion date	Manager
23458	To do list1	1	Plan1	07-Jul-06	01-Aug-06		ALH
23459	To do list2	1	Plan2	07-Jul-06	01-Aug-06		ALH
23460	To do list3	1	Plan3	07-Jul-06	01-Aug-06		ALH
23461	To do list4	2	Plan4	07-Jul-06	01-Aug-06		ALH
23462	To do list5	2	Plan5	07-Jul-06	01-Aug-06		ALH
23463	To do list6	3	Plan6	07-Jul-06	06-Aug-06		ALH
23464	To do list7	3	Plan7	07-Jul-06	06-Aug-06		ALH
23465	To do list8	3	Plan8	07-Jul-06	06-Aug-06		ALH
23466	To do list9	4	Plan9	07-Jul-06	06-Aug-06		ALH
23467	To do list10	4	Plan10	07-Jul-06	06-Aug-06		ALH
23468	To do list11	4	Plan11	07-Jul-06	06-Aug-06		ALH
36070R1	To do list12	3	Plan12	25-Aug-06	30-Nov-08		GWE
36070R1	To do list13	3	Plan13	25-Aug-06	30-Nov-08		GWE
36070R1	To do list14	3	Plan14	25-Aug-06	30-Nov-08		GWE
36070R1	To do list15	3	Plan15	25-Aug-06	30-Nov-08		GWE
36070R1	To do list16	7	Plan16	25-Aug-06	30-Nov-08		GWE

Fig. 8: Breakers Database

Once the intervention is completed, keeping record of it is crucialmatter. Every corrective action or intervention on the circuit breaker has to be recorded for comparison and future analysis. A part's repetitive failure for example may raise concerns on more critical problem or a design flaw. A breaker's history has to be available for reliability studies; this may influence the future of a circuit breaker family (systematic replacement or refurbishment).

The Intervention database ***(Fig 8)*** keeps record of such information, it must contain:

- The breaker's serial No;
- The action plan and schedule;
- Technical team assigned;
- Start date;
- Deadline end-date;
- Date of completion;
- Manager name;
- Etc.

Conclusion

As we mentioned from the beginning, the present article gives the basics of setting up a maintenance program. Detailed discussion is not relevant here, since we are dealing with a great deal of information. The following figure ***(Fig 9)*** recapitulates briefly as follows:

Information from the breaker's database and Tests database lead to collect information in Data database. This data serves to conduct a thorough analysis, leading to maintenance interventions. Interventions meant to happen before any breakdown occurs.

And last but not least, as it is obvious that any relational database can do the job, we can find many programs on the market that are specifically designed for this purpose. It is the task of specialized personnel to determine the need versus the program's capability in order to reach the perfect choice.

Bibliography

The present article is based on our personal experience with Hydro-Québec's maintenance program model. ■

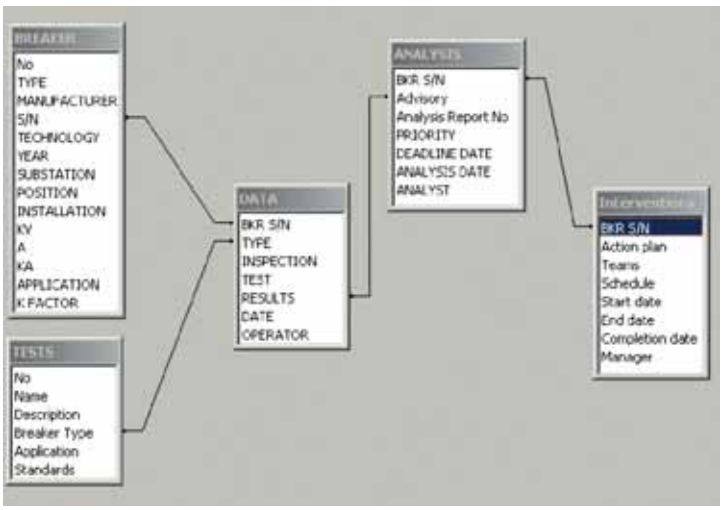

Fig. 9: Breakers Database

About the Authors

Dr. Fouad Brikci *is the president of Zensol Automation Inc. He was the first to introduce the concept of truly-computerized test equipment in the field of circuit breaker analyzers. As a former university teacher in Ecole Polytechnique — Algiers and CNRS - LAAS researcher in France, Dr. Brikci has developed experience in the fields of electronics, automation, and computer science. Most activities were focused on the industrial application of computers. Among his achievements are the development of fully comput¬erized measuring systems for quality control in circuit breaker manufacturing, laboratories, and maintenance services of electric utilities. Dr. Brikci holds a PhD in Electronics and a Master in Sci¬ences in EEA (electronics, electrotechnics, and automation) from the University of Bordeaux, France.*
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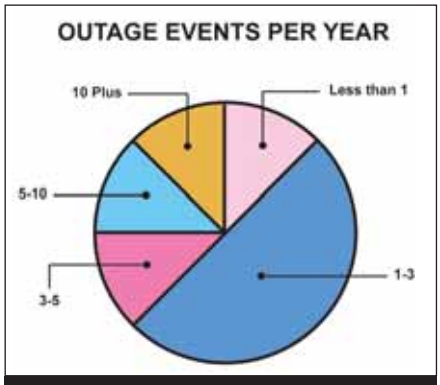
Emile Nasrallah *is an electrical engineer specialized in Power circuit breakers maintenance. Since graduation in 1984 he worked as a field engineer. In1990 he joined the worldwide circuit breaker manufacturer GEC ALSTHOM as a specialized field engineer.*
In 1997 he became the manager of MV & HV circuit breaker SF6 division of ALSTOM, responsible of technical support, maintenance and training for SF6 circuit breakers. In 2001 he became manager of Air blast circuit breaker division for AREVA. He was in charge of the Air blast (PK and PKV) refurbishing program in partnership with hydro-Quebec and introduced a unique administration system for the program (average of 35, 735 kV PK air blast circuit breaker per year). In 2005 he joined General Electric Company of Canada as a senior circuit breaker specialist and is in charge of the circuit breaker division of the Montreal service centre, responsible of the remanufacturing program for Oil circuit breakers

The 'Power' to Perform – Are Storm Centers Doing Their Best?

By: John Kullmann, Vice President, Macrosoft, Inc.

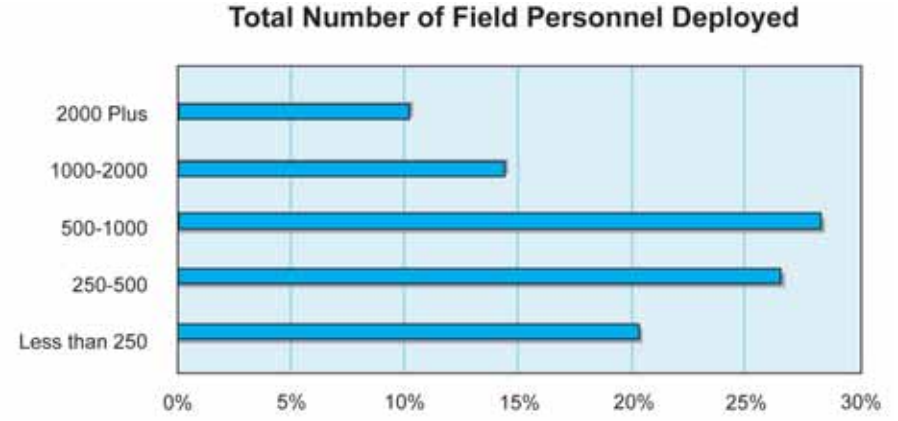
Imagine the impact of a large scale power outage ... dysfunctional appliances, jammed elevators, darkness..... Life could get chaotic or even come to a standstill. In today's world, power has become the oxygen of our working lives. With the increasingly severe weather conditions - hurricanes, thunder-storms, tornadoes, snowstorms, ice storms, landslides, wildfires, and more, how well prepared are the utility companies in supplying power with least interruption? How efficiently are emergency situations being handled by utilities? Can technology play a vital role in enhancing their efficiency?



87% of participants indicted they have at least 1 major outage every year

People are always looking for faster (if not instant!) and reliable solutions to keep pace with their lives. Their expectations from utility companies are higher than ever before. This sense of urgency has grown out of the advancement of technology which has enabled the crunching of time, effort and resources to achieve far greater results. It is not an exaggeration to say that the measure of customer satisfaction has shifted from days to hours/minutes. This puts greater pressure on the utilities to live-up to their customers' expectations.

Says David Wakeman Manager, Distribution Operating, Ameren UE, – There is a trend in business toward automation for increased



53% of the respondents reported having over 500 field personnel deployed during a large scale restoration event

productivity, information availability, and information sharing. Utility storm restoration efforts can also benefit from this approach. We have migrated away from manual tracking of resources and crews, to spreadsheets, and now to an automated system. The result of this migration has been greater efficiency in tracking resources and an increased capability in reporting after the fact. We expect to continue to yield benefits from this automation technology when managing large restoration efforts.

Macrosoft Inc., a New Jersey based global software solutions organization, studied the restoration practices of utility companies during emergency situations and measures adopted by them to quickly assemble the available resources, deploy them effectively, manage and track them -- before, during and after the event. During the period Jan-Feb 2006, a survey was conducted involving over 100 storm center leaders from utility companies to understand common best practices and pain-points which can be effectively addressed.

The report highlights the importance of standardizing operations and leveraging technology to enhance efficiencies before, during and after the event.

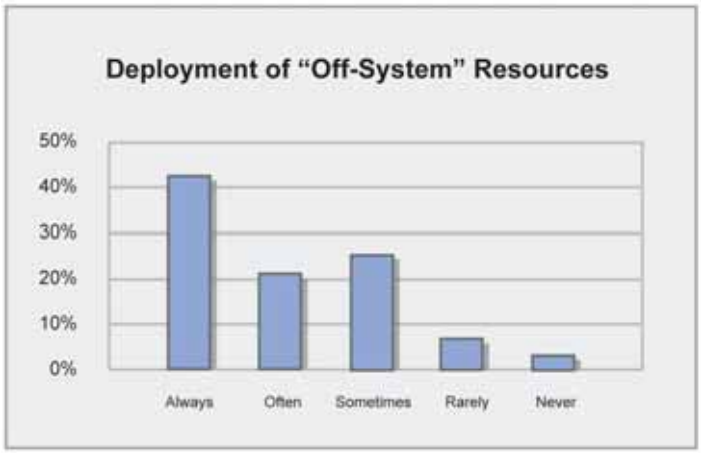
Some interesting findings that emerged from the survey include:

- Information on regions that are most affected by emergency outages
- Number of personnel deployed during various restoration events
- Use of technology in managing resources and teams during emergencies

In the first step towards looking at the challenges faced by utilities in North America, a study of the historic patterns of occurrences and their reasons would be but logical.

If you are living in the Mid-Atlantic, Midwest or Northeast regions, you are more likely to experience frequent power outages. The survey reveals that the outages in these regions occur from once to three times a year and could also go up to five times. From the survey's point of view, a 'large-scale emergency outage' can be understood as an event that affects greater than 5% of a utility's customers for a period exceeding 24 hours. The magnitude of the outage is significantly high to necessitate deployment of a large work force in restoring services.

While people in other regions may take heart from it, Southerners probably have different woes! Though utilities in the Southern regions face fewer outage situations a year, their customers endure longer durations of each outage. A whopping 43% of the utilities polled from here indicated that each of these outages last 5 days or more.



95% of the respondents said that their organizations make use of contractor and mutual assistance resources during storm restoration

Reflecting on the causes of these outages from a national perspective, 68% are due to ice, thunderstorms and winds.

Resources & Challenges:

The primary challenge utility companies face in major emergency situations is resource management and logistics. Resource management comprises identifying people & equipment requirements, procuring sufficient numbers, managing optimal allocation, and responsibility for the well-being of deployed resources.

The number of people deployed in a restoration effort can range from 500 and go upwards of several thousands during large scale outages. More than half (over 53%) of the utilities surveyed deploy at least 500 people when faced with major crisis situations. Personnel are teamed into smaller groups to manage situations at different locations in a region. With multiple teams operating across the service territory, utilizing all the resources to their optimum becomes increasingly difficult.

Some of the common challenges faced while managing resource teams during a large-scale event include accessing the damage to prioritize resource allocation; determining the quantity, as well as, availability of required resources; tracking resources, who they are, what equipment they have, and where they are located; managing logistics--lodging, meals, staging, supplies, etc.; integrating contract and off-system teams when necessary.

It is not always that utilities have enough manpower resources to handle exigencies. Most often than not, they help one another in sharing their teams. Associations like the EEI and regional mutual assistance organizations are the forerunners in facilitating cooperation between utilities and their common contractors. It is under such circumstances that standardization of processes becomes imperative to achieve greater efficiencies.

With hundreds and possibly thousands of people working in multiple teams at different locations, storm managers are under extreme pressure to exactly know who's working where and what their resource needs are. Logistics is identified as the prime challenge for

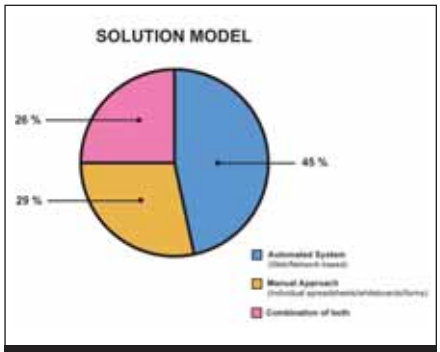
utility companies in dealing with emergency restoration situations.

Some critical concerns in handling logistics include preparing meals & lodging facilities, identifying and readying of staging areas, supplying fuel and materials, maintaining communication, coordinating safety/security/ medical treatment.

Utilities set up staging areas to house the restoration teams, their equipment, and materials stores. Lodging is an additional attribute that can be associated with a staging area. While 77% of the companies set up staging areas, 68% of them establish up to 5 staging areas in an event. 20% set up approx. 10 staging areas.

Some of the common challenges with regard to staging areas are availability of space to board & lodge the teams, parking of vehicles, meeting spaces. Unless properly planned and utilized the staging areas could get highly congested hampering the restoration work. Hence, identification and prioritization of staging areas well in advance is a critical task for the utility companies. Additionally, it was noted that securing lodging accommodations for restoration workers present a significant challenge.

Manual vs. Automated Systems:



A majority of companies still use manual spreadsheets, white boards or forms to track and manage people and equipment resources during and emergency outage.

Despite being in a hi-tech world, a majority of the companies do not use automated systems, but still follow the traditional ways of using spreadsheets, white boards, or forms to track and manage their resources. 55% report that they rely on manual or semi-manual systems. Data from the survey indicates that utilities located in geographic regions where events occur with greater frequencies are more likely to use an automated approach to emergency resource management. This is evident from the fact that 71% of utilities from the Mid-Atlantic, Midwest and Northeast regions (where events occur with greater frequency, but less duration) rely on a combination of automated and semi-automated systems as compared to 53% of the organizations from the Southern regions (where events occur with less frequency, but greater duration). Utilities that face less frequent, but potentially more severe events are not as well automated as companies that face more frequent, but often less severe events.

Mr. Steve Langley Director, Distribution Construction and Maintenance Orlando Utilities Commission said, "At OUC our emphasis has always been to leverage the power of technology in delivering better and faster services to our customers. Our investments in this direction have been yielding encouraging benefits to our customers, restoration teams and the organization as a whole".

Utilities which are yet to join the automation bandwagon have reported problems due to manual systems which include concerns about

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data integrity; complaints about large amounts of data entry; constraint of single-user access; inability to create historical records of event and lack of auditing and reporting features. All these and more impede providing of services in a timely manner and ultimately lead to customer dissatisfaction.

While a few companies have in-house automated their systems, they are faced with limitations like lack of on-going technical support, large amounts of data entry and delays/inabilities in timely development of new features, having to frequently switch between manual and automated processes, scalability issues or challenges which can typically be easy work for professional software development organizations.

User-friendliness is a key aspect identified for a successful automated system. When storm center personnel are called in during major outages, it is essential that they quickly understand and leverage the system. Majority of respondents felt that standardizing and automating the processes followed by various utilities will greatly enhance the efficiencies and reduce the cumbersomeness being currently experienced.

Says Jason Singer, Director at Macrosoft Inc, who spearheaded the survey "Rather than just gather and report historic information on occurrences, understand best practices and analyze the findings we have also tried to explore and evolve ways through which we can leverage technology to help utilities in their constant effort to improve efficiencies." He added, "Some of our innovations are already being used by large utility organizations and have shown impressive results."

In conclusion, the survey gathers important information on common best practices amongst utilities, highlights the need for standardization of mission critical processes and the impact/ importance of leveraging technology in managing restoration efforts aimed at delivering faster, better and reliable services to customers. ■

About the Author

John Kullmann is Vice President for Macrosoft Inc. a software company serving the utilities, telecom, and other industries. Macrosoft delivers sustained measurable results by utilizing state-of-the-art technologies to automate complex business processes.

Macrosoft has developed Resources on-Demand, an emergency resource management system for utility companies. Resources on-Demand is a fully web-enabled system replacing manual/Excel processes currently used at many storm centers to manage resource requests and track personnel movement during emergency outages.

A copy of the full report and information about the Resources on-Demand' can be found on Macrosoft web site: www.macrosoftinc.com or by contacting John Kullmann at jkullmann@macrosoftinc.com (973) 889-0500.

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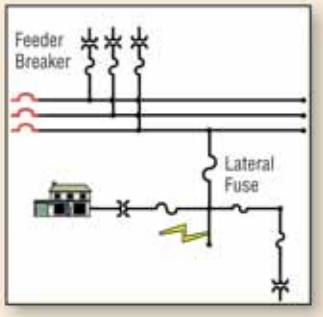

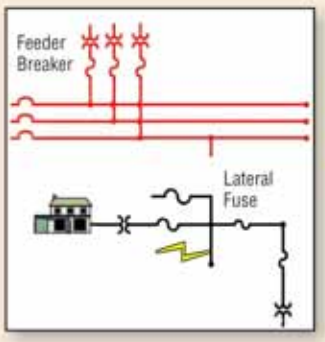

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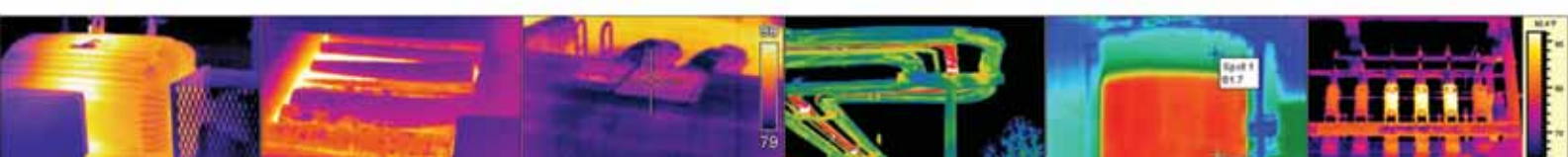

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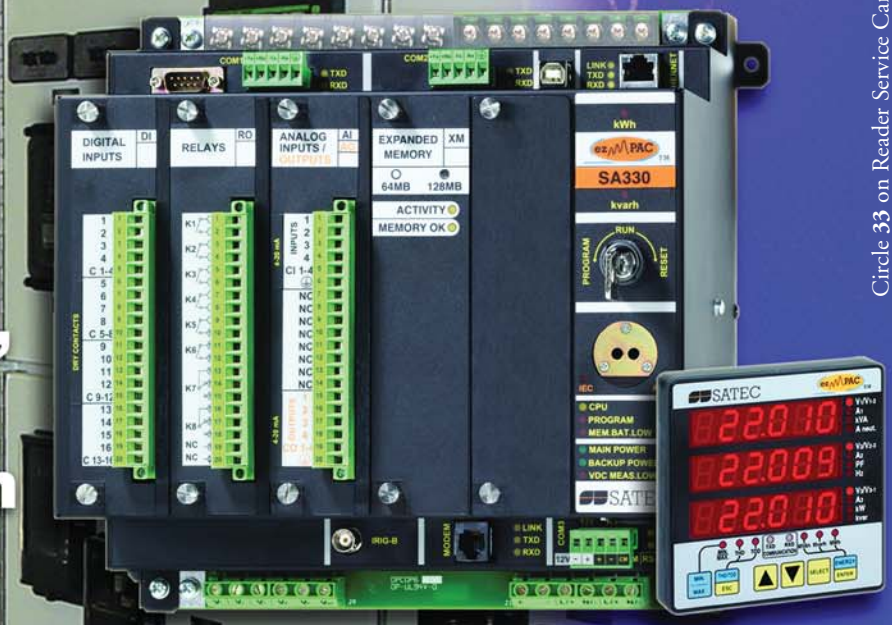
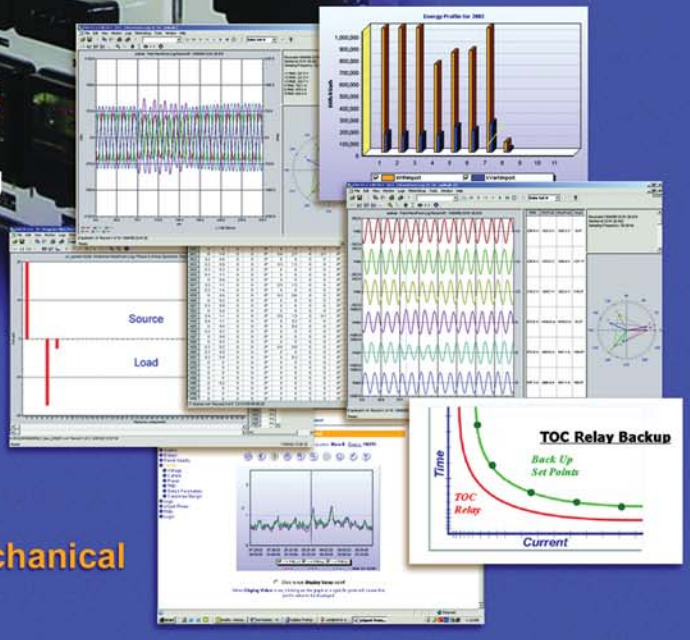
Power Intelligence Unit™

Automate by Adding to Existing Relays, Instead of Replacing Them



- **ONE ezPAC™ on each Feeder Circuit provides ALL the information needed for Automation:**
  - Accurate Measurements / Revenue Metering
  - Fault Analysis and Recording - Sequence of Events
  - Power Quality - Harmonics
  - Smart I/O
  - SCADA / e-mail / Web Access
- **Installation at a Fraction of the Money & Time**
- **Minimum Disruption of Operation - Low Investment Costs**
- **Enhancement / BackUp of Existing Electromechanical or New Relays**



SATEC

Powerful Solutions

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