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AFTER THE STORM

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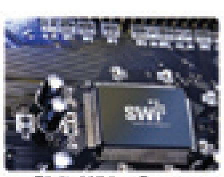

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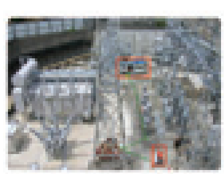

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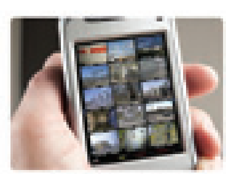

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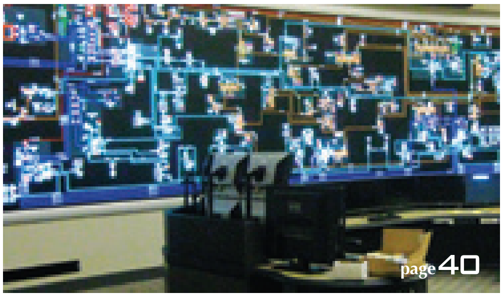

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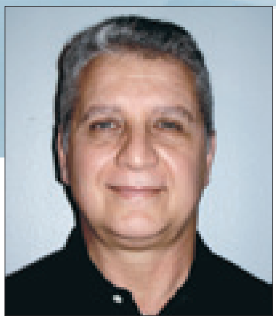
Michael A. Marullo, Editor in Chief



When the "saints" go marching in…

This month marks the fourth anniversary of the IEEE-Power & Energy Society (PES) Transmission & Distribution Conference that was (supposed to be) in New Orleans in 2006 – or at least that was the plan before Hurricane Katrina hit a few months before, causing the conference to be held in Dallas for an unprecedented twice in a row.

In 2004 the stage was all set for this landmark event to take place at the now infamous New Orleans Convention Center, and I remember looking forward to not having to travel to be able to attend a major conference for a change. But then, on August 29th a Katrina made landfall on the western edge of the Mississippi Gulf Coast – a scant 60 miles from here – and in a matter of less than 24 hours it changed everything. As we all know, there were lots of casualties, the most regrettable of which was, of course, the loss of life. No one who lost a loved one in Katrina or its terrible aftermath will ever forget that dark day in our history.

But there were other kinds of casualties too. The plans, hopes and dreams of families and institutions all across the Gulf Coast region were put on hold and in some cases, utterly destroyed; businesses and the jobs they provided vanished overnight without even a trace left behind; structures that were thought to be impervious to most any man-made threat or assault, quickly disappeared in a deadly confluence of wind and water. Suddenly, nature was our enemy, and we felt helpless to defend ourselves against it – and correctly so.

Anyone who has ever personally experienced a mega-disaster like a hurricane, an earthquake, a volcano or a flood knows exactly what I mean. It's a life-changing experience. You live your life differently from that point forward, and you eventually come to accept these foundational changes as what I've often referred to as The New Normal. Yet somehow we manage to adjust and adapt – we quietly reset ourselves and accept the altered state.

By contrast, when it comes to the fundamentals of our infrastructure – mainly air, water and electricity – we're far less likely to adapt. We're not inclined, nor are most of us able, to simply tell ourselves we can just "adjust and adapt" to using less water or less power for a prolonged stretch, much less for an indefinite period of time. But today, it is exactly that type of life-altering behavior that is probably in our future, if not already here. Using less of our natural resources and using what we absolutely must consume in a more efficient and environmentally responsible way is the implicit prescription for the future – whether we like it or not.

On that note, it's important to acknowledge that we are learning – albeit slowly – that those resources are not infinite (as we once tacitly assumed) and that there are things we can do to mitigate old "comfortable" behaviors without completely changing everything. But some discomfort is definitely in our future; perhaps a lot. Here are a few examples…

First of all, nobody I know wants transmission lines in their back yard (or their front or side yard, for that matter!), but just because we're finally making measurable progress toward a renewable energy portfolio, it surely does not obviate the need for transmission lines; actually, quite the contrary. Indeed, some recent studies evaluating the amount of sheer real estate – measured in acres or square miles for wind and roof-acres for solar – show that the process required to site these potentially huge contiguous usage areas is actually quite onerous, so much so that even some of the most prominent environmental groups are acknowledging the formidability of the task.

As it turns out, it might actually be easier – meaning faster and less costly and perhaps even less damaging to the environment – to site a fossil plant than to implement these renewables on a scale that would be significant in terms of overall energy production – bummer!

Another real hornet's nest is the controversy surrounding the integration of renewables into the grid, even if we assume that the transmission problems are solvable within a reasonable time frame and cost structure and, that the regulatory and environmental barriers will become more accommodating over time.

The diagrams I've seen of wind production look like a toddler scribbling on a piece of paper. I can't imagine how one would begin to model such an obtuse experiment in unpredictability, at least as it relates to the transient stability of the grid. Okay, storage is the simplistic answer, but now you've really said a mouthful. If someone has already figured that one out, please do tell…

In any case, as I said last month in this column, it's time for some serious thinking outside the box. I mentioned some of the latest advances in fuel cells and these things called nuclear batteries in that column that have the potential – remember I said potential; not panacea – for solving not only the distributed resources issue but also the insidious transmission proliferation problem. However, I cite this only as an example of the kind of innovative, "Hey, nobody told me this was impossible!" thinking and creativity that will almost certainly be needed to get us out of the mess we're in.

Meanwhile, every couple of years the IEEE-T&D Conference lands in a major metropolis, bringing with it the best and brightest ideas for addressing and solving the problems that vex and befuddle us on a daily basis. I'm not saying that the conference that will be underway as you read this holds all of the answers to our energy woes, or that this will be the year that we go all the way. But although it took the New Orleans Saints 42 years to get to the Super Bowl, they finally pulled it off! So when the "saints" go marching into the New Orleans Convention Center this year, almost anything is possible. – ***Ed.***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Industry News

California ISO Board Approves Fresno Area Grid Upgrades

Board Also Hears Briefing on 2010 Transmission Plan

Folsom, CA – The California Independent System Operator Corporation (California ISO) Board of Governors approved a series of transmission upgrades required for electric reliability in the Fresno area. The grid improvements will also allow more efficient use of the 1,200 megawatt Helms pumped storage power plant located in the foothills east of Fresno.

The Fresno transmission upgrades approved on March 26 include six projects to replace transmission conductors with modern materials that can carry more electricity and a variety of other significant, but invisible, changes to the existing grid in the area. The total estimated cost of these projects is $127.5 million. A full description of the projects is included in the **documents** presented to the Board.

“These upgrades help meet the electrical demand in the Fresno area and optimize the use of the Helms pumped storage facility,” said ISO Vice President of Markets and Infrastructure Development Keith Casey.

The Helms power plant provides important versatility because it can pump water uphill at night when electricity is plentiful and generate power the following afternoon when the demand is high.

“The current conditions in Fresno allow only one of the three pumps at Helms to operate overnight during the summer season and this does not meet the expected local area need,” said Casey. “The projects our Board approved today (March 26) will solve that problem over a ten year planning horizon and allow use of two of the three Helms pumps during the critical summer off-peak period.”

In the longer-term, Casey notes additional transmission enhancements may be warranted for the Fresno area to further improve utilization of the Helms pumped storage facility, to help integrate renewable resources and potentially to help move wind power from the Tehachapi region into Northern California. “These options will be evaluated as part of our ongoing comprehensive transmission planning efforts for meeting a 33% renewable portfolio standard in 2020,” said Casey.

California ISO planning staff also briefed the Board of Governors on the 2010 Transmission Plan. The plan, developed with stakeholders throughout 2009 and into 2010, lists 29 projects with a total value of $573 million that the ISO deemed necessary to meet North American Electric Reliability Corporation (NERC) reliability standards. The ISO Board already approved projects in the plan valued at more than $50 million as required by the ISO planning process. Projects valued at less than that threshold do not require specific Board approval.

“The 2010 plan is a road map to continued reliability for the ISO grid,” said Casey. “Every year, we refine our transmission plan and roll new information into it. This 2010 effort is a comprehensive approach to making sure the grid we have today continues to evolve into the grid we will need a decade from now.”

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AMSC and LS Cable Expand Superconductor Power Cable Strategic Alliance

Devens & Seoul, Korea – American Superconductor Corporation (NASDAQ: AMSC), a global power technologies company, and LS Cable Ltd. (LS Cable), the third largest power cable manufacturer in the world, announced on March 24 that they have expanded their superconductor power cable strategic business alliance. Under the new agreement, LS Cable and AMSC will work collaboratively to deploy more than 50 kilometers (km) (31 miles) of superconductor power cables in commercial power grids over the next five years. The original alliance, **established in September 2009**, called for the deployment of a minimum of 10 km (6.2 miles) of superconductor power cables during that same period.

The agreement was reached at a meeting in Devens, Massachusetts attended by LS Cable President and Chief Executive

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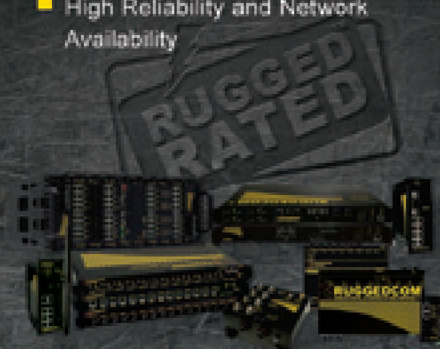

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Industry NEWS

Officer Jongho Son and AMSC President and Chief Operating Officer Dan McGahn. Korea Electric Power Corporation (KEPCO) Vice President J.W. Chang was present to witness the signing. KEPCO is South Korea's only power distributor. The strategic alliance focuses on the full spectrum of superconductor cable projects, including distribution and transmission voltages as well as alternating current (AC) and direct current (DC) systems. Superconductor power cable systems manufactured by LS Cable will utilize AMSC's proprietary second generation (2G) high temperature superconductor (HTS) wire, branded as 344 superconductors.

"LS Cable is focused on developing and implementing world-class technologies to both meet the evolving energy needs of today's economy and provide the infrastructure necessary to support tomorrow's growth," said LS Cable's Jongho Son. "Superconductor cables offer unique power density, efficiency and security advantages compared to conventional power cables and will play a key role in providing the necessary backbone to support the Smart Grid in Korea and locations around the world. We are pleased to expand this important strategic alliance with AMSC."

Power cables made with AMSC's HTS wire can conduct up to 10 times the amount of power of conventional cables, which are made with copper wire. They can be placed strategically in the power grid to draw flow from overtaxed conventional cables or overhead lines to mitigate grid congestion experienced in urban centers. They also automatically suppress dangerous power surges to create resilient, 'self-healing' Smart Grids that can survive attacks and natural disasters, making them an ideal modernization tool for metropolitan power grids.

"LS Cable, which is one of the world's leading and most innovative power cable manufacturing firms, continues to demonstrate its commitment to advancing the commercialization of superconductor cables as a best-in-class solution to meeting the growing and evolving power demands of the 21st Century," said Dan McGahn of AMSC. "Our companies share this common vision and see tremendous opportunities for commercial deployments of transmission and distribution superconductor cable systems around the world."

In April 2009, AMSC received its first commercial order from LS Cable for approximately 80,000 meters (50 miles) of its 344 superconductors to manufacture a 22.9 kV cable system that will be installed in KEPCO's Icheon substation near the city of Seoul later in 2010. Capable of carrying 50 megawatts of power, the cable system will be nearly a half mile in length, making it the world's longest distribution-voltage superconductor cable system.

J.W. Chang of KEPCO said, "KEPCO has embarked on an ambitious plan to make Korea's power grid the world's cleanest and most efficient. We are utilizing various technologies to realize our vision for a 'Smart Green Utopia.' Chief among these is superconductor power cables. We look forward to energizing the first of these cables in our power grid later this year and to beginning our commercial adoption phase in 2012 with the assistance of LS Cable and AMSC."

Korea Implementing the World's Smartest Grid

In 2009, South Korea's government announced plans to be the first country to convert its entire electricity network to Smart Grid technologies. The project is estimated to cost approximately US$25 billion.

As part of its "KEPCO2020" Mid-to-Long-Term Strategic Management plan, KEPCO has identified the Smart Grid as the utility's next growth engine and is concentrating its research and development on eight "Green Technologies," including High Voltage Direct Current (HVDC) and superconductor technologies. These technologies will be used to implement KEPCO's "Smart Green Utopia" in Korea by 2020. KEPCO also is looking to expand its Smart Grid business to foreign markets. In 2009, the South Korean government announced plans to boost the country's domestic industries to capture 30 percent of the global Smart Grid market.

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PJM Reports New Carbon Dioxide Emissions Data

New report will be available annually

Valley Forge – A new report from PJM Interconnection can be used to estimate carbon dioxide reductions from demand response, energy efficiency measures and increases in emission-free generation.

The report shows the average amount of CO_2 emitted for marginal units – generating units that are the last to be brought on-line and set the price for energy for that five-minute increment – during both peak and off-peak periods.

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Industry NEWS

Any reductions in power use or increase in emission-free generation would reduce production and CO_2 emissions by marginal generation units.

The tables and charts illustrating these numbers are available at *http://www.pjm.com/documents/~/media/documents/reports/co2-emissions-report.ashx*. The information was presented to the PJM membership on March 25 as part of a general report on the PJM Markets and will be updated annually.

"Now when our members and others want to evaluate how much CO_2 was produced year to year, month to month, peak or off-peak, they have a source that provides the latest actual information, rather than having to draw from several sources to estimate," said Andrew L. Ott, senior vice president, Markets. "We are happy to extend our role as an independent information provider to aggregate regional carbon emissions and provide insight on emission rate trends within our region."

As part of PJM's role in assuring the reliability of the regional high voltage transmission system and the integrity of the wholesale power market, Ott said, is providing accurate and transparent information to guide decisions. PJM provides this information as a service to its stakeholders.

The report shows PJM's analysis of the CO_2 emissions rate information for marginal units for each five minute interval from January 2005 through December 2009. The five-minute marginal data was aggregated into hourly blocks and then sorted into on-peak and off-peak time periods and ultimately averaged for each month. Peak periods are all non-holiday weekdays from 7 a.m. until 11 p.m. and off-peak periods are all other hours. Annual statistics are also provided.

Marginal units would include any units brought on line to support the real-time demand for electricity not already provided for by existing contracts. Generating units may include units fueled by fossil fuels, natural gas, nuclear and other sources.

The PJM Emission Report can be used to estimate CO_2 reductions as a result of certain efforts within the PJM region such as demand response and energy efficiency measures. The report can also be used to estimate the impact of increases in emission-free generation such as wind farm operations and upgrades to nuclear generation facilities. This report also provides an overview of the general trends of emission rates within the PJM region.

PJM Interconnection ensures the reliability of the high-voltage electric power system serving 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, which includes 6,038 substations and 56,350 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. Visit PJM at *www.pjm.com*.

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GUEST EDITORIAL

The "Human Smart Grid"
A Look into the Window of Smart Grid Evolution

By John D. McDonald, GM-Global T&D Marketing, GE Energy (Atlanta, Georgia USA)

With every passing moment, technology evolves, events take place, and a new slice of history is made. We can easily look back at the history made yesterday to understand what has happened and why, but it's far more difficult to look into tomorrow's window to anticipate what will soon become history. Looking into the window of smart grid evolution, what developments can we expect to see on the road ahead?

Certainly, utilities will continue to develop and deploy newer and more advanced smart grid technologies over the next three to five years. And as they do, will the average consumer begin to see sweeping changes, such as significantly lower electricity prices, fewer and less frequent blackouts, and more efficient delivery of power to their homes and businesses? Or, will they simply see "business as usual" in the electrical industry?

Far from Business as Usual

Though smart grid evolution will be far from "business as usual" over the next several years, the biggest near-term impact will be on the electrical grid itself, as utilities both large and small further the expansion and implementation of advanced smart grid technologies. However, additional developments occurring in parallel with grid expansion, such as Demand Response programs, will have an effect on the average consumer, though these effects will probably be felt more in the mid-term rather than in the near-term.

Once these already proven technologies are in place, the onus on utilities will need to shift to gaining consumer understanding, and subsequently consumer acceptance, by establishing comprehensive, two-way educational and informational programs to move successfully forward with larger scale deployments and consumer-empowered Demand Response programs. When this occurs, it will signal the emergence of the "human smart grid."

Education, Acceptance – the Keys to Understanding

Consumer education and acceptance will be essential keys to unlocking the sweeping economic and societal benefits that a nationwide smart grid can deliver to an energy-hungry nation. With well thought-out and implemented education and communication programs, utilities can plant the seeds that will help consumers comprehend the actual workings of a smart grid, how it enables economic vitality and energy independence, and how it keeps more of their own money in their own bank accounts. And consumers will need to accept and embrace the concept that realizing the benefits of a smart grid is going to require an open, collaborative effort on their part—and that their participation is as much an integral part as any piece of "smart" technology.

GUEST EDITORIAL

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As utilities endeavor to educate customers, they'll discover that they will also be educating themselves; educating themselves about what their customers want, what their customers need, what their customers demand, and what the nation must ultimately achieve to obtain energy independence. Operating like a "human smart grid," two-way communication between utilities and consumers will in itself demonstrate the effectiveness of the two-way communication that is the hallmark of the electrical smart grid.

Using customer surveys, segmentation analysis, voluntary participation programs, informational notices enclosed with utility bills, and town-hall format educational sessions, utilities and consumers can learn from one another how to better formulate future deployment plans, more easily identify and focus on areas requiring improvement, and finely tune pilot plans already in place to facilitate larger, more effective smart grid deployment. All this, enabled by the simple concept of creating and sustaining a human communication network.

Linking Regulators to the Human Grid

While educative dialogue between utilities and consumers progresses, regulators at both the state and federal levels will need to become "linked in" to the discussion to ensure that the proper regulatory backing is put in place to move smart grid evolution in the right direction. Regulatory support, such as a move away from the need to sell more electricity to increase revenues, will be required to ensure that utilities are compensated for conservation programs that meet electrical demand while selling less electricity.

With economic stimulus funds becoming more abundant and more available in the coming year, legislators will also need to have their ears to the ground as they enact stimulus-backed smart grid policies that are conceived with an educated, holistic understanding of the energy needs not only of today's consumers and providers, but with the added focus of meeting the nation's energy needs of tomorrow.

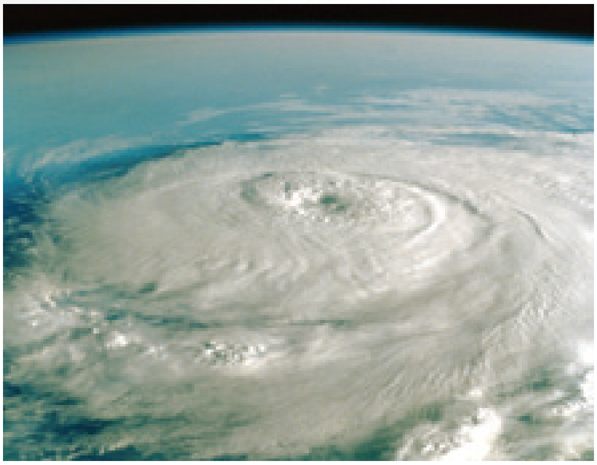
Consumer Involvement – the Missing Link

As smart grid evolves over the next three to five years, consumers will probably not see sweeping economic differences in their everyday lives. But during that time, their voice can serve as a guide for utilities and regulators in steering smart grid to greater success, and perhaps even accelerate the timetable during the process. By getting involved in two-way educational programs, actively participating in available pilot programs, and embracing smart grid as the long-term solution to our nation's energy and economic challenges, consumers can serve as the vital missing link in the "human smart grid." The window of opportunity is open to make tomorrow's history... today. ■

About the Author

John D. McDonald, P.E., is General Manager, Marketing for GE Energy T&D. In his 36 years of experience in the electric utility industry, John has developed power application software for both Supervisory Control and Data Acquisition/Energy Management and SCADA/Distribution Management System applications, developed distribution automation and load management systems, managed SCADA/EMS and SCADA/DMS projects, and assisted Intelligent Electronic Device (IED) suppliers in the automation of their IEDs.

John received his BSEE and MSEE (Power Engineering) degrees from Purdue University, and an M.B.A. (Finance) degree from the University of California-Berkeley. John is a member of Eta Kappa Nu (Electrical Engineering Honorary) and Tau Beta Pi (Engineering Honorary), is a Fellow of IEEE, and was awarded the IEEE Millennium Medal in 2000, the IEEE PES Excellence in Power Distribution Engineering Award in 2002, the IEEE PES Substations Committee Distinguished Service Award in 2003 and the 2009 Outstanding Electrical and Computer Engineer Award from Purdue University. He is also a member of DOE's Smart Grid Electricity Advisory Committee (EAC), is a member of NEMA's Smart Grid Council, and is on the Board of Directors of the GridWise Alliance.



Smart Grid vs. New Normal:
Parallels in Post-Katrina New Orleans

By Michael A. Marullo (and millions of Gulf Coast inhabitants)

Ask anyone who has ever been to New Orleans what it's like, and they'll tell you it's a pretty unique place to live and work. And despite the "suggestions" directed our way from a few politicians, commentators and otherwise concerned citizens following Hurricane Katrina to "shut the city down and move it to higher ground" (Montana maybe?), it's still very much here – and always will be.

Four and a half years after Katrina we're still right here in southeast Louisiana; still perched at the mouth of the mighty Mississippi River; and still overlooking the (occasionally treacherous) Gulf of Mexico. But despite having survived the worst natural disaster in the history of our country, I have to stop short of saying we're back to normal – that would imply that nothing has changed. The fact is, a whole lot has changed – mostly for the better, but some for the worse – and neither is really a big surprise. We're just learning to adapt to the New Normal.

Thinking back on the past 4½ years that have passed since Katrina made landfall on August 29, 2005, I've had a lot of time to think and reflect on the transition from a pre- to post-Katrina environment – the post-storm period being something I've previously referred to as our *New Normal*. Katrina caused virtually everyone in the Gulf Coast region to adjust and adapt to a life and a lifestyle that is very different from the way things used to be. And although we've tried really hard to put Humpty Dumpty back together again precisely as he once was, we've learned that the cracks still show and that all the "glue" in the world will never quite fill all those cracks correctly or completely.

By contrast, the grid has remained relatively unchanged. But let me be very clear that by unchanged, I mean only from a grid topology perspective. In no way am I suggesting that the grid hasn't changed or advanced in other ways. On the contrary, the grid has evolved significantly over the past century – mostly during the past 50 years – into a network that employs intelligent architecture at virtually every level and that is populated with roughly a gazillion (give or take a few) intelligent systems, subsystems and devices.

The more I think about it, the more I see emerging parallels between the post-Katrina challenges of our region and those of grid transformation. So, I want to take this opportunity to share some real-world experiences that I hope will offer useful insights into lessons learned in storm recovery and that may be at least partly transferrable to facing and overcoming the challenges of what I'll collectively refer to as Smart Grid Transformation.

Don't Change That!

To begin with, there are some stark parallels between New Orleans culture and that of the electric utility industry when it comes to change.

Neither likes change much, and if anything, New Orleans is far more stalwart when it comes to resisting it than it is to embracing it. I doubt that anyone would argue that it's a whole lot different for electric utilities. But that isn't necessarily a bad thing. At least to some degree, it has a lot to do with actually liking the way things are and not wanting to fix things that aren't broken, purely for the sake of change – the latter sometimes called progress or modernization even when those labels aren't entirely backed by hard evidence. But let's not debate the pros and cons of change; we all know that there are always two sides to it – and both sides usually think they're right!

Instead, let us consider one of the biggest reasons why many of the things that really need to change don't – money! More often than not, we can't change what we can't pay for. Change is hard enough even under the best of circumstances, but lack of funding is usually the ultimate deal buster.

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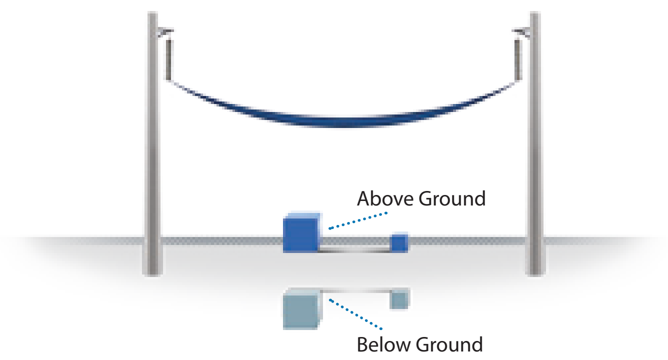

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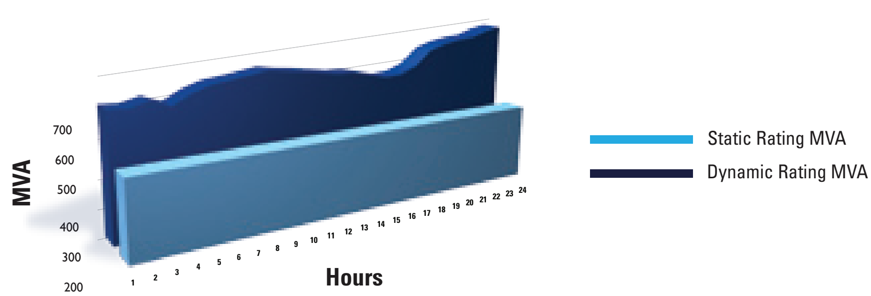

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ALCAN

Smart Grid vs. New Normal: Parallels in Post-Katrina New Orleans

By Michael A. Marullo (and millions of Gulf Coast inhabitants)

Take, for example, the U.S. Environmental Protection Agency program that appropriated some $150 million in the aftermath of the 9-11 attacks for water and wastewater utilities to undergo a security vulnerability assessment. Within a fairly short period of time they had spent the money and completed lots of audits, but when the money ran out, practically nothing was done to remediate the problems identified by the audits.

Why? Well it wasn't that the utilities didn't want to fix their problems; many of them were genuinely alarmed by the vulnerabilities the audits had identified. The main impediment was, quite simply, that no money was budgeted or otherwise available to be able to follow through with the recommended fixes. Yet despite several attempts to make that follow-through a legislated or regulatory requirement, utilities usually don't respond well to anything they consider an unfunded mandate – which this clearly was – so those attempts failed.

Lesson #1: Deferred Maintenance

But let's move on to the reason why many if not most of the problems in cities like New Orleans as well as utilities find themselves up the creek without a checkbook when it comes to the well being of their infrastructure: Deferred Maintenance. For decades, we've been "deferring maintenance" and thinking we were putting off the inevitable infrastructure failures we're beginning to see with regard to roads, bridges, railroads, water pipes, sewer lines, telecom circuits and yes – power lines – as well as the surrounding support infrastructure so desperately needed to maintain their viability.

Perhaps nowhere in recent history has there been a more glaring example of the consequences of (habitually) deferring maintenance than in post-Katrina New Orleans after the storm waters from failed levees finally receded. Once "Lake Katrina" was drained and the ground began to sink, crack and crater, our water distribution and sewer systems turned into a huge sprinkler system, at one point leaking an estimated 90 million gallons a day through cracked or broken pipes and connections.

Two and a half years later, New Orleans Sewerage & Water Board officials estimated repairs at more than $800 million – the federal funding for which had not yet been approved – plus, the utility was already more than $500 million in debt at that point. But that doesn't tell the whole story. By the utility's own estimates, those pipes were already leaking an estimated 60 million gallons of fresh water each day – BEFORE the storm. It seems that our already crumbling, century-old cast iron pipes were already at the end of their useful life, and the floodwaters were truly the final straw. (Ditto for much of the gas distribution system, sewer lines, roads, and other parts of our already fragile infrastructure.)

So why did we let it get so bad, one might ask? The answer is simple: No money, honey. But make no mistake; this is far from being a just a New Orleans problem, a Gulf Coast problem or even a regional problem. Virtually every other major metro area in the nation – possibly excepting some of the newer communities in places like Arizona, Colorado, Florida and Nevada – suffer from various forms of the same chronic lack of funding for maintenance and repairs. And even some of those younger cities and towns are already seeing the same kinds of problems in their K-12 schools, college campuses, hospitals and other institutions where deferred maintenance is estimated to be well into the tens of billions of dollars.

The good news – relatively speaking – is that for the most part, the grid is far better shape, since we really didn't start neglecting it until fairly recently! Indeed, under a tightly regulated environment for most of its existence, the dual goals of safety and reliability helped to ensure that the grid was in top working order for decades. It wasn't really until about 20-25 years ago that spending on infrastructure took a big hit as utilities got mixed signals about whether or not their investments would wind up being stranded assets – the very thought of which is anathema to most utilities.

Yet that doesn't change the fact that much of the grid's physical plant (i.e., not just the wires) is approaching the limits of its useful life – generally deemed to be 35-50 years for workhorse grid components such as switches, transformers, regulators and breakers. And, although the grid is nowhere near as bad off as the New Orleans water distribution system, there's a lesson to be learned about how neglect and failure to reinvest in that which we have come to rely on in our daily lives can be immensely disruptive, not to mention expensive to fix under duress.

Lesson #2: Funds Flow

Fortunately, the Federal Emergency Management Agency (FEMA) and the U.S. Congress stepped in and stepped up to help fund the storm-related repairs, which were just recently estimated to be in excess of $80 billion – which brings us to the second parallel: Funds Flow. Anyone who follows the news at all knows that we're in the midst of the biggest economic stimulus in our nation's history, that being the American Recovery and Reinvestment Act (ARRA), commonly known as the Stimulus Bill.

And as most of you reading this probably also know, approximately $3.4 billion of the $700 billion+ being injected into the U.S. economy is targeted for the energy industry. These are both very big numbers, and I, for one, have no doubt that given sufficient time, these funds will have a huge impact on the economy and spur both jobs and economic growth.

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Quite frankly, I don't see how it couldn't, even though it is inevitable that there will be the usual inefficiencies and waste that invariably comes along with most large government programs. But again, let's not get into the political debate – I'm all for whatever works, but at the same time I'm concerned about that phrase I used in the previous paragraph: "…given sufficient time." Why? Because when it comes to actually getting the folding green into our hands, it turns out that "sufficient time" can be a really long time. Here, Katrina offers us another teaching moment…

Towards the end of 2005, after the initial wave of post-Katrina chaos finally cleared a bit, and the government set about mobilizing its money machine (Congress), those of us here in the devastation region were (and will always be) truly grateful for the economic assistance we have received – and continue to receive – from a generous populace across the country and around the world. Of course, the standout in the crowd was the U.S. government, which appropriated billions of dollars for disaster recovery in the months and years following the storm.

But the nasty little secret here is that "appropriation" is not the same thing as "delivery" – nowhere near. In fact, it was years before any substantive portion of the monies that were initially announced finally reached the affected areas. And then, of course, state and local bureaucracies did their part to further retard the flow of funds to a point where many began to think they would never actually see a dime. Fortunately, that was not the case, but the amount of time it has taken to weave its way to the intended destinations has been long and agonizing to say the least, despite the scope and urgency of the need, taking years to accomplish what most thought would be a matter of weeks or months.

Now that the Stimulus funds have been appropriated and awarded in the energy sector, we are once again in that "wait and see" mode. Only recently has the first utility actually received the initial chunk of cash to execute its plans. But along with the check came a mountain of paper – forms and reports to be filled out, reportedly within 30 days after receipt, with another batch of paperwork expected to follow soon thereafter. This brings me to my third and final point…

Lesson #3: The Paper Chase

Following Katrina, the federal government set up several field offices in and around New Orleans to assist businesses and individuals applying for SBA (Small Business Administration) loans. Now I already knew from previous experience as a longtime small business owner myself, that navigating the SBA was no easy path; but I was willing to give it a chance. The first clue that this might be a quagmire is that scores of companies exist – and do quite well – helping small business owners to fill out SBA loan applications in exchange for a fee. Unfortunately, I was not to be disappointed that this would be an arduous process, at best.

Although I don't personally know of a single person or business that actually received an SBA loan, I'm sure there must be some. But what I do know is that there are many who were either turned down flat, repeatedly told to re-apply after being informed that their application had been lost – often multiple times – or simply ignored altogether. Today, most people here agree that the SBA loan program was at best a bureaucratic nightmare, and at worst, a dismal failure.

Moral of the Story

The moral of this story is not at all that there is no hope of transforming the grid into the dynamic, 2-way power network it needs to be to take us through the next 50-100 years. In fact, there is no doubt in my mind that we can – and will – accomplish that task and a lot more. But we have to be realistic, and we have to change our ways if we're going to keep from making the same mistakes all over again.

First and foremost, that means taking care of our infrastructure and investing incrementally to avoid a meltdown and the need for another rescue at some point. Second, it means not relying on instant gratification, at least not financially. We've learned that the wheels of progress turn slowly – and even slower if they have to roll through bureaucratic entities to see the light of day. And finally, let's not wait for the other shoe to fall. Be proactive in pursuing goals and objectives, and don't wait for the gravy train. Hope for the best, but be prepared for whatever challenges might lie between where you are and where you need to be.

Today, New Orleans is in a far better place than on the morning of August 30^{th}, 2005 – the day after Katrina, and each day it gets a little bit better. By working together, we have moved mountains (figuratively speaking; we still don't have any here, and Monkey Hill at the Audubon Zoo is still the highest point in the city!). By coming together at this historic IEEE Conference, we move another step closer to a smarter grid and a brighter future.

So welcome to New Orleans… and the New Normal.

LightsOn

AFTER THE STORM
Forged by Industry Change and Nature's Fury, Entergy Shapes Its Course

By Mark Mc Culla and
Paul Cassingham
Entergy Services, Inc.
New Orleans,
Louisiana USA

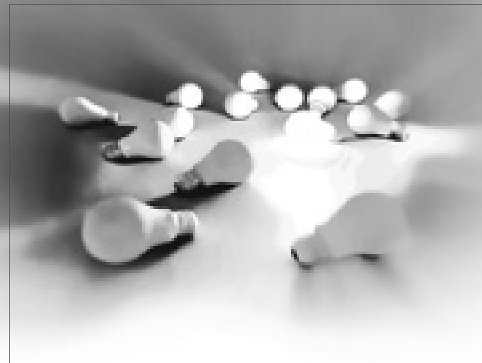
Tested by nature and driven by industry change, Entergy Corporation has emerged as one of the leading utility companies in the world. Over the last decade, Entergy reshaped itself from a company with operations scattered around the world to a world-class U.S. utility focused on meeting the needs of its customers while creating value for shareholders. Entergy is now one of the largest electric utilities in the country with 2.7 million retail customers and more than $10 billion in annual revenues. The transformation hasn't always been easy. During five years of that decade of change, Entergy's utility companies battled nature's fiercest forces... and won.

The devastation from hurricanes Katrina, Rita, Gustav and Ike affected many of the company's customers, and the damage done by the storms won't be forgotten by any of the utility company employees who live and work in Arkansas, Louisiana, Mississippi or Texas. Tackling major disasters takes patience and persistence and requires constant adjustments to changing circumstances, the same skill sets needed to navigate the turbulent operating and regulatory environments of today's electric power industry.

But the struggle to overcome the destruction produced by these catastrophic events paid long-term dividends for Entergy. The company has used the lessons learned preparing for and rebuilding after each event to shape strategies that reach beyond disaster preparation and recovery disciplines. Indeed, preparing for and responding to the storms did more than sharpen the company's disaster recovery skills. The logistical planning and coordination involved are now proving their value under routine business conditions.

Hurricane Katrina devastated Entergy's transmission and distribution networks as evident in this photo in Plaquemines Parish, La. taken soon after the storm had passed through. Lessons learned from that storm and three others helped shape the company's course over the past five years.

LightsOn



Turbulent Times; Economic Storms

Over the last decade the electric power industry has changed in major ways. Wholesale power deregulation, national energy legislation, more stringent reliability standards, more demanding operating economics, fuel cost volatility and technology have been the chief change drivers.

Regulatory, legislative and economic forces can profoundly change the wholesale and retail electric power marketplaces, how customers use energy and how industry professionals do their jobs. These changes call for the same urgency of response that customers, the media and government officials call for in the wake of disaster.

Meanwhile, no one in the electric power industry has escaped the impact of national and global economic conditions. Demand in 2009 fell 4 percent below expected levels, in part because of demand response and energy efficiency. However, economic factors drove the largest portion of last year's demand decline.

The North American Electric Reliability Corporation's forecast last October brought this home when NERC cut its estimate for annual demand growth in North America to below 1.5 percent. That projected demand growth was down from an earlier projection of almost two percent. NERC's revised estimate – if it holds true – means demand will reach approximately 4,700 GWh in 2011 instead of this year, as had been previously predicted[1].

Growth Without Demand Growth

Historically, reduced demand meant less construction of bulk power facilities, but this time that may not be the case. NERC has signaled that more than 11,000 miles of new transmission lines will be needed by 2013, double the average number of transmission miles constructed during the last 20 years. Policymakers believe that nearly 230,000 megawatts of new wind and solar generation would require that much new transmission capacity.

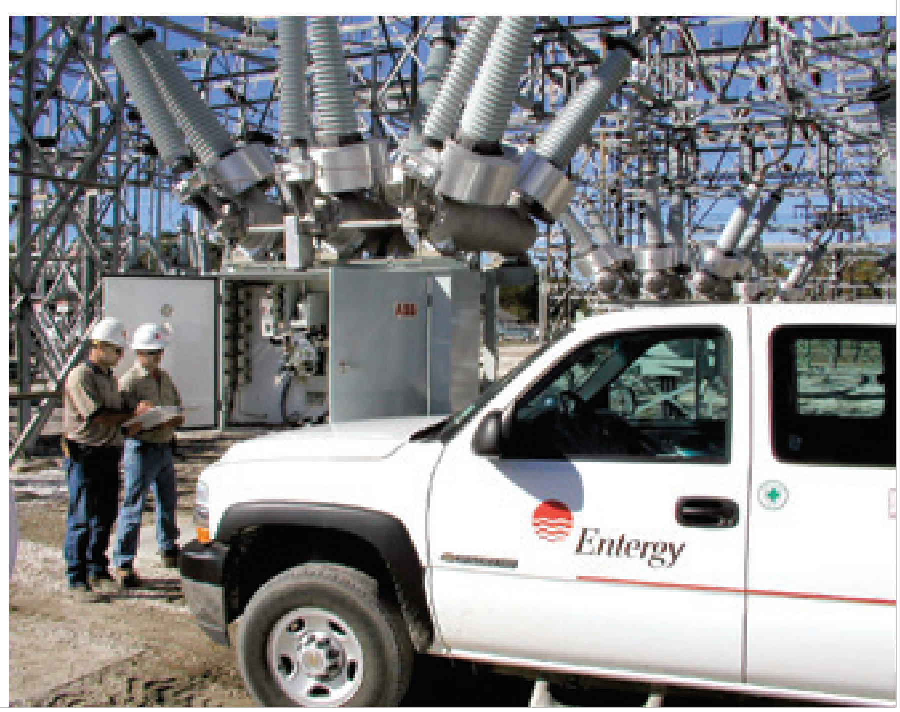
Complicating the issue is that wind and solar technologies cost more than conventional generation. Broad acceptance of the idea of greener energy depends on economic forces. At press time, Louisiana's retail regulators were studying a non-mandatory renewable portfolio standard. The economic status of the commission's constituents is a consideration. During times of tight household budgets, the higher price that green energy often demands can outweigh consumer enthusiasm. Moreover, the locations of that wind and solar generation in the southwest and Midwest will require new transmission in those regions to overcome existing constraints so that renewable power can be shipped to other regions.

Technically this is feasible. However, the unanswered questions are: What will it take to make that massive investment a sound business decision? Who will pay for and benefit from the new transmission capacity? How will siting and permitting be handled?

Rules of the Road

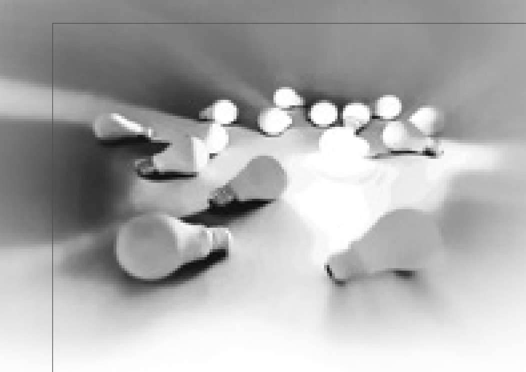
The answers to those questions will ultimately come from regulators. The Federal Energy Regulatory Commission has made progress toward more clarity on evolving reliability standards. For example, the 564 reliability standard compliance cases brought forward by NERC last December were the start of the agency's effort to give stakeholders more transparency on compliance issues. At that time, a FERC official said the agency would provide informal guidance with its future decisions rather than develop compliance models for industry to follow.

It appears that programs by FERC's Office of Enforcement could supplement that informal guidance, which will be used to avoid giving parties an overly narrow sense of the compliance standards they must follow. The official added that the effort would address concerns about clarity on the standards.



Entergy employees at a recently built new substation in Louisiana during final check out prior to energizing. Entergy's operating companies have made significant investments in infrastructure in the wake of four major hurricanes.

[1] NERC Nov. 2009 Industry Assessment Report



Clearing those backlog cases has given the industry greater confidence that its programs are working and also provides guidance on areas where there may be room for improvement. However, the need remains for a clearly defined, specific set of standards that apply across the industry.

Who Pays… When and How?

As the industry evolves and adapts in the context of energy policy that calls for more demanding environmental and efficiency metrics, a central challenge is to educate the public about what it takes to bring this vital commodity into homes, schools and businesses reliably and affordably. It will fall on the industry to fulfill the promises of changing national energy policy, the success of which hinges heavily on transmission.

Like other utilities, over recent years Entergy has made large investments in its distribution and transmission infrastructure. But the regulatory lag between when utilities make large capital expenditures and when they recover those investments through rates continues. Today, the new industry environment demands new ways to address timely cost recovery. Entergy's post-storm experiences and initiatives offer an insight into this pervasive issue.

In the aftermath of the four major storms of 2005 and 2008, Entergy successfully navigated the bankruptcy of its New Orleans operating company and in cooperation with state and federal officials, negotiated storm cost recovery strategies that addressed recovery of the investments and reduced the burden of those costs on customers.

Now the entire industry faces a similar challenge – how to pay for an expanded, upgraded transmission grid that will work efficiently in a new era of energy policy without financially overburdening the very customers it is meant to serve. The need for an expanded, transmission grid is an accepted fact. Some in government and industry suggest that the solution to the cost of modernizing and maintaining the nation's transmission grid is to socialize those costs, meaning all users should pay equal amounts for electricity delivery and for the expanded, updated grid technology.

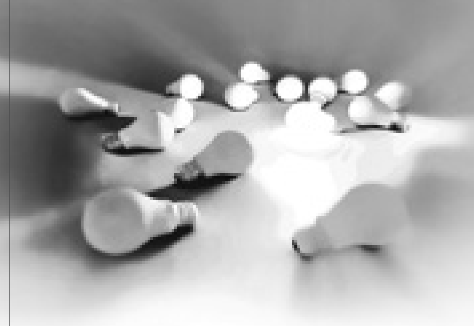
As they did in developing equitable storm cost recovery mechanisms across Entergy's foot print, state regulators – in concert with FERC and the Department of Energy – will play key roles in defining the policies and processes whereby regulated utilities can recover the investments made to bring these expensive, large transmission grid expansions and improvements into service. And the outcome of regulatory and public debate on those issues will shape the electric power industry for decades.

Bigger, Smarter, Friendlier Too

Entergy and its customers manage power flows across 15,500 miles of high voltage transmission lines, 1,800 substations spanning four states and hundreds of thousands of miles of distribution lines. But whether the person managing energy flow is a NERC-certified trained professional at a control center, or a homeowner looking over a monthly bill, they would both benefit by knowing what's happening with the energy in the system. Both would want to know where power should be sent and when, what it costs and how efficiently and smartly it is used.

LightsOn

LightsOn



Actively managing power flows across the hundreds of thousands of miles of the Eastern Interconnection's transmission grid offers the same challenges and holds the same potential for smarter, more efficient, more environmentally neutral use of energy, but on a vastly larger scale.

Although electromechanical devices are still prevalent in the control systems of the grid, they are quickly being replaced by increasingly more intelligent, solid-state electronics. Computers and energy management software are now the brains and nerve network of today's transmission systems. The bulk power transportation network is fast becoming a cyber network, and that presents both opportunities and challenges. Indeed, society's need for power, coupled with the potential risks inherent to this cyber environment, are why NERC and members of Congress have made the security of utilities' critical physical assets and cyber assets a major focus area.

Smarter and Tougher

The smart grid label so prevalent today may be a misnomer. The modern large area transmission systems are anything but dumb. A vast amount of advanced technology is already in place and has proven its worth across the playing field, saving both time and money while also improving safety, reliability and security.

During and after Hurricane Gustav, remote, real-time sensing devices at key locations across Entergy's system did front line duty. These devices, called phasor measurement units (PMUs), provided an instantaneous flow of data to control centers, and the data they supplied helped keep the lights on in New Orleans and Baton Rouge. These PMUs gathered, stored and transmitted data in real time that let Entergy and other utilities keep transmission and distribution systems operating reliably during the critical early phases of restoration.

By having the PMUs' Global Positioning Systems time-synchronized with frequency measurements at 30 samples-per-second, Entergy had an advantage not possible with supervisory control and data acquisition input. Since SCADA data is non-GPS synchronized and collected only once every two to four seconds, it could never have captured the event with the same level of quality, as did the phasor units.

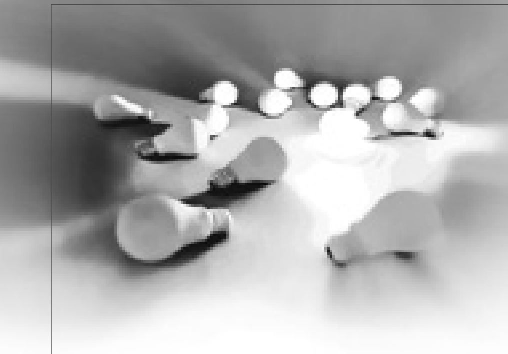
Phasors really proved their worth in the hours after Hurricane Gustav slammed into the Louisiana coast, separating the Amite-South transmission grid and three fossil units from the rest of the system and causing 850,000 outages – the second most in Entergy's history and creating what came to be known as an island.

When operators compared data from Entergy's phasors at its Waterford nuclear plant in Louisiana and its Mabelvale, Arkansas, location, they saw frequency oscillations indicating that the grid feeding the New Orleans area had become isolated from the rest of the system, creating an island of electricity surrounded by Gustav's destruction. The islanded portion of the system was resynchronized to the grid the day after Gustav, an unprecedented feat. A second connection to the grid was made minutes later, further stabilizing the grid. These ties restored the integrity of the southeastern Louisiana transmission system and made it possible for workers to carefully begin restoring load and additional generation for the area.

The Gustav experience points to how intelligent grid technology and real-time monitoring under disaster conditions can keep vital industries and services operating when they are needed most. The Department of Energy also recognized the essential role phasors can play in a truly smarter grid. Last November Entergy, the Midwest Independent System Operator (MISO) and ISO New England were among recipients of DOE funding to expand and enhance their phasor networks.

Hard experience and the current state of power system technology make it obvious that recovery operations centers are at the heart of efficient disaster recovery. If disaster takes a control center out of service, its functions

The entrance to Entergy's transmission headquarters in Jackson, Miss. The company moved key transmission system functions away from storm vulnerable coastal areas. The new headquarters building was completed last year.



must fail over to another control center so that all operating data is recovered quickly. It is for that very reason that Entergy last year completed its program to install automatic failover capabilities at its control centers.

Locating redundant control centers across a system in this way provides a high level of operational security and redundancy that was impossible a decade ago. The same realities that impelled the move to redundant failover capability for its control and data centers were also the driving forces in Entergy's strategic decision to relocate its transmission business unit's headquarters to Jackson, Mississippi, away from the storm-vulnerable Gulf Coast.

The industry is developing solutions like these, in some cases in collaboration with federal agencies, to address how bulk power systems need to function in the 21st century. In almost all cases, reliability and efficiency are tied to application of new information, energy management technology and cyber security.

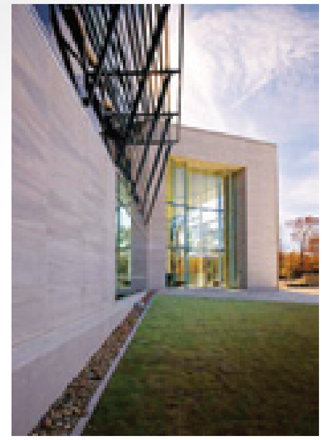
Put plainly, to reach its full potential a smarter grid will need information flowing two ways, instantly. To many outside of the electric power industry, the notion of a "smart grid" leads to a belief that it might somehow solve all environmental and economic problems, as the 30-second television commercials lead one to believe. On the contrary, this transition will be neither quick nor easy, and like most solutions, it will come at a cost that cannot be avoided.

Entergy believes a successful transition to a smart grid will take time, an evolution that begins with the electric power industry adopting and adhering to a set of consistent standards and protocols – a process that is already well under way. Entergy New Orleans was selected to receive $5 million of federal stimulus money for up to 11,500 smart meters, 8,200 in-home energy usage displays and 400 smart thermostats for low-income households within the city, a program that will evaluate the benefit and value low-income customers receive from AMI and demand response technology designed to help control usage and reduce costs.

A Kilowatt Saved is a Kilowatt (Not) Burned

The DOE smart metering grant program also focuses on another of the many unanswered questions around the smart grid, that being: Will it help or hurt those electricity consumers for whom the monthly light bill is a big part of their budget? Although the momentum to modernize the nation's transmission systems appears to be on track in Washington, DC, what is not known is how this affects customers for whom the monthly electric bill is a significant part of their personal budget.

It is Entergy's stance that just as investments in new generation or transmission infrastructure increase the reliability and security of its system, so too the company stands by its commitment to invest in ways that strengthen the communities it serves. And although it may at first appear to be somewhat counterintuitive in the current economic climate, Entergy continues its corporate social responsibility programs from environmental to corporate philanthropy, especially those aimed at its low-income customers.

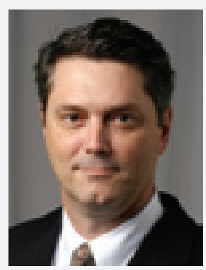


Federal statistics indicate that roughly 20 percent of Entergy's customers live in poverty – more than any other region in the United States. When working-poor families, the under-employed and seniors on fixed incomes are factored in, the number of ratepayers in need of help is staggering. The fact that 30 to 40 percent of Entergy's customers live paycheck-to-paycheck is a significant financial risk, especially given that customers pay for the power they receive only after it has been used.

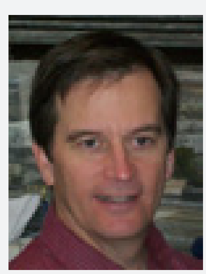
The low-income programs that Entergy supports are designed to help its low-income customers achieve economic self-sufficiency. The approach is a hand-up, not a hand-out. Helping customers become self-sufficient helps the company's communities, its bottom line and society. The changes the industry is now undergoing are preparing it to operate profitably in a fundamentally changed business environment.

As smart grid and grid transformation moves forward – as it undoubtedly will – efficient, affordable power will continue to be an essential element in any successful society. And in this new energy-constrained world, in many ways it will be up to the industry itself to change from being taken for granted to being understood and valued and to educate customers in meeting the challenges that lie ahead in a partnership for the future. ■

About the Authors



Mark McCulla was named vice president regulatory compliance in October 2008, reporting to Randy Helmick, vice president, energy delivery. In this position, McCulla is responsible for implementing programs, procedures, and controls to ensure Entergy's transmission business is in compliance with all federal and state regulatory compliance programs within transmission. McCulla holds a Bachelor of Science in Electrical Engineering from Louisiana State University and an MBA from Tulane University. He is a member of Institute of Electrical and Electronics Engineers (IEEE) and is a registered professional engineer in Texas.



Paul Cassingham is Manager, T&D Quality Control for Entergy Services, Inc., located in New Orleans, Louisiana. Paul holds a Bachelor of Science degree in Computer Engineering from Iowa State University and has over 29 years of experience in the utility industry including leadership roles in EMS/SCADA, continuous improvement quality programs, and asset configuration management. He is a senior member of the Institute of Electrical and Electronics Engineers (IEEE) and a registered professional engineer in Louisiana.

Geospatial Visual Analytics:

Helping Utilities Fight Back in Natural Disasters

By Mark L. Feldman, PhD, Chief Executive Officer
Space-Time Insight (Freemont, California USA)

Few events have highlighted the vulnerability of critical infrastructure like Hurricane Katrina, when it struck the Gulf Coast nearly five years ago. Since then, earthquakes, tsunamis, severe weather, wildfires and terrorism have been constant reminders that all critical infrastructure – whether communication, transportation, power, water, health care or dozens of other basic services – is at risk. Earthquakes devastated Haiti and Chile already this year while record snowfalls and storms have pummeled other geographical regions. Wildfire and hurricane seasons repeat annually. Frankly, the odds are against you, so it's time to even the playing field. Failure to do so can be catastrophically expensive in human, financial and reputational terms.

Nowhere is the vulnerability of critical assets more evident than among electric utilities, where sudden and prolonged outages can undermine and significantly set back the commercial, financial and human ecology of entire communities and regions. But, external forces are not the only villains in this scenario. Add aging infrastructure, an aging workforce, systems that don't talk to each other, proprietary systems that don't integrate well, systems that cannot differentiate between a security event and a malfunction, and you have a crisis waiting happen. There is more than enough culpability to go around for litigants and regulators.

Utility and ISO emergency operations centers and field teams respond to crises of varying proportions on a nearly daily basis. In the face of natural disasters, they take actions to mitigate the negative impacts on communities and commerce and remediate the damage to their systems and equipment.

For example, these organizations must take timely action to decommission endangered assets and re-route power to lessen the blow from wildfires that can take out critical infrastructure like substations and transmission lines and stop the flow of electric power to cities and hospitals. They must also quickly ascertain the impact of earthquakes, wind, flood waters, and ice storms on assets, employees, and customers.

And, they are responsible for keeping our critical infrastructure up and running, despite earthquakes, hurricanes, floods, and lightning, and they are responsible for keeping the lights on, communications flowing and transport moving for all of us.

Many critical infrastructure companies – energy, utility, telecommunications and transportation companies, and government entities – have access to multi-source geographical information to support effective disaster response. However, the geospatial technology is typically hampered by system constraints and not optimized for time-critical, fully informed disaster response. For example, essential information often resides in data silos that limit the integration, correlation and sharing that might otherwise produce timelier, context-sensitive and informed decisions and more confident actions toward problem resolution.

Figure 1: Screenshot of Space-Time Crisis Composite shows geospatial monitoring and alerting about fire locations, fires' relative priority status, last observed time, wind gusts and direction, relative humidity, fuel moisture levels, temperature, and proximity to critical assets and employees in the field workforce, enabling preventive mitigation and improved emergency response. Control room operators and supervisors can click to details or initiate action flows from the geospatial screen.

Figure 2: Space-Time Insight screenshot shows historical re-play of a hurricane over a utility's assets and the hurricane's impact on grid stability indicators for training and forensic analysis. Simulation features similarly enable scenario planning and training.

Some companies have multiple GIS systems with incompatible taxonomies documenting distributed assets in overlapping geographies. Integration of data from these systems is a punishing, manual process that is both time-consuming and frustrating – especially in a crisis. Moreover, it fails to support a unified level of situational awareness. Emergency responders, fire crews, control room and emergency operation center operators, and field service teams often have to manually integrate the information they require as the only way to piece together a complete picture of a given crisis situation.

In many organizations, the flood of data from sensors, enterprise applications, databases, and perhaps weather and other environmental feeds, is still neither integrated nor correlated to deliver the context-sensitive, condition-based information necessary to keep a crisis from becoming a catastrophe. Availability of multi-source data is one thing; making sense of it is quite another.

Today, organizations that have taken steps to integrate all the data they need in a common, correlated, analyzed and intuitive geospatial view benefit from improved ability to monitor infrastructure in the context of weather as well as other environmental and man-made crisis conditions in real-time. These tools have improved situational awareness, operational efficiency and effectiveness in responding to crises in ways that have been instrumental in preventing power outages, preserving water quality, minimizing disruptions to commerce, reducing destruction of property, and limiting loss of life. In most cases, it is this situational intelligence that provides the advantage they need to counter what is often enormous adversity.

Visually intuitive geospatial analytic solutions can now automatically sense and correlate real-time natural and man-made events such as earthquakes, fires, intense wind, sand accumulation, floods, storms, lightning strikes, explosions, and even unauthorized local activity. These systems can also deliver alerts and calculate both actual and projected impact on rural lands, population centers, and infrastructure. By enabling simultaneous integration of real-time streaming data from sensors, aerial photography, GIS applications, and other enterprise systems, these solutions deliver a level of situational intelligence and range of response that has transformed disaster response.

Interactive screens enable users to drill down for deeper risk analysis and finer detail while also launching remedial actions to initiate prevention, mitigation and remediation of pending and evolving events, while simultaneously recording adherence to established policy, operating practices and regulatory guidelines.

Organizations that can integrate real-time analytics with enterprise data and intuitive geospatial visualization have the data they need to inform better decisions, benefit from early warning, and gain an often critical advantage by having extra time to prepare for and mitigate a situation, thereby limiting its impact and accelerating remediation.

Further, with the addition of full-context, historical playback, users can replay past events on a geospatial screen for audit, forensics, training and planning for faster and more effective responses to future crises.

The geospatial future of disaster response has arrived. With the growing adoption of geospatial visual analytics and remediation software by critical infrastructure companies, the technology is continuing to evolve, incorporating new data sources and evolving with rapid innovation. Here are a few new technology trends.

State-of-the-art geospatial, visual analytics are evolving rapidly into the solution of choice for context-aware situational intelligence. The technology has become simpler and less technical, enabling faster adoption and more widespread use for everything from prediction to preparation, prevention and rapid response. Well-equipped organizations will enable everyone involved in disaster response to access the integrated information they need and collaborate – through browsers and mobile devices. First responders in communities will be able to share data with mobile field crews, and everyone responding to a disaster will be connected and informed and coordinated as never before.

Utilities and ISOs that have already deployed integrated geospatial, visual analytics solutions for disaster response describe impressive benefits. When California ISO accepted a geospatial project of the year award at the DistribuTech Conference in 2008, their executives were quoted saying, "It helped us keep the lights on." That following year, when San Diego Gas & Electric won the award, their executives stated: "We believe the project will improve our overall ability to respond to – or even avert – potential system emergencies in the future, and help us achieve our mission of providing safe and reliable energy to our customers."

Figure 3: Screenshot of Space-Time Asset Composite shows a pop-up screen, which appears after a user has clicked on an alert within the geospatial screen. The popup offers links to preventive and remedial action scripts and workflows, work permit forms, SCADA feeds, and video footage – enabling more effective resolution of an asset-specific issue.

Currently deployed state-of-the-art geo-links to onscreen action scripts will soon guide a higher percentage of operators through the steps necessary to mitigate and resolve problems before they become catastrophes. Each step will be logged and documented for automated incident reporting and documentation for regulatory compliance, audit, forensics, post-incident analysis and planning. More crisis response workflow processes will be configured based on approved procedures, and local practicalities for quick action in response to crises. This will save critical time and help ensure the most effective actions are taken.

Cloud-based collaboration will soon add even greater value. For example, a community first responder or a member of a field service crew can tap a location image in a smart phone or other mobile device and manually map the location of a wildfire to update the system in real-time with new information. This makes more accurate information available for disaster response, enabling reallocation or redirection of resources or communication of evacuation routes.

Twitter will be increasingly adopted as a real-time tool to aid in disaster response. Twitter's GeoAPI technology adds geo-signals to Tweets. Control center operators will be able to use the data from Tweet streams to get a better, faster, real-time understanding of what's happening in the field – seeing where and how people are affected by disaster events and tracking public perception. Disaster responders and utilities are already sending Tweets to the public and their customers to inform them of up-to-the minute updates on the location of an unfolding disaster and the progress of evacuation efforts and repairs.

Getting a fast, accurate handle on broad public perception will also enable responders to better communicate with the public. Early appropriate action based on good geospatial insight will give disaster responders, government officials, and utility companies enough time to mitigate the public response to a disaster before "crowd psychology" can take a negative turn.

Though natural disasters may appear to be getting worse and increasing in frequency, critical infrastructure companies have more solutions available to address them than ever before and to provide safe and reliable services to their communities, regardless of the circumstances. ■

About the Author

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AC "Ice Cube" Relays Applied for Improved Power Quality

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Industrial electrical equipment is often affected by power supply disturbances, most notably voltage sags. Numerous Electric Power Research Institute (EPRI) studies have found that common, general purpose AC relays often contribute to these electrical equipment shutdowns. Typically referred to as an "ice cube" relay due its clear plastic cover that resembles a square ice cube, these AC-powered relays may be susceptible to many voltage sags that do not affect other elements of a control system. Therefore, they present an "Achilles heel" that may cause an entire machine, processing line, or entire factory to shut down during minor voltage sags. This article discusses the basics of the common AC ice cube relay and documents the power quality issues related to these devices. It also presents EPRI's call for action to improve these devices in order to lower the worldwide cost of shutdowns caused by power quality problems.

Introduction

Control relays are essential electromechanical devices that activate one or more switches when their coils are energized. In the early days of industrial control, these devices were the primary component used in automation schemes.

Today, however, modern control systems often employ programmable logic controller (PLC)-based control systems to perform much of the logic-related work formerly done by the individual control relays. However, these simple elements are still heavily used in pilot relay applications in many motor-control circuits or when permissives or interlocks are needed between two elements, such as PLC and motor-control center, variable-frequency drive, or another separate machine or control system. Furthermore, control relays are heavily used in safety-related circuits where hardwired controls and interlocks are considered the best option.

Among the many types of control relays available, one of the most common types known as the *ice cube* is shown in **Figure 1**.

Figure 1: Typical AC Ice Cube Style Relay

The relays and contacts of these units are normally housed in clear plastic, which has the appearance of an ice cube. Ice cube relays with DC coils are generally resistant to common power quality problems as long as their corresponding DC power supplies are robust. However, ice cube relays with AC coils have shown themselves to be extremely sensitive to common power quality problems. With an average dropout at or near 70 percent of nominal for a cycle or less, these devices can lead to as many as 13 equipment shutdowns per year in a distribution-fed commercial or industrial facility. Example ranges of tolerance for these control relays have been documented in IEEE 1346 and are shown in **Figure 2**.

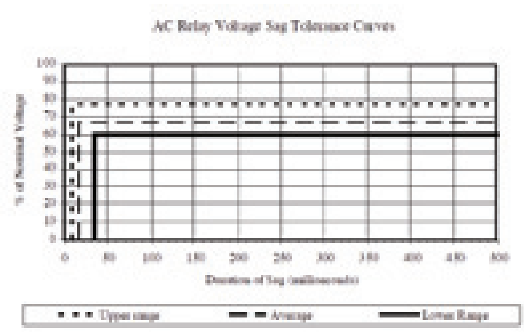

Figure 2: Example of the Range of Control Relay Sag Tolerances from IEEE 1346

EPRI has conducted detailed testing on AC ice cube relays as well. Those tests reveal the susceptibility of these relays to extremely short-duration voltage sags, even dropping out for events that are as short as ¼ cycle (4 milliseconds) to 1 cycle (16.67 milliseconds) in duration.

Because most fault events on the utility system cannot be cleared in less than 3 or 4 cycles, the relays are very likely to be effected by voltage sags. **Figure 3** shows composite test results of four off-the-shelf AC ice cube relays. The average response reveals that these relays are susceptible to minor voltage sags regardless of whether or not the sag begins at zero degrees at the voltage waveform or at the apogee of the voltage at 90 degrees.

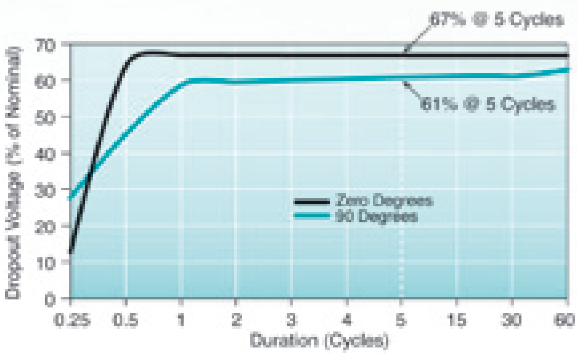

Figure 3: Composite Low-Voltage Tolerance of AC Ice Cube Relays (from EPRI Tests)

As a result of EPRI's previous system compatibility research, common industrial control components such as PLCs, drives, power supplies, and motor starters are now available that are compliant with industry power quality standards. Hundreds of off-the-shelf control components may be purchased that can survive voltage sags as low as the 50 percent of nominal and meet industry standards such as SEMI F47. The requirements of this standard are shown in **Table 1** and **Figure 4**.

Minimum Test Point No.	Sag Depth	Duration in Seconds	Duration at 50 Hz	Duration at 60 Hz
1	50%	0.2	10 cycles	12 cycles
2	70%	0.5	25 cycles	30 cycles
3	80%	1.0	50 cycles	60 cycles

Table 1: Required SEMI F47-0706 Test Points

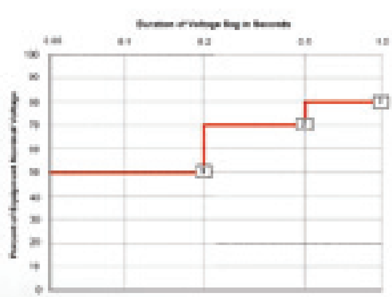

Figure 4: With the Exception of the AC Ice Cube Relay, Many Components Are Now Compliant with the SEMI F47-0706 Standard

Other standards, such as IEC 61000-4-11 and IEC 61000-4-34, call for categories of industrial voltage-sag tolerance down to 40 percent of nominal.

Unfortunately, there are no known AC ice cube relays on the market that are immune to voltage sags. While other control components have already made significant leaps in their ability to ride through common voltage sags, AC ice cube relays have not. Because of this limitation, significant power quality vulnerabilities continue to exist in modern machine designs where these AC relays find frequent application. Through power quality audits conducted in facilities worldwide, EPRI routinely finds that the reason for power quality-induced process shutdowns at a great many of these facilities is the simple AC ice cube relay. In fact, some plants may employ hundreds of these relays throughout their control schemes.

Typical General-Purpose AC Relay Design

A side view of a general-purpose relay, seen below in **Figure 5**, shows the relay to consist of an inductive coil forming an electromagnet, a frame allowing one or more pieces to pivot, and electrical contacts. **Figure 6** illustrates the mechanics of the relay, where **Figure 6a** shows the normally closed (NC) state with the spring's tension holding the contacts closed, while **Figure 6b** shows the coil acting to pull in the pivoting mechanism to switch the circuit. An electrical input activates the coil. (DC coils tend to be much more robust with regard to power quality issues than AC coils.)

Figure 5: General-Purpose AC Ice Cube

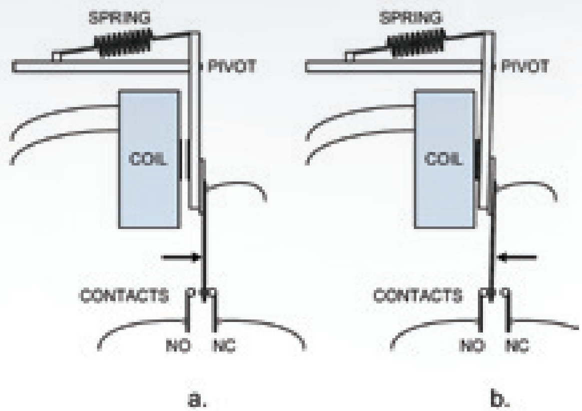

Figure 6: Mechanics of Normally Closed Relay

Typical specifications for general relays may be found in **Table 2**.

Brand	Operating Time	Operating Voltage	Voltage Sag Test Data % Vnom	SEMI F47 Compliant
A	10 ms	0.80 – 1.10 0.20 drop	63%	No
B	12 ms	0.85 – 1.10 No drop data	72%	No
C	25 ms	0.80 – 1.10 0.30 drop	72%	No

Table 2: Typical AC Ice Cube Relay Specifications

The data in the above table points out that the relays may activate or deactivate in one to two cycles of the power (one cycle is 16.67 milliseconds). While the relays above may operate successfully for around 80% to 85% of nominal voltage, a wide band of ambiguous operation exists between the minimum operating voltage and the definite drop-out voltage given. As the voltage-sag test data indicates, the relays were found to change states for voltage levels falling in the high side of this band, between 63% and 72%.

Example Impacts from Various EPRI Case Studies

Each year, EPRI's power quality group conducts numerous power quality audits at manufacturing sites worldwide. The prevalence of AC ice cube relays can be found at nearly all manufacturing sites. These relays are used for safety and control functions in many automated systems, as shown in **Table 3**.

Function	Application
Safety	Emergency Stop/Off Circuits
Safety	Flame Safety Interlock Circuits
Safety	Machine On/Cabinet Door Interlock Circuits
Safety	Master Control Relay Circuits
Control	Air Compressor Starter Controls
Control	Chiller Control Panels
Control	Conveyor Controls
Control	Heater/Oven Controls
Control	Logic Interlocks in Relay Control Panels
Control	MCC Motor Control Circuits
Control	PLC-Motor Control Interface Circuits
Control	PLC-ASD Run/Stop Interface
Control	ASD Start Circuit

Table 3: Common Function and Application of AC Ice Cube Relays

A few case studies are presented here to illustrate the problems encountered relative to the susceptibility of these relays.

Snack Food Plant

A processed food plant had deployed a high-speed mechanical transfer switch at a nearby substation with the ability to switch between two separate feeder circuits. Despite the switch, with a transfer time typically within two to three cycles, occasional power quality events led to equipment upsets and process downtime. The snack food plant hired EPRI to perform an on-site power quality audit to determine possible solutions that would allow the manufacturing systems to remain operational during power quality events.

Table 4 and **Figure 7** summarize the power quality events experienced at the facility over a 1.4-year interval.

Monitoring Period	1.4 years
Average Depth	77%
Average Duration	2.77 Cycles
Number of Events	59

Table 4: Snack Food Plant PQ Data Summary

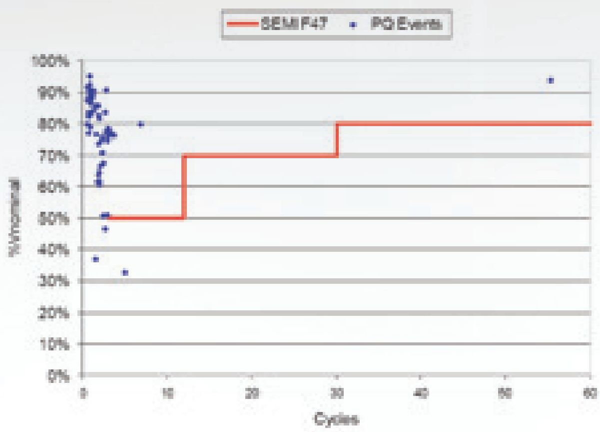

Figure 7: Snack Food Facility PQ Events

As can be seen in **Figure 7** above, nearly all of the voltage sags occurred at less than five cycles, with most at or below three cycles. The voltage sags of concern with regard to the ice cube relays in this facility fall below 75%. **Figure 8** shows the performance curve of a common ice cube relay (solid black line) overlaying the sag data of **Figure 7**. Around 16 of the voltage sags (i.e., about 11 per year) could have affected the relays used at this facility. If the AC ice cube relays in the control panel met SEMI F47, the entire panel would likely shut down less than two to three times per year due to voltage sags.

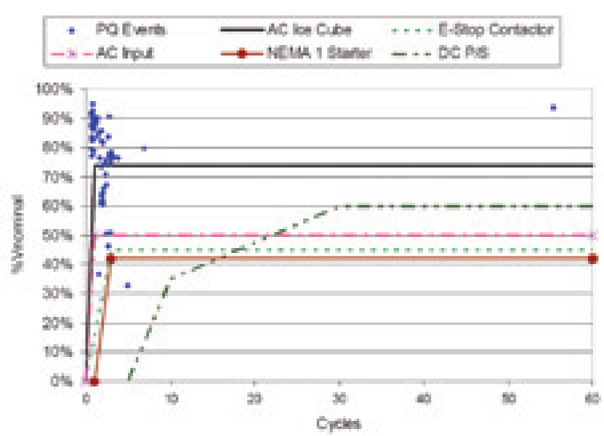

Figure 8: Voltage Sag Ride-Through Data of Various Components in Control Cabinet

Paper Cup Plant

Were AC ice cube relays only rarely used components, the problem they pose would be much smaller in scale. Unfortunately, these ubiquitous relays find application in most if not all electronically controlled industrial and facilities processes. **Figure 9** shows four AC ice cube relays in one of the 11 air compressor units used in a paper cup plant. The compressed air is critical to all operations because it is used by the machines for various actuators and to convey the cups from one location to another through a plethora of tube-like conveyors. For this reason, the loss of compressed air in a power quality event causes the entire plant operation to come to a halt.

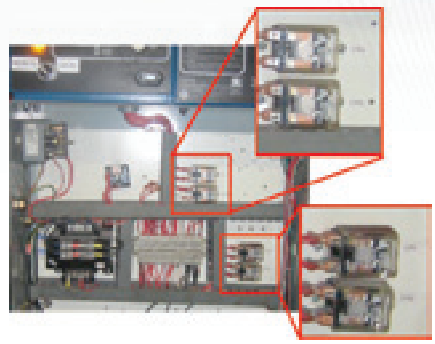

Figure 9: One of 11 Air Compressor Control Cabinets at a Paper Cup Plant

Figure 10 shows a line-to-line voltage sag recorded by a power quality monitor at the plant site. The recorded voltage sag was only 0.96 cycles in duration and was recorded to drop to a value of only 84.9% RMS. However, the actual depth of the sag approached 20% of peak voltage for ½ cycle of the event. This event shut down the plant air compressors thanks to the many ice cube relays in the control scheme.

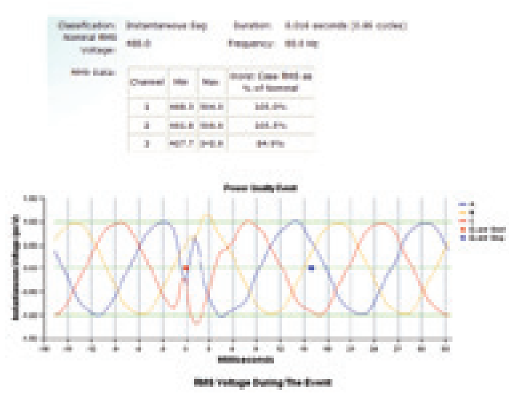

Figure 10: Short Duration Voltage Sag Led to Plant Shutdown due to the AC Ice Cube Relays

Semiconductor Plant

Relatively minor voltage sags can cost a semiconductor plant a million dollars or more. In the late 1990s, EPRI conducted a research project to look into the reason why semiconductor tools were susceptible to voltage sags. Surprisingly, the main reason that most equipment was found to shut down during voltage sags was directly related to the use of AC ice cube relays in their emergency off (EMO) circuit designs.

The EPRI research revealed that of the initial set of 33 tools subjected to voltage-sag testing, almost half were found to shut down due to the effect of voltage sags on the AC ice cube relays used in the EMO circuits, as shown in **Table 5**, following.

Voltage Sag Susceptibility Ranking	Area	Overall Percentage
1	*EMO Circuit*	*47%*
2	DC Power Supplies	19%
3	3-Phase Power Supplies	12%
4	Vacuum Pumps	12%
5	Turbo Pumps	7%
6	AC Inverter Drives	2%

Table 5: Most Common Sources of Voltage Sag-Related Shutdowns in Semiconductor Tools (from EPRI Research)

Typically driven by the smaller EMO pilot relay, the main contactor is used to apply power to the semiconductor tool (**Figure 11**). If the EMO relay was designed with an AC ice cube unit, the entire tool was found to lose power during many of the voltage-sag tests. This finding helped to lead to improvements in 300-mm semiconductor tool designs. Thus, most 300-mm semiconductor tools are compliant with the SEMI F47 standard. Ironically, due to improvements in wafer-processing technology of 200-mm equipment and economic forces, the lifespan of the 200-mm tools has greatly exceeded what was expected. Therefore, many of the 200-mm designs are still in operation and being supplied to plants today with the vintage EMO circuit designs that include AC ice cube relays.

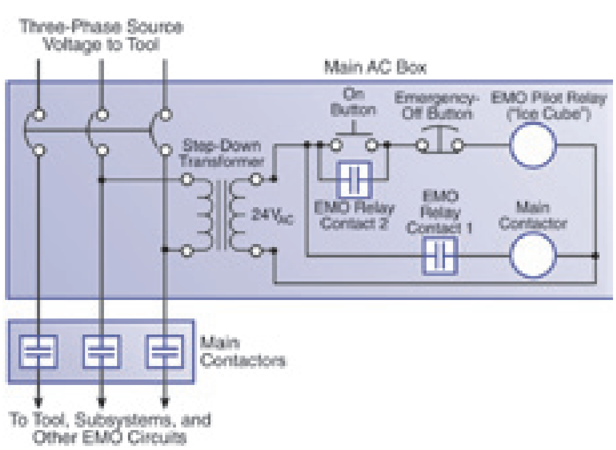

Figure 11: Typical Emergency Off Circuit (Simplified)

Call for Improvement

Modern industry requires a better-designed alternative to the standard AC ice cube relay. If SEMI F47-compliant units are made available, many power quality-related shutdowns could be avoided. Furthermore, industrial plants could be expected to save from several hundred thousands to several millions of dollars each year in downtime and lost revenue. Worldwide, such improvements could have a significant impact.

For this reason, EPRI is calling on the manufacturers of control components* to develop a line of control relays with improved voltage-sag robustness. Ideally, the market cost of the improved relay should not be such that it would inhibit widespread adoption by industry.

In general, the improved designs should meet the following criteria:

1. The units should be compliant with the SEMI F47-0706 voltage-sag standard, which requires hold-in capabilities down to 50 percent of nominal for the worst-case test point. The units can drop out for voltages less than 50 percent of nominal.
   a. Units that can meet the more rigorous requirement of 40 percent of nominal hold-in (IEC 61000-4-11 and IEC 61000-4-34 standards) would exceed the base requirements.
   b. Manufacturers who would like to take on this additional challenge are encouraged to strive for the 40% of nominal hold-in voltage.
2. The units should not exceed the physical footprint of existing AC ice cube relay designs with the same number of contacts.
3. The units must require "AC" power to operate.
4. The units should provide standard contact forms such as double-pole double-throw (DPDT), 3-pole double-throw, and 4-pole double-throw.
5. The units should utilize standard socket and pin formats such that the new units can easily retrofit and replace relays in existing applications.
6. The pull-in and drop-out operation time of the units should be similar to those of common AC ice cube relays in order to match existing applications. Typical specs range from 9 to 25 milliseconds.
7. The dropout voltages should be consistent with typical specifications. Typical specs range from 10 to 30 percent of nominal.

(*Manufacturers who would like to engage in this effort to design and demonstrate their ability to meet or exceed these requirements should contact EPRI.)

The EPRI role in this effort would be threefold:

1. Provide a test bed for demonstration of the voltage-sag ride-through performance of the new relay designs. Perform testing and document performance, providing feedback to participating vendors.
2. Develop a demonstration effort for actual field application for prototype units where they would be used as replacements for existing ice cube relays in control system applications, documenting performance of the improved designs.
3. Coordinate through electric utility funders to provide appropriate information for customers (white papers, brochures, summary test results, case studies, etc.) for the improved performance that is possible with the new technology. ■

About the Authors

Mark Stephens, PE, is a senior project manager at EPRI for Industrial Power Quality in Knoxville, Tennessee. Mr. Stephens manages research and services work related to Power Quality at EPRI. He is a member of several power quality standards working groups in IEEE and CIGRE. With over 21 years of professional experience, he has solid design experience in industrial control system design, programming, instrumentation, equipment installation and startup and leads EPRI's related efforts in the Power Quality arena.

Stephens received a BSEE from the University of Tennessee in 1988 and has been a registered professional engineer in the state of Tennessee since 1995.

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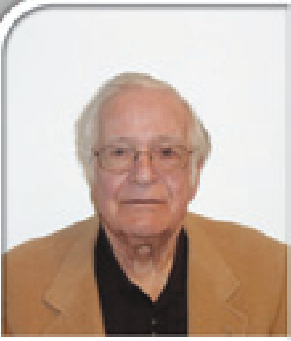
Wright received a BSEE from the University of Tennessee at Knoxville TN and earned his professional engineer license and is a registered certified energy manager (CEM).



A Brief History of Electric Utility Automation Systems

By H. Lee Smith, PE
Life Senior Member IEEE

Many people assume the Smart Grid is a revolutionary change to the operation of the electric grid. In reality, it is an incremental step in the long evolution of adding automation to the electric grid. This general overview presents a history of Electric Utility Operational Control Systems. It spans from the early adaptation to the current era of the Smart Grid. The discussion is presented in two sections: Monitoring-Control Systems and Communication Protocols. A final section integrates these two technologies into the Smart Grid and includes some lessons learned from early implementations. This brief review will not include the automation applied by protection systems and devices.

Operational Automation Systems

There are three generic parts to the operational automation system: The Master Station (central/host location), the Remote Interface Devices – commonly referred to as Remote Terminal Units (RTUs) – and the Communications System. Each is summarized in the following sections.

Master Stations

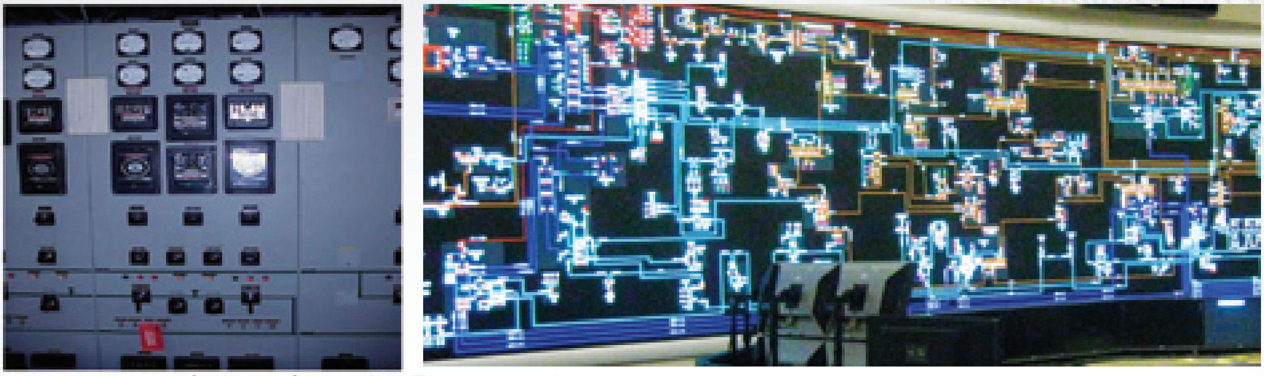
Some of the earliest Supervisory Control and Data Acquisition (SCADA) systems were installed in the 1920s. At the time, some high voltage substations adjacent to power plants (aka generating stations) could be monitored and controlled from the power plant's control room. This eliminated the need to staff the substations 24/7 even if the substations were some distance from the power plant control room. These systems consisted of two control and monitoring boards, one in the substation and one in the power plant. Eventually the power plant substation board was reduced to a single panel that could be multiplexed to each of the substation control panels. Power plant governor control – used to change the output of a generator – was essentially a manual operation based on instructions from the System Control Center.

In the 1930s, individual utilities started interconnecting to interchange electricity to reduce operating costs. With this came the need to control generation much more closely, so analog computers were developed to monitor and control generator output, tie-line power flows and frequency.

By the 1950s the analog computers were enhanced to schedule generation to each generator to provide the lowest cost of generation. These functions were called Economic Dispatch (ED) and Automatic Generation Control (AGC), and the systems were labeled Energy Management Systems (EMS). The EMS functions were supported by off-line manual calculations to determine which company could produce the next block of energy at the lowest cost. Negotiations were then conducted between the utilities to set the tie-line power flow schedules.

In the late 1960s, digital computers and software were developed to replace the analog EMS systems. Software applications were developed to include the off-line analysis functions along with transmission system analysis models. Vendors modified the computer supplier's operating system to meet their design and each set of application software was usually unique for each customer. Thus, when the computers needed to be upgraded or more functions were required the entire Master System had to be replaced. This trend continued into the 1980s and 1990s until open standard operating systems were developed that supported real-time applications.

Some utilities worked with vendors to develop and deploy hierarchical control systems. The lower level systems monitored and controlled portions of the transmission and distribution grids. This reduced the EMS database size and the amount of information communicated to the EMS system.



Control Systems: Then... and now

More recently, some utilities have deployed distributed control systems with area transmission and distribution control centers. Other utilities have installed regional DMS (Distribution Management Systems) which communicate with distribution substations as well as with feeder devices (i.e., reclosers, capacitor bank controllers, sectionalizers and feeder voltage monitors). Today, communications to feeder devices is usually wireless. These systems provide closer contol of feeder voltage profiles and faster determination of faulted feeder sections to improve service restoration times.

Some utilities are also deploying master stations into T&D substations. These substation master stations may operate independently for some automation functions and as slave devices for other functions, with the ultimate control being assigned to the network operations center.

With the move to Open Market operations, there have been shifts in the locations where various operation and monitoring functions are performed. The generation control functions, in many cases, have been moved to Independent System Operators (ISOs). The transmission analysis operation functions have been transferred to ISOs or Regional Transmission System Operators (RTOs). However, some utilities still operate in the traditional manner with integrated generation, transmission and distribution control systems.

Remote Terminal Units (RTUs)

In the early application of monitoring and control systems, the interface between the power system and the control system was in a remote location. This interface was designated a Remote Terminal Unit – or RTU. An RTU consisted of a cabinet or panel of terminals for the instrumentation and control wires, which connected it to the power system. The position of the power system switches and circuit breakers were monitored by auxiliary relays. When the relay was closed, the power system switch was closed and a current was present resulting in a binary "1" signal. When the relay and the switch were open the binary count was a "0". Analog values were obtained from potential transformers and current transformers connected to the power system buses and circuits.

The transformer output was 120 Volts AC and nominal 5 Amperes AC; these values were converted by transducers to +/- 1 milliampere DC. The RTU had analog devices to convert the analog values into binary values (usually 8 to 12 bits).

Thus, the digital and analog input values from the power system could be sent as a series of binary values to the master station for display and analysis purposes. The auxiliary relays in the RTU used for controlling power system devices were addressable so the operator could select the address for a specific power system device and function, (open or close) and send the command to the RTU.

The RTU remained basically the same until the mid-1970s when rugged microprocessors that could withstand the substation environment became available. The application of microprocessors reduced the hardware complexity of the RTU, but the interface wiring remained unchanged, or even increased as the external milliamp transducers were replaced by internal analog to digital converters. The use of these analog-to digital (A/D) converters required that the AC secondary amperes and voltages be brought to the RTU.

The use of microprocessors provided the opportunity to greatly increase the capabilities of the RTU. These capabilities included time keeping, more complex and powerful protocols, individual point numbering, local logging and time tagging of events, higher communication speeds, multiple communication ports and numerous other functions. But the complex and costly interface wiring continued to exist and kept costs relatively high.

In the 1980s, microprocessors began to be applied to protective relays, meters, various controllers and other devices, which usually were equipped with a communications port. As these more powerful devices were deployed, the utilities and system vendors both realized the substation design and complexity could be greatly simplified by interfacing these devices directly into the RTU. Thus, a new era of opportunity began to unfold. It was also a time of confusion and frustration (as will be discussed in the protocol section). As the application of these devices grew, the IEEE Power and Energy Society (PES) Substations Committee determined that a need existed for a unique name to identify them. It was at that point that the term Intelligent Electronic Device (IED) was coined and defined. Soon, almost any device with a microprocessor and a communications port was deemed an IED.

As the application of IEDs spread to most new substations as well as many updated substations, they quickly became the preferred interface between the power system and the RTU. The application of these devices greatly reduced the magnitude and complexity of the control and instrumentation wiring. In the 1990s, utilities began installing IEDs on their distribution feeders with some communicating to the substation RTU while others communicated directly to the network operations center. In both cases, this extended the reach of their control systems down to the distribution feeder level.

Currently there are tens of thousands, if not hundreds of thousands, of these feeder IEDs in operation that are regularly polled by the SCADA master for updated analog and status data. While these remote IEDs provide monitoring and control capabilities to the system operator, there is little or no automation. Adding intelligence and automation to the distribution feeders is a vital next step leading to the Smart Grid.

Communications Systems

Early utility monitoring and control systems were structured around telephone technology and used leased telephone lines operating at 300 bits/second. Leased phone lines are still the most common communications system element. Many are still operating at 1200 bits/second, but some have been upgraded to 4800 bits/second and a few to 9600 bits/second. Several utilities have even installed private telephone systems with high-speed switching and automatic fault recovery capabilities.

Early on, utilities faced the problem of communicating to very remote hydroelectric power plants, and installed power-line carrier systems between high voltage substations to solve the problem. These systems carried both voice and data, which solved the problem as long as there was a direct link between the two substations. Most of these systems have probably been replaced with microwave. Utilities with large geographic areas have private microwave systems to handle large volumes of information over long distance communication links.

A few utilities have implemented satellite communications for sparsely populated large geographic areas. Fiber optic cable is being used both within substations and as Wide Area Networks (WANs). With the recent concerns about security this is becoming a more attractive and cost effective solution.

Starting in the 1980s, licensed 900 Megahertz point-to-multipoint radio systems became very popular, especially for small substations. These systems provided a substantial cost savings over leased phone lines and were under the complete control of the utility company.

In the 1990s, unlicensed 900 Megahertz mesh radio systems were installed and added to the communications network mix. The first (skeptical) reaction was that these radio systems provided undetermined communication response times and were not suitable for monitoring and control. However, with proper designs and management, these systems have subsequently been proven to meet most requirements.

About the only thing that is certain about utility communications systems is that they usually have a mix of everything. The trend is to add higher speeds with more throughput capacity, but even many large utilities are still operating with 1200 bits/second leased lines.

Protocols

The protocol is the glue that holds everything together. If you have tried to communicate using American English in England or Mexican Spanish in Spain, you understand the potential for problems. The electric utility industry has gone through many phases with protocols for control systems.

In the beginning, there were only a few companies that made hardware-based systems, and practically no one considered interoperability. As digital systems came into play there were more vendors, many of which stayed in business for only a short time, causing concern about interoperability to increase. Also, there was a need to make the protocols more robust and more secure.

The major system suppliers solved part of the problem by documenting their protocol and permitting customers to share it with RTU suppliers. In the 1980s, there were perhaps six or eight shared protocols and another four or five proprietary protocols along with a few "utility-unique" protocols.

When IEDs began to be marketed, the number of protocols exploded like a mushroom cloud. Each new vendor invented a protocol for their device; some even invented a new protocol for each new model. System vendors and utilities were going crazy trying to integrate these IEDs into their control systems. One RTU vendor listed 100 protocols the company had implemented. In the late 1980s, the IEEE PES Substations Committee formed a Working Group (WG) to investigate this problem and to determine a reasonable solution.

The WG developed a list of requirements that a protocol should satisfy to meet the needs of the industry. Information was collected from around the world on 120 potential protocols, which were then screened against the list of requirements. Only about six or seven passed the screening. The WG held a ballot and two were selected: Distributed Network Protocol version 3 (DNP/3) and IEC 60870-5-101. The proposed selection of these two protocols was balloted by the IEEE, and in 1997 IEEE Standard 1379 "Trial Use Recommended Practice for Communication between RTUs and IEDs" was adopted and published.

IEEE 1379 was reaffirmed as a Recommended Practice two years later. It has since been reaffirmed (in 2006). DNP3 is now the most widely deployed and specified protocol in North America, not only for substation use, but also for substation to master station communications. In parallel with this activity, the ownership and maintenance of the DNP3 protocol has been under the control of the DNP Users Group, an open membership not-for-profit corporation since 1996.

The enhancements recommended for the protocol by the Technical Committee and approved by the membership have led to its wide scale acceptance and to enhanced functions. Cyber security features developed by the IEC, Technical Committee 57 (TC57) Working Group IEC 62351-5 have been added to the DNP3 protocol and are presently being tested for performance.

There are two other IEC activates that are sometimes mentioned in relationship to the Smart Grid: IEC 61850 Substation Communication protocol and the Common Information Model (CIM) IEC 61968 and 61970 models. The CIM models should be considered for use by all utilities, since they define the basic elements of the grid and their interconnection and perhaps efficiently to the GIS system. However, it will be extremely important to have a digital database system that can provide data to the Smart Grid control system.

The IEC 61850 protocol includes a number of features that should be considered for any control system – the object definitions and concepts, the use of XML files for defining IED and master station databases and the naming conventions – to list a few. IEC 61850 also includes many functions and features that are related to substation protection systems that may limit its suitability for remote to master communication. It should be noted, however, that some North American utilities are using DNP3, Modbus and IEC 61850 GOOSE (Generic Object Oriented Substation Event) messages on the same substation LAN. This might be called using the best of three worlds.

Lessons Learned

Automation has been applied to distribution system feeders for a long time, especially as related to protection and the restoration of some parts of the feeder. The question now is how can more intelligence be added to get more customers back in service sooner? Some small-scale deployments using rule-based artificial intelligence engines have been very successful. However, there were some learning points along the way…

- In addition to monitoring the power grid, the communication network must also be monitored.
- Power system devices must be properly maintained to ensure they are in operational condition.
- All devices with battery backup systems must be automatically tested to ensure the battery's capability to support the device.

System operators must be included in the design of the automation logic so they can…

- Understand how it works and when it will work,
- Understand it is not a replacement for them, but a support tool,
- Understand they have control over the logic; not visa versa.

In summary, the Smart Grid era is not a destination but rather a point of departure for the energy automation field. The Smart Grid will add another layer of automation between the protection system and the System Operator, doing the simple rule based things and leaving the complex problems to the Operator. Professionals serving this field will continue to adapt and invent to meet the challenges of ever changing demands of users. The Smart Grid integrates the components of past developments. However, those components are not an orderly unit.

In reality, the components integrated into the Smart Grid are as varied and as diverse as the history of energy automation. The future promises opportunities to refine and to extend the efficiency and the effectiveness of present – and yet to be defined – components.

Based upon the past ingenuity and determination of those developing the energy automation systems, there is no doubt these opportunities will be met with a wealth of new ideas and new products.

It is critical to keep in mind that the Smart Grid applications will, in all probability, be additions to – not replacements of – existing facilities. The investment in current control systems is huge, and it is performing its intended functions. Failure to integrate Smart Grid to the existing infrastructure (i.e., rather than trying a complete replacement or overlay) is probably doomed to be an expensive failure.

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Using Location Intelligence in Advanced Customer-to-Network Relationship Management to Ensure a Better Level of Smart Grid Service and Reduce Cost-to-Serve

By Jeremy Peters, Solution Architect, Pitney Bowes Business Insight

Utilities are increasing investment in Smart Grid technologies and smart metering projects as a result of the rising demand for electricity (particularly in developing economies), aging T&D infrastructure in developed countries, emissions and climate change mandates, and the need for real-time visibility of energy supply and demand to optimize both service reliability and cost. Government regulations and incentives are contributing to this rising investment and interest in alternative energy sources and Smart Grid infrastructure in numerous countries around the globe. The Provincial Government of Ontario Canada has targeted the end of 2010 to deploy smart meters in all businesses and households throughout the province.

The Smart Grid is concerned with optimizing the performance and management of electric transmission and distribution networks to improve reliability, reduce costs, drive energy efficiency, promote energy-saving choices for consumers and foster the growth of renewable energy sources. The Smart Grid is made up of many technologies working together in an integrated enterprise utility solution with location-based technologies playing a key role. Technologies such as smart meters, integrated communications, sensors, distribution management, Supervisory control and data acquisition (SCADA) and advanced metering infrastructure (AMI), among others, make up the Smart Grid.

Customer relationship management (CRM) solutions help utilities perform critical tasks related to the acquisition, development, service and retention of their customers. The early effective adoption of location intelligence in advanced CRM solutions by utilities will play an important role in the successful implementation of the Smart Grid. Location intelligence in Smart Grid solutions will provide real-time decision support systems able to analyze the network, determine the current state and condition of the system, predict what may happen, and respond accordingly in order to effectively communicate the state of the system from the sensor network to both the utility and the customers. The adoption of location intelligence in advanced CRM solutions will help ensure a better level of service using smart grid technologies and reduce cost-to-serve by:

- Providing a standardized and validated enterprise-wide view of customer information with accurate customer locations in relation to the electric utility system
- Maintaining true spatial accuracy, alignment and integrity between the spatial referenced data overlays such as land base data, network data and customer data
- Geographically visualize and understand the electric utility system's relationships, connections and patterns
- Monitoring the real-time status of the grid on an interactive map and highlighting where the system status is changing
- Providing Enterprise Risk Management and real-time analytics for system restoration, storm tracking and security monitoring
- Enhancing market-driven network planning with spatial analysis to help determine the most cost-effective and profitable design of the Smart Grid
- Increasing the efficiency of customer service provisioning and activation

Enterprise wide view of customers with accurate customer locations

A consistent, single view of a utility's customers across the enterprise with accurate and complete customer information is crucial to effective customer relationship management. Poor quality customer addresses can be costly and will affect billing and cash flow, service delivery and customer relationships. An address quality system is needed to accurately locate customers geographically and in relation to the electric network in order to accurately represent those customers as connections to the Smart Grid. Only then can the Smart Grid optimize the automation of system management and restoration to improve reliability, reduce costs, drive energy efficiency and empower consumers.

Address cleansing and geocoding (assigning a latitude and longitude to an address) technologies enables customer service representatives to execute address validation, postal certification, standardization, correction and geocoding in a batch and/or real-time environment as data is being entered into customer care and billing systems. Advanced geocoding technologies now use address point interpolation to improve upon regular street segment interpolation by inserting point data. When an address point user dictionary is present an address can be geocoded at the correct property location as opposed to the approximate location on a street segment. Property records and accurate parcel boundary definitions provide important ownership information and the accurate geographical representation of the connection between the customer and the electric network.

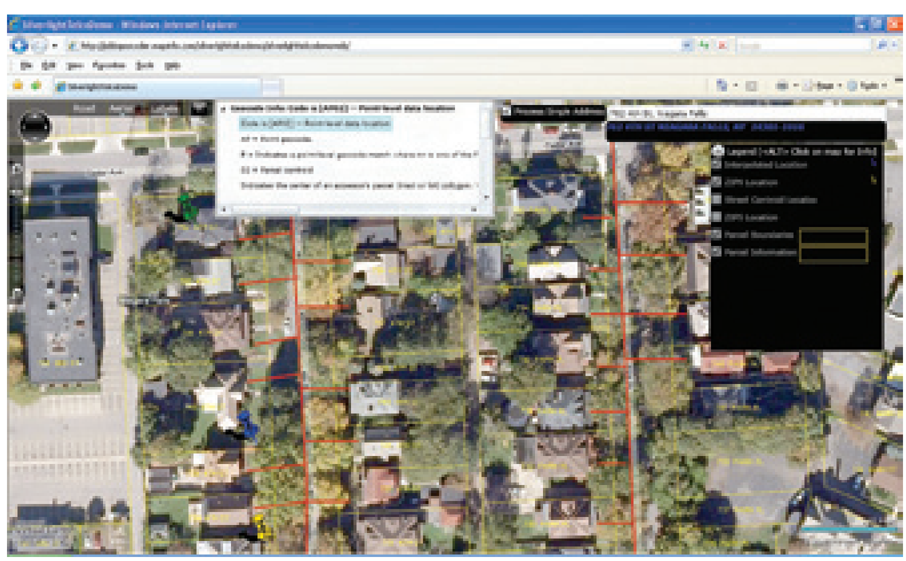
Data entry errors by both employees and customers, along with inconsistencies, contribute to a utility's data quality problems. Data problems include: poor quality, reconciliation, reporting compatibility, confidence, and accuracy and reliability issues. Data quality also plays an important role in service optimization, network planning, customer service and operations. Location Intelligence is a key component in many utility providers' enterprise information management (EIM) strategies. Utilities must have an enterprise data quality system that enables them to leverage the most up-to-date, accurate and complete view of customers across the organization. Effective quality assurance processes include five best practices

- Data Profiling
- Data Governance
- Back-End Cleanup
- Interactive Processes
- Maintenance

Customer data quality/data integration technologies improve the completeness, validity, consistency, timeliness and accuracy of customer data by enabling these best practices. Customer data quality leverages capabilities such as – name parsing, name standardization, and name validation, unique entity identification, address cleansing, geocoding, data consolidation, geography code assignment and tax jurisdiction assignment. Some of these advanced enterprise data quality systems are based on a service-oriented architecture (SOA) and provide a graphic rule editor interface so that you don't have to write any code to customize businesses processes to a utility's specific needs. Ensuring that customer data is accurate, complete, and up to date enables utilities to better understand their customers, provide a better level of service and reduce cost-to-serve.

Maintain true spatial accuracy, alignment and integrity between land base, network facility and customer data

For use in a Smart Grid system that automatically controls the electric distribution system, utilities must maintain true spatial accuracy, alignment and integrity between spatial referenced data overlays such as land base, network facility and customer data.



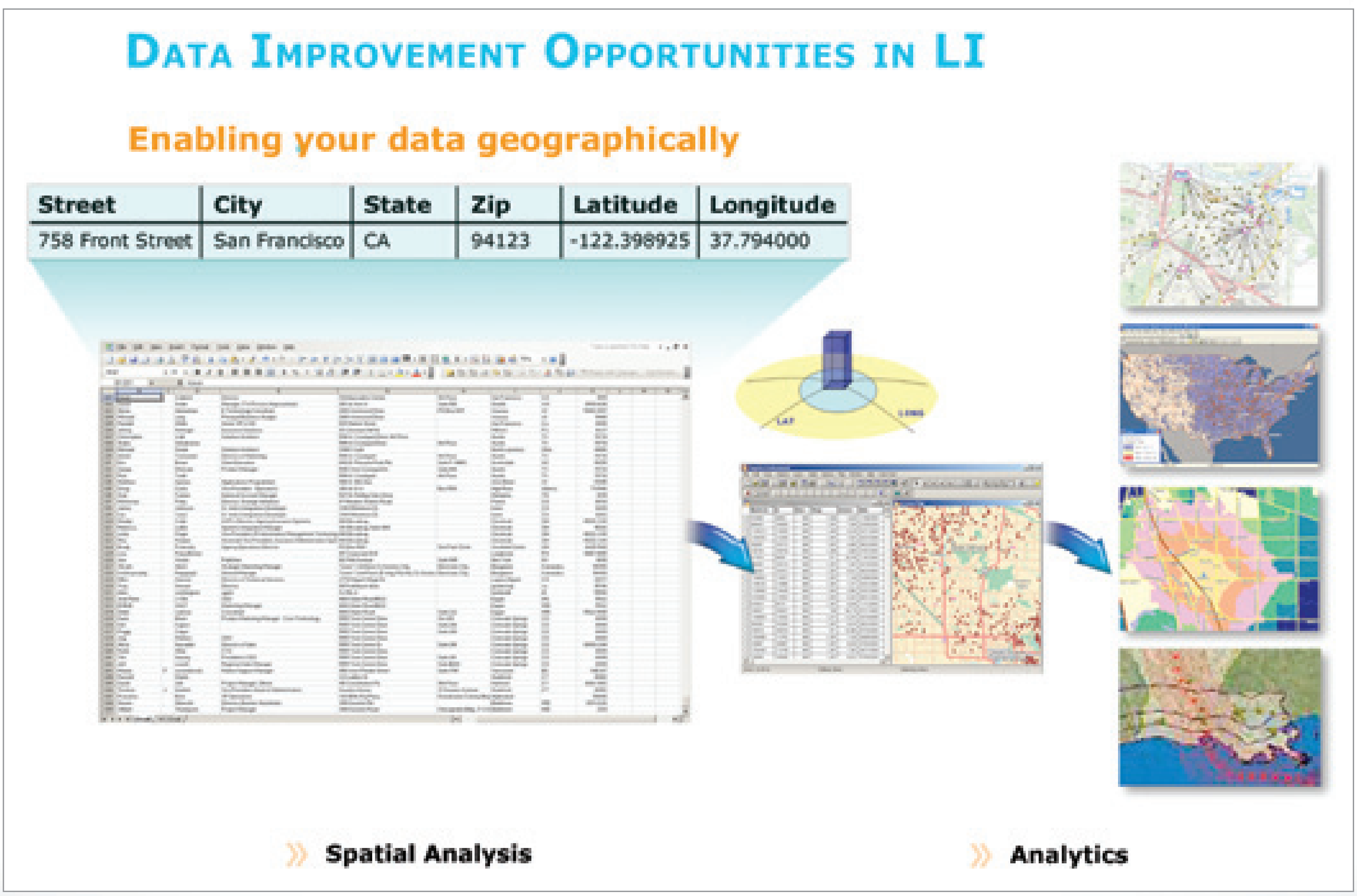
An accurate point level geocode of a customer's address is represented by the green push pin on the map, along with property boundaries, and connectivity to the Smart Grid network.

Powerful location intelligence/GIS software enables utilities to the map out the accurate location of network assets in relation to a land base and customers through their completed engineering life-cycle model, from point of conception to retirement.

A spatial data management system is needed to store, manage and serve the geographic objects and all the historic and real-time data about the system assets from Smart Grid meters and sensors. A spatial data management system is a core component of a location information system (LIS). Utilities can effectively optimize core Smart Grid components when their network assets are accurately mapped, stored and maintained.

Geographically visualize and understand the relationships, connections and patterns in the electric utility system

The LIS is the source for network asset and land-base geographic information and is integrated into other core utility systems, such as outage management, distribution management, work force management, customer service, enterprise asset management (EAM), network planning, advanced metering infrastructure (AMI) enabled billing and CRM. The LIS mapping and spatial analysis capabilities are accessed using desktop applications, Web-based applications and mobile device applications via secure client-user interfaces. Web 2.0 geospatial "mashup" map tiling frameworks, such as PBBI Stratus, Microsoft Bing Maps, Google Earth are among the latest implementation frameworks that can be used to provide basic capabilities to view, analyze and manage geographically based network asset and customer information and the relationships that exist between them.



View, analyze and manage geographically based customer and Smart Grid asset information to support operational decisions and reduce cost-to-serve

More powerful geospatial capabilities can be integrated into these frameworks from LIS/GIS platforms. These platforms provide the ability to fully illustrate and analyze the relationships, connections and patterns in the Smart Grid, thereby enabling utility leaders to make better planning and operational decisions for their customers. These capabilities provide a powerful means for visualizing and analyzing the spatio-temporal trends of the Smart Grid system metrics over time. Some of the key characteristics of these Web 2.0 geospatial solutions include:

- Desktop user experience over the Web using technologies such as Flash, Silverlight and JavaScript, OpenLayers, Mash-Ups and Ajax for partial-page updates
- Map tiling to enable caching land base and network assets for superior map display performance and interactivity
- Flexible standards-based location intelligence Web services SOA architecture
- Flexible map tiling frameworks client side JavaScript programming APIs that enable quick and easy integration of rich web-based geographic capabilities into client applications
- Accurate and aesthetically appealing land-base maps with easy data refreshes including hundreds of terabytes of aerial and satellite imagery for better spatial context

Monitor the real-time status of the grid on an interactive map and highlighting where the system status is changing

The Smart Grid can enable a more advanced, integrated outage management system and distribution management system (OMS/DMS) to analyze and optimize the network and identify, respond to and resolve power outages quickly and with significantly less impact to customers.

Integrating advanced technologies, such as location intelligence and automated meter reading (AMR) with OMS/DMS and workforce management systems can enable the automatic pinging of customer meters to quickly detect if and where there is an outage to significantly improve outage response times and to enhance customer service. Location intelligence linear referencing and dynamic segmentation capabilities, found in some Web-based mapping application development tools and solutions, can be used to determine the location of a fault more accurately by measuring the optical distance along the fiber.

These capabilities can also be used to better monitor and analyze assets, conditions and events that exist along network. Such a system can show a real-time view of location dependent critical network elements on an interactive map and automatically highlight where things are changing in order to communicate real-time network status, network quality, and trouble tickets to service and support representatives across the organization.

Utilities will be able to make better decisions based on easily visualized, actionable intelligence from the sensor network and the smart meters about outages, restoration, load, events, voltage, current, equipment failures and other potential issues detected along the distribution network. Using location intelligence capabilities, the entire network and its status can be viewed at any moment to instantly see developing problems, locate the nearest repair crew and reroute them to exactly where the outage is located.

Enterprise risk management and real-time analytics for system restoration, storm tracking, and security monitoring

The DMS will provide the automated engine to analyze and optimize the distribution network using location intelligence. The Smart Grid will optimize distribution based on easily visualized, actionable information from thousands of sensors and the smart meters after an abnormal event to prevent equipment failure and outages. The Smart Grid will also take preventive measures to mitigate risk based on current and historical intelligence about load and the condition of network components, such as transformers. Smart Grid algorithms that incorporate spatial analysis will be part of a decision support system that can help determine risk, customer impact and recommend preventative measures.

Electric utility providers also need to assess, understand and mitigate many other different types of risk, such as weather, crime, terrorism, political, financial and regulatory related risk.

Utilities can view weather occurrences in real time in conjunction with their network assets, their customers, and their repair crews and supplies to see what is actually happening at their asset locations by integrating real-time WMS Web service weather feeds into their LIS capable OMS/DMS. Real-time and projected hurricane paths can be mapped and analyzed to show the probability and estimated magnitude of the hurricane in relation to the electric system and their customers. This allows utilities to make better decisions regarding the management of both large-scale and localized weather disruptions.

Data on both historic and current weather, wild fires and earthquakes, as well as political and crime risk is also available for enterprise risk analysis. This data can be analyzed using location intelligence for long-term planning to better understand potential risk. Historic risk data allows electric utility providers to better understand the potential for loss or interruption based on knowledge of wild fires, earthquake fault lines and zones, as well as historic weather data on the location of previous hurricanes, hail storms, wind events and tornados.

Crime risk data can be analyzed to locate the safest areas for company assets and to ensure employee safety and security. Using location intelligence, electric utility providers can access data that models the risk of terrorism to create action plans or establish "what-if" contingency plans. Access to such vital data helps providers make important decisions to:

- Re-allocate assets/resources, control liabilities, secure network infrastructures to prevent potential outages
- Establish priorities for service restoration
- Determine optimal locations for new assets to minimize structural and employee risk

Using spatial analysis to enhance market driven network planning

Location Intelligence provides the tools to help determine the most cost-effective and profitable design of the Smart Grid by modeling alternative builds-out as driven by customer needs. Utilities will need LI to determine the optimal location for Smart Grid components, such as, new communication backbones, repeaters and sensors. Location Intelligence provides an effective means to help see where network investments are needed and determine how much capital is required for build-outs because optimization depends heavily on the relationships between existing location based infrastructure, customers, land base and environmental factors.

Conclusion

Location intelligence in Smart Grid solutions will provide real-time decision support systems able to help utilities plan, manage, predict and make decisions with greater accuracy, efficiency and reduced cost. In the end, location-based technologies will help utilities unlock the value of facility, land-base, customer and environment data to enable the Smart Grid, help ensure a better level of service and build profitable customer relationships. ■

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Jeremy Peters is a Solution Architect with Pitney Bowes Business Insight's Global Services team. He has over 14 years of experience in professional services as developer, analyst and architect, specializing in the application of GIS technologies for customers across various industries. His background includes experience with a wide range of technologies, methodologies and applications in a variety of operating environments.

Extracting Tangible Value from Smart Grid Initiatives

By Andy Zetlan, Smart Grid Solutions, Telvent
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When implementing Smart Grid technology, there is certainly no shortage of ideas regarding where to begin and how best to realize the benefits. With so many projects occurring at once and with federal Stimulus funds supporting them, the focus has been on job creation and the societal benefits of the Smart Grid, rather than the business case. By contrast, Telvent has worked with utilities around the world to help provide advice and direction to their Smart Grid business case studies, particularly those providing tangible value. That knowledge and background, combined with the experience among utilities that have begun to deploy Smart Grid Solutions, form the basis for this discussion of the business case for Smart Grid and how to extract tangible value from it.

Smart Grid defined

There is no question that the Smart Grid is a broad topic and its definition often varies from region to region. However, in framing this discussion, it is important to define the functions that are included and the relevant sources of benefits. **Figure 1** (below) illustrates an overview of a Smart Grid Solution, the key components of which are shown in orange.

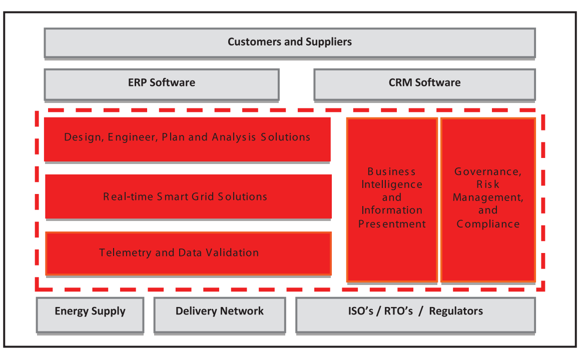

Figure 1: Overview of the Smart Grid Solution

The key functional areas of the Smart Grid include:

- Telemetry and Data Validation: Data from AMI and SCADA networks, along with data from external systems and organizations such as weather forecasts, ISO and RTO communications, energy trading data sources and relevant news.
- Real-time Smart Grid Solutions: Real-time processes such as those contained in SCADA/EMS and other functions that manage real-time events (including outage management, etc.).
- Design, Engineer, Plan and Analyze Solutions: Various systems used to plan, design, and analyze the delivery network. Such analysis can focus on time periods in the past or future, depending on the need.
- Business Intelligence and Information Presentment: Software that can look across multiple types of data to produce the management information needed for smart operation of the delivery network, including the data that demonstrates the tangible benefits of the Smart Grid enterprise.
- Governance, Risk Management, and Compliance: Securing the data and its access to ensure the integrity of information, and providing compliance reporting to demonstrate successful data management.

A Smart Grid Solution uses a wide variety of information systems and telemetry, and interfaces with key "touch points" such as enterprise resource planning (ERP) systems and customer relationship management (CRM) systems that enable the utility organization to function.

The Smart Grid Business Case

Benefits accrue to the organization from four key sources, as seen in **Figure 2**.

- *Financial Improvement:* The improvement of revenues and the lowering or deferral of expenses.

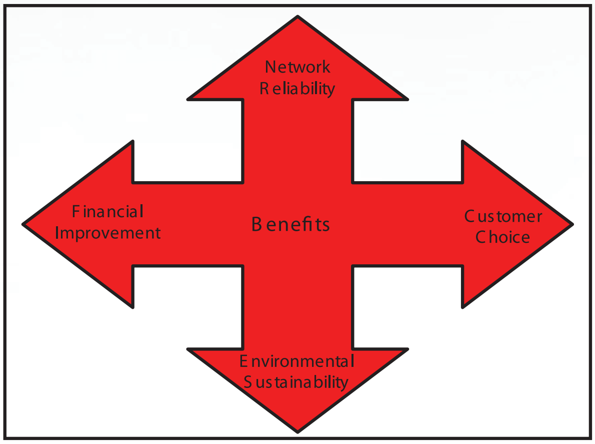

Figure 2: Smart Grid Benefit Sources

- *Network Reliability:* Smart Grid Solutions are all about the energy delivery network and its reliability. Most Smart Grid Solutions focus on the distribution networks, where load growth continues and distributed generation is located. The distribution network is where the action is today and in the near future.

- *Customer Choice:* Smart Grid Solutions enable customer choice by providing data and options regarding energy delivery. Want cheaper rates? Want green energy? Want to help reduce electricity during peak times? Want to see how much the party last night added to the electric bill? Want to sample other rates and see which might be best for you? These and other opportunities await the customer whose utility has implemented a Smart Grid solution.

- *Environmental Sustainability:* Smart Grid Solutions enable utilities to meet environmental obligations and goals through smarter use of resources, helping to use natural resources more efficiently and to support regional regulatory requirements.

Regardless of how tangible the business case, most will contain each of these elements. Further, the business case for Smart Grid should demonstrate tangible benefits – economic and societal – to ensure that the project is worthwhile. The business case should also include the functionality to demonstrate that the value of the Smart Grid Solution is actually achieved.

Tangible Benefits of a Smart Grid

The next few paragraphs explore the types of tangible benefits utilities are actually achieving. For most utilities, only a subset of this list matters and the most relevant items depend on priorities in the individual utility's market.

Financial improvement

Utilities have found that Smart Grid projects can positively impact many areas of financial performance. These include:

- *Identification and reduction of losses:* Most utilities take the reduction of losses into account, whether the losses occur within the network or through theft. Smart Grid Solutions typically help utilities pinpoint operational losses very accurately and can also help identify theft incidents. Both of these instances reduce losses and can also account for varying levels of added revenue, depending on the source of the loss.

- For utilities in parts of the world where losses are significant (e.g., in excess of 10 percent), Smart Grid Solutions should provide more rapid identification of problems and enable effective responses, increasing revenues and lowering losses to reasonable levels. In fact, reduction of losses alone can often overcome a significant portion of costs in the business case for Smart Grid.

- *Reduction in outages and in the time to resolve outages:* Utilities with modern Smart Grid solutions are more aware of issues on their distribution delivery networks and can act to correct those problems prior to an outage. While Smart Grid solutions cannot predict outages caused by other problems (e.g., severe weather), resolution of outages and the ability to more quickly identify faults, isolate them and achieve restoration saves costs and may enhance revenues.

- Reduction in outages and general improvement in reliability varies in need across regions of the globe. The pressure to reduce outages is often less financial than societal and is often required by governments.

- *Enablement of demand response:* Utilities use demand response at the consumer level to save money by reducing peak demand and to make electricity available for more profitable use. Demand response systems, which are generally used in conjunction with customer incentives, enable utilities to have more control at both peak times and as of spot markets change. In fact, many utilities are making this benefit the driving issue in the initial implementation of their Smart Grid Solutions.

- Utilities are generally approaching demand response through the implementation of home devices that can interrupt water heaters, air conditioners and pool pumps, and which can often reset or override temperature settings on thermostats. However, such devices require significant networks and software to operate, which creates a costly system for a much-needed benefit.

- Demand response may also have significant benefits due to the reduced cost of energy production.

- *Enables Distribution System Demand Response (DSDR):* Utilities are approaching DSDR as a key approach to the reduction of peak power and the addition of fast-responding spinning reserve. In a DSDR model, utilities employ voltage reduction to reduce the amount of energy sent to the energy delivery network to satisfy customer need. Often characterized as a broad demand reduction activity, DSDR actually provides a gross reduction of power needed to satisfy demand through changing the voltage via tap-changer at the feeder transformer.

- To achieve the benefits of DSDR, utilities must first establish improved voltage management on key feeders to enable voltage reductions to occur without reaching dangerously low levels. For some utilities this means adding devices such as capacitors in the field to ensure a relatively flat voltage profile across the feeder.

- As an additional step, utilities also can install a large number of low-cost, next-generation RTUs with updated line sensor technology that enables more accurate telemetry of voltage and other data on feeders, which should help the smart grid environment function at peak effectiveness.

- *Reduction of maintenance cost and activity:* Smart Grid Solutions are generally more "self-healing," which means they will react more automatically to changes in demand and supply by switching or turning on key devices as needed. Further, knowledge of possible overload situations and attention to circuit rebalancing will make it possible for feeder infrastructure to last longer without failure. Given the general level of maintenance performed each year, utilities are hoping that the Smart Grid Solutions implemented will lower those costs.

- *Extending asset life:* Utilities are learning to manage an array of asset types more wisely through their Smart Grid Solutions and it is expected that critical assets will be used more appropriately and last longer as a result. This will achieve lower cost overall, as assets will meet or exceed their expected engineering lives in the field. Utilities that are currently underperforming in the maintenance of their distribution systems might, however, see maintenance costs rise due to the awareness and correction of previously unknown problems.

Network Reliability

Utilities, particularly in the United States, already operate energy delivery networks at a very high degree of reliability. Over the past 100 years, engineers have designed a resilient network that has generally performed well.

However, this aging network is facing several challenges: It is beginning to show signs of aging in various places around the country and the introduction of distributed generation and larger demands (e.g., electric cars and their respective charging stations) will cause operational problems that will only increase over time.

Safeguarding network reliability enables the options that reduce cost and support the local economy, creating huge financial and societal impacts. However, in North America, the key to maintaining network reliability can be found in NERC rulings and fines that can ultimately impact the ability of the utility organization to continue its existence. Local government agencies and commissions will struggle with this issue, as new demands and energy supplies arrive on the distribution network, creating new and unstable operating conditions.

Gaining better understanding and control of the distribution network will also enable the economy of the utility's region to grow and adapt to new technologies. The convenience of electric vehicle charging stations, the need for solar energy or wind power centers, and the expansion of our technology-based economy will all be better served with a high-reliability and strong, quality-based network that is more closely monitored and controlled.

Customer Choice

Smart Grid implementations can provide customers with both more choice and more responsibility for the effective use of energy. In the new energy economy, customers will have a larger choice of the pricing of electricity (rate selections) and can adapt to new pricing models as situations change both in supply and demand. Customers expecting a new child, for example, can change their electricity pricing along with the arrival of the baby and their new way of life.

Further, the potential of more real-time pricing exists, which will enable automated devices to respond on behalf of customers to shut down devices and electricity consumption at periods when prices are high. The new Smart Grid Solutions will enable utilities to provide pricing that will include not only the cost of the energy but the price for its transport, including additional pricing for contention on the delivery system during busy times.

Smart Grid Solutions also understand that customers do not fully grasp the complexities of grid management and that there can be contention pricing in one part of the network, even while the rest of the network is fairly contention-free. Similar to broadband carriers of today, utilities will have to pay attention to the management of distribution feeders at a far more detailed level than in the past to ensure that customers see a quality product at a reasonable price.

Customer choice is a significant goal and the building blocks are now being implemented to become the foundation for achieving this benefit. Having customers support demand response and act to improve the power factor can actually reduce utility cost while enhancing the overall network reliability and power quality.

Environmental Sustainability

Lastly, but in many regions the most important benefit, is achieving environmental sustainability. Enabling distributed generation may make electric operations more complex, but it also supports the movement to green power, which is strongly desirable. Postponing a fossil fuel power plant saves a tremendous amount of capital, but it also lowers the carbon and other emissions that are building up in our atmosphere.

Smart Grid Solutions are focused on managing costs, creating customer choice and enhancing network reliability, but not at the expense of the environment. Instead, Smart Grid Solutions are set in place to protect the environment and assure sustainable operation of our utilities.

Obtaining the Benefits of Smart Grid Solutions

With a clearer picture of the benefits, utilities can more clearly understand the approach that is needed for the implementation. Experienced utility customers have strong words of advice for those about to set out on this path:

1. *Understand the Big Picture:* Make certain that the Smart Grid Solutions environment is understood and the path to success is clear, including strong cost/benefit payback and societal impacts. Simply jumping in with a large AMI deployment may be politically expedient but may not bring the needed results.
2. *Go After Low-hanging Fruit:* Achieve your successes early to ensure program support and understanding. Don't wait two years after a huge implementation of meters or other software, but instead fund closer objectives that lead to larger successes later. <u>Build a track record of success by finding early wins and capturing them</u>.
3. *Start with Business Intelligence and Analytics:* Understand your utility's business and the business case for Smart Grid Solutions. Determine which key measures will spell success and then measure them and report on your progress regularly. Fix problems as you see them, but institute an auditing process as the program is created.

Summary

Smart Grid Solutions will be a key part of our lives over the coming decades, and as the world moves to newer paradigms for electricity delivery, customer choice, and sustainable electricity production, Smart Grid Solutions will help get us there. Benefits are clearly there in most regions of the world, but achieving them takes time and attention to the details of which projects to invest in and when. Creation of business intelligence and analytical systems around Smart Grid will provide the needed feedback to utilities, customers and the community as investments are made and results achieved. ■

About the Author

Andy Zetlan currently serves in Smart Grid Solutions at Telvent, providing expertise in the application of technology to smart grid implementations. He has spent his entire 35-year career in the utility industry, working for a utility, for utility industry consultancies, and for technology firms who serve the utility industry. He resides in Mountain View, California.

Volume 2 No. 2

The Bigger Picture

GHG Federal Regulation Is Coming – Even If Climate Change Legislation Is Not

By Gregory K. Lawrence, Partner; McDermott Will & Emery LLP (Contributing Editor)

The planning of the electric power transmission grid, and how it operates, will be profoundly affected by greenhouse gas (GHG) emission control. Whatever happens in Congress with climate change legislation that may (or may not) include a cap-and-trade system for carbon emission credits created by GHG regulation, federal agencies are gearing up for implementation of GHG reduction efforts.

The American Clean Energy and Security Act of 2009 (ACES), which contained cap-and-trade and GHG reduction mechanisms, languishes in the Senate after its narrow House of Representatives approval last June. But the Environmental Protection Agency (EPA), Securities and Exchange Commission (SEC) and Federal Energy Regulatory Commission (FERC) have each launched regulatory initiatives that assume GHG reduction will be enforced. Such enforcement will shift even greater emphasis to renewable energy production – with the transmission grid in the crosshairs.

Uncertainty in Congress

After the House's ACES bill went to the Senate, two Senate committees passed their own climate change bills that contain differing GHG regulation provisions. Despite such differences, the House and Senate proposals share much common ground, including identical mid- and long-term emissions reduction goals, comparable treatment of voluntary reductions and offsets, and similar methods of providing price stability and certainty to market participants. However, action on all three bills has stalled as the Copenhagen conference failed to agree on climate and GHG initiatives to replace the Kyoto Protocol, and as the Senate fixated on health reform legislation. The Obama Administration's 2011 budget proposal added to the uncertainty by dropping the 2010 budget's emphasis on cap-and-trade as a significant source of new government revenue.

It is increasingly unlikely – as the President himself has admitted – that Congress will enact comprehensive energy and climate change legislation in 2010. Instead, members of the House and Senate may try to pass a smaller, simpler and theoretically less controversial bill. Senator Bingaman's renewable energy proposal (which omits cap-and-trade provisions), a streamlined cap-and-trade program similar to the model proposed by Senators Cantwell and Collins, or even a more modest carbon tax could move forward, provided that Congress finds the time to focus on this issue.

Full Speed Ahead at EPA

As Congress waits and debates, the EPA is moving ahead with its own GHG regulatory program. On December 7, 2009, the agency released its finding that current and projected concentrations of emissions combining six GHGs, including carbon dioxide, threaten public health and welfare. The EPA's action responded to the 2007 U.S. Supreme Court decision *Massachusetts v. EPA*, which found that the EPA had the statutory authority to make such a finding. While the endangerment finding itself does not impose any emissions reduction requirements, it sets in motion a series of regulatory events that will lead to federal GHG regulation in various forms unless Congress or the courts intervene.

Most immediately, the EPA is expected to finalize proposed GHG standards for light-duty vehicles that are expected in March 2010.

After the proposed new standards for light-duty vehicles take effect, the EPA will be required to proceed with a proposed rule that requires operating permits and technology based emissions standards for certain stationary sources of GHG emissions. To reduce the administrative burden associated with the new regulations, the EPA has proposed "tailoring" the rule so that it only applies to stationary sources such as power plants, refineries, and medium to large industrial facilities that produce 25,000 tons of GHGs or more per year.

Nevertheless, EPA estimates that at least 3,000 sources could be subject to a new permitting requirement, including many in the energy services industry. The endangerment decision may open the door to other EPA regulations of GHG emissions, whether or not Congress acts on climate change legislation.

EPA's endangerment finding parallels a recent trend of administration activity aimed at curtailing GHG emissions. In late September 2009, the EPA published the Final Mandatory Reporting of Greenhouse Gases Rule, which requires certain facilities and industries to begin collecting GHG emissions data on January 1, 2010, and to begin annual GHG emission reporting by March 31, 2011, for 2010. Similarly, in October 2009, President Obama issued an Executive Order "to make reduction of greenhouse gas emissions a priority for Federal agencies" through energy efficiency, and enhanced monitoring of direct and indirect emissions.

Disclosure Guidance at SEC

Expanded GHG emission reporting and compliance will have significant impact on any company. For those that are publicly held, the SEC on January 27, 2010, released initial interpretive guidance (and followed up February 12 with more details) on existing SEC disclosure requirements relating to climate change, ostensibly to facilitate consistency in disclosure and to enhance clarity to investors. The SEC's interpretative guidance highlighted examples where regulation may trigger disclosure requirements in a company's risk factors, business description, legal proceedings, and management discussion and analysis:

- The extent to which pending or approved climate change laws and regulations, as well as related international accords and treaties, will have a material impact on companies operations or financial performance.
- The new opportunities or risks (including actual or potential indirect consequences) that legal, technological, political and scientific developments regarding climate change may create for companies.
- Evaluation of the material impact that climate change or other environmental matters will have on business performance.

The SEC emphasized that its guidance did not change standard determinations of materiality, and that the agency was not offering an opinion on global warming itself. But commentators have suggested that the guidance signals the SEC intends to scrutinize compliance with existing disclosure rules when considering the adequacy of companies' climate-related disclosures in their SEC filings. The clear implication is that regulation on GHGs and other climate change matters is coming, and companies should prepare to assess and disclose the impact.

Planning at FERC

Connecting these dots, FERC on January 21, 2010 issued a Notice of Inquiry (NOI) seeking public comment on whether to reform any of its rules or procedures as the nation's generation portfolio expands to include more renewable energy resources such as wind, solar or non-storage hydro generating plants. Such expansion is inevitable with the advance of GHG regulation and state and federal renewable energy portfolio standards, and FERC Chairman Jon Wellinghoff's comments on the NOI pointed out that 18,000 MW of renewable energy generation came online in 2008 and 2009 alone.

In an understatement, Chairman Wellinghoff admitted that expanded renewable energy output will "have some operational characteristics which present challenges to system operators. Therefore, it is important that the Commission examine the most efficient ways to effectively integrate these resources into the electric grid, while maintaining reliability and operational stability."

FERC emphasized that the NOI would not immediately change its regulation of the transmission grid. But by singling out possible issues for NOI comments – scheduling flexibility, reliability commitments, reserve products, capacity reforms, curtailment practices – FERC indicated the enormous impact that expanded renewable energy output, spurred by GHG regulation, will have on the grid. Combined with the EPA and SEC actions, the implication is clear: whatever Congress does, now is the time for business to prepare for GHG and climate change regulation. ■

[Jonathan Flynn also contributed to this article and is an associate in the Energy and Commodities Practice Group of global law firm McDermott Will & Emery.]

About the Author

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Enterprise GIS – are we there yet?
Spatially Enabled BI for Utilities

By Aaron Patterson, GM-Engineering
Enspiria Solutions (Greenwood Village, Colorado USA)

Over the past two decades, GIS has emerged from the role of specialist application to be a key part of many utility business processes, from tracking assets and supporting the design process to feeding operational systems such as outage management and capacity planning systems. Some utilities are using GIS to support economic planning work in their state, to maintain right of way information, or to help organize more streamlined inspection and maintenance programs. But is this enough? Have organizations maximized their investment in spatial technology to provide true Enterprise GIS benefits to the organization?

Enterprise GIS exists when users throughout the utility can directly and readily tap spatial data for improved decision-making – Spatial Business Intelligence. Another way of putting it: an Enterprise GIS exists when spatial data is easily and effectively used to clarify, streamline, or improve utility job tasks and business processes across the organization. Traditionally, it has been much easier, for example, to retrieve the number of times a recloser has operated from the company's asset repository database than to create a map highlighting reclosers of a certain type shaded by the number of operations they've performed.

In an Enterprise GIS, the map is just as easy for users to obtain as the asset record itself and users can readily create real business value from this data. Perhaps a user wants to categorize reclosers by type and number of operations since the last inspection event, so the utility can tie in to its predictive maintenance program and create a geographically based inspection program to optimize the inspection teams' route. When a non-GIS user can tap the spatial data to accomplish such an operation, this exemplifies Spatial Business Intelligence from the Enterprise GIS.

Enterprise GIS is an Attainable Goal

There are a number of changes in recent years that allow Enterprise GIS to be a much more attainable goal for a utility. These include:

- End User Adoption of New Technology
- Easier Deployment Options
- The Wide World of Data

End User Adoption of New Technology

Historically, the computing world has been driven by enterprise technology in the workplace. Large organizations with the capital and competition to drive their business forward invested huge sums in cutting edge technology to help them continually improve. This led to advances in computers and systems that ultimately filtered through to the wider population. E-mail is a great example of this – many adults' first e-mail accounts were the ones they used at work – today, most people have at least one personal email account, and oftentimes more.

With the arrival of the Internet, and the increased prevalence of technology in everyday lives, consumer computing has become more of an influence in advancing technology than ever before. From the simplicity of Google's search interface, to the instant and constant ability to connect with anyone, anywhere in the world through Instant Messaging, more and more technology is developed and fine-tuned in the consumer space, and then pushed to the enterprise.

What this shift means for utility enterprise applications is that end-users typically have experience in certain technologies that are being rolled out. In the past, a GIS user interface was a mass of complicated buttons and features that few people had any previous experience with. Today, putting a web mapping application in front of an end-user is a much less daunting experience.

A vast majority of users will have used an online mapping service at home, to get directions to a new restaurant or to find out the sales price of their neighbor's house. This makes for a much more familiar first impression, reducing the ramp up time for each user, and ultimately the cost of deployment for the organization.

Easier Deployment Options

With the advent of technologies such as Citrix and Share-Point, deploying enterprise wide applications is now a much more standardized and attainable mission. Gone are the days of driving to every remote site to ensure the correct software version is installed on a laptop, or having remote support at each work location for when something inevitably went wrong. By centralizing the deployment and running of applications, along with utilizing security access groups that are already set up for everyone in the organization (for example, Microsoft's Active Directory), adding access to additional users for an already deployed application is a relatively trivial exercise. This obviously depends on the computing capacity being in place to support the additional users, yet as computing power increases and hardware and storage costs continue to fall, the infrastructure costs for projects are continuing to drop.

In addition, web based GIS applications are quickly catching up to their desktop counterparts in terms of the power and functionality available. The holy grail of web mapping, editing, is now attainable using the latest software releases from a number of vendors, and the exposure of much functionality via APIs and web services mean that the majority of tasks previously only available via the large footprint desktop applications can now be pushed out to users via a web interface. Access to information on network improvement that is in progress, either in the design or build-out phase was often just accessible by the engineers and the CAD or GIS operators working on that specific job. Now utilities can publish in-progress jobs to the enterprise via a GIS web view as an integral part of their workflow with relative ease.

The Wide World of Data

In recent years, a key area of GIS expansion has been more open access to a variety of data sources. In the past, the only spatial data available was the data created and maintained internally by the organization. The concept of sharing data sources, or accessing other organizations data sources, although interesting, was not really available to any great degree, outside of some government land base data that was often of little practical use for managing an electric network dataset. However, changes in both the attitude of organizations to sharing data, along with various technological advances in the ability to serve up data on an as-needed basis have resulted in new opportunities for organizations to pull in both internal and external data that can be useful to their business.

Previously, interesting and useful data had to be loaded internally to a GIS database prior to being able to be used effectively to support decision-making. This is no longer the case. Accessing data services, such as real-time weather feeds, demographic data, or "street view" photography is now widely available from various vendors, opening up a whole new set of questions that can be answered by the GIS. In addition, the fact that this data is accessed "live" allows for vendors to refresh whole datasets and make those available to their customers without the distribution issues of the past, where CDs or hard drives had to be shipped out.

This is especially pertinent in emergency situations such as hurricanes, where often times updated satellite imagery is available in a relatively short period of time, allowing a high level view of storm damage to the utility operations center.

When these changes in behavior and advances in technology are tapped to extend GIS functionality across the enterprise, utilities gain measurable benefits. Extending the use of spatial data into other parts of the utility organization that don't traditionally use GIS is a key step along the way toward achieving Enterprise GIS. The following describes two areas in which utilities are using Spatial Business Intelligence to improve their decision making, expanding both their GIS user base and GIS data: Outage Communication & Planning, and Advanced Metering Infrastructure (AMI) Deployment Planning.

Outage Communication & Planning

A critical area for every electric utility is their performance in response to a major outage event. Ensuring safety, maintaining critical customers and returning power as quickly as possible are all key goals for a utility.

Where are the network issues? Where are my crews? How long before the storm moves out of my service territory? How long before I get the right equipment to the right location? These are just some examples of the questions that need to be answered to solve the multitude of problems a large-scale outage creates. And the availability of relevant and timely information, tailored to specific groups of users, can make the difference between hitting targets for restoration, or not.

Under the concept of Enterprise GIS, utility users can directly and readily tap spatial data for improved outage processes and decision making, in real time as the storm is taking place and/or after the outage to improve performance for the next time. By overlaying near real-time outage information over the utility's network data, and allowing end users to view both high level and detailed information as it comes in, utilities can address issues from a more proactive level as the outage develops.

Data to support this decision making process comes from various systems, including the outage management, work management and mobile workforce management systems internally, along with weather feed information externally. This data was never previously integrated with other spatial data sources, despite often having some spatial component or tie-in that can be used, be it zip code, address, or network name for example. GIS applications can use this spatial component to geocode incoming data "on the fly" for visual display.

By deploying the outage communications and planning capabilities on a web based Intranet infrastructure, critical event data can be communicated more effectively to more of the organization during stressful outage responses. This is especially useful to get answers as they relate to the overall picture of a particular outage – for example:

- Did the volume of customer calls increase or decrease in the last hour?
- Are particular counties being worse hit than others, and do I have the right crew balance)to address this?
- Are all of my wire-down situations correctly staffed?

Sample Outage Dashboard with Thematic Charting by Circuit

A key aspect to capturing this data is the ability to take a temporal view, and actually replay specific major events at some point in the future as if they were happening live. This capability allows users to be trained using actual historical storm data from a past event, as well as a providing the platform to review a utility's performance in the cold light of day, helping to improve standard operating procedures before the next event arrives.

Tapping Enterprise GIS capabilities for outage communications and planning bring a number of benefits to the utility, including:

- Better tactical information with which to make restoration decisions,
- Providing outage information to a wider set of decision makers/users,
- Improved communications with consumers and other external parties,
- Providing a systematic way of analyzing the data after the storm is complete,
- Making better strategic and planning decisions to prepare for the next event, and
- Providing training opportunities for both new and experienced staff.

AMI Deployment Planning

Deploying advanced meters is a major component of most major Smart Grid projects, providing the fundamental communication from the customer to the utility in "near" real-time. Meters, and the communication networks to support them, are the major cost component in a project of this type. Utilities are now able to use Enterprise GIS functionality to optimize meter deployment, providing positive impacts on the overall Smart Grid Business Case. Utilities can optimally develop their deployment strategy based on, for example, geography, hard to access accounts, age of infrastructure, demographics, meter/regulator types, political considerations, and cost to serve.

Enterprise GIS functionality and the associated spatial intelligence can be tapped for AMI deployment planning including for...

- Technology Optimization – The determination of meter density mapping across the service territory.

- Initial Deployment Area Selection – Mapping meter density across the service territory AND mapping of multiple attributes to identify optimal potential initial deployment locations. This is useful during an initial field trial or pilot phase to plan installation of meters across a wide selection of customer types and physical locations while also taking into account such things as socio-economic factors.

- Full Deployment Sequencing – Mapping meter density across the service territory AND mapping multiple weighted benefits attributes to identify a deployment sequence that will maximize Return on Investment (ROI).

By identifying specific endpoint characteristics and their physical locations within a utility's service territory, potential benefit groupings can be identified. Using the GIS, combined with available datasets, both internal and external, areas and locations of highest potential benefits can be identified and targeted for early deployment. Some examples of benefits and corresponding data utilized in analysis include:

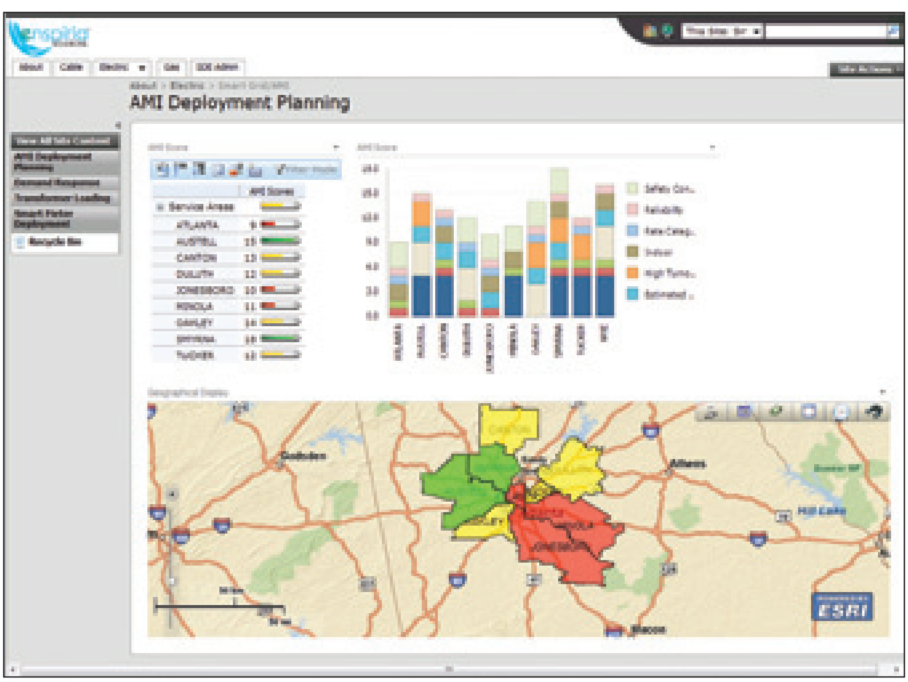
- Meter Reading Cost Reduction – Hard to access meters, high turnover, high number of billing complaints/disputes, inside meters
- Density – Urban, suburban, rural, multi-units
- Revenue Protection – Endpoints with collection problems, high turnover, distressed areas, history of tampering

This capability allows the utility to target selected populations for technology deployment. Benefits gained from this use of Enterprise GIS include:

- For pilot testing, the ability to identify a geographic area that represents the desired technical challenges and potential benefits
- Facilitating identification of customers with the potential to deliver benefits in excess of the general population.
- Maximizing a utility's ROI by providing higher performing benefits early in the deployment cycle

In Summary

Although GIS has entered the mainstream at many utilities and is becoming an increasingly critical part of the information infrastructure, continuing developments in end-user adoption, technology and data have allowed progressive organizations to continue to expand the role of Spatial Business Intelligence in the decision making process. Continuing to look for opportunities to utilize spatial data and your Enterprise GIS in new ways will offer continuing progress in the never ending drive for more efficient and effective business intelligence and decision making. ■



AMI Deployment Planning Dashboard for Initial Deployment Selection

About the Author

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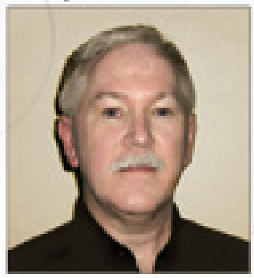

SECURITY SESSIONS

Volume 2 No. 3

With William T. (Tim) Shaw, PhD, CISSP

Hey, who do you think you're talking to?

Not too long ago I had the opportunity to engage with a number of utilities struggling to attain full compliance with the NERC CIP standards. Part of that involvement included visiting their generating facilities and looking over the way they were protecting their critical plant systems. It also included reviewing the security for their EMS/SCADA systems. The effort invariably involved dealing with plant and corporate IT personnel because the evolution of automation systems – particularly over the past decade – has blurred the distinction between those systems and what we think of as 'business' systems. This could be a good thing or a bad thing, depending on how far it goes. This column will discuss the impact of these 'hybridized' automation systems on security and the fact that when it comes to networks, sometimes you really don't know who you're talking to... – ***Tim***

From a historical perspective, the development of computer-based automation is somewhat separate from that of the development of computer-based technology for general business applications. These two markets may have indeed shared some hardware platforms, but the computer suppliers involved did not offer the specialized real-time networking, I/O hardware, software or HMI technologies needed to create control systems at the time. Thus, DCS and SCADA vendors either developed their own tools internally or cobbled together bits and pieces of whatever they could find to create solutions.

For that reason, a person learning "IT" – Information Technology, that is – would not have been familiar with much of the technology in a computer-based automation system. But considering the eventual domination of Intel and Microsoft and the widespread adoption of Ethernet and TCP/IP networking in the control world, today's DCS and SCADA systems look a lot like business systems. And, because of that transition, today even a traditional IT person would be quite familiar with much of the underlying technology.

That is both a blessing and a curse. A very significant reason why our current automation systems are vulnerable to cyber attack is because they incorporate such a large amount of conventional IT/business technology. Moreover, IT people in more and more organizations are being called upon to support automation systems as a cost savings measure. This is perhaps more prevalent with SCADA systems than with DCS systems so far, but contemporary IT philosophies and strategies are making their way into both environments.

SECURITY SESSIONS

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IT organizations are used to creating fully interconnected and integrated corporate networks, where it is possible to access any system or computer from anywhere on that network, and where centralized servers and support are the most efficient way of performing their mission and provide rapid response to problems. As one would expect, they (IT personnel) would tend to promote those same strategies when asked to support other, seemingly similar, computer-based systems. Both DCS and SCADA systems of any recent vintage – certainly those installed and commissioned within the last decade – will have undergone some amount of "hybridization" with traditional IT systems.

During the past year I've had the opportunity to closely study a few systems where corporate IT had exerted significant influence over their evolution, which yielded some rather interesting observations. For example, an application engineer or process engineer sitting down at a system workstation for either type of automation system (i.e., SCADA or DCS), used to "log in" and have his/her usage rights validated (or rejected) directly by that system. But in a highly hybridized system, those same engineers may have their user login passed over a corporate network to – and validated by – a centralized corporate authentication server, such as a Microsoft Active Directory server that is managed by the IT department.

This is very convenient because it allows a single repository for user access rights information and credentials across all corporate systems. If the automation systems incorporate MS-Windows workstations or MS-Windows- or Linux-based servers, it is quite possible that those computers are being patched and having their virus scanning software updated from another corporate server that is being managed by the IT department. These automation systems may also receive time synchronization from a corporate network time-server, and they may depend on yet another corporate Domain Name Server (DNS) to be able to locate other systems within the corporate network with which communication is required.

These various corporate servers may be physically located in the same plant facility, corporate facility or, they could physically be anywhere else on the corporate network, since many organizations have linked their corporate networks and plant/system networks together. The result is very convenient, very efficient and very much in line with accepted IT strategies. But from a cyber security perspective – and especially a NERC CIP perspective – this is also very problematic.

NERC-CIP requirements call for special protections, both physical and electronic, to be applied to critical systems, which are included under NERC's "critical cyber assets" terminology. But when a critical system has some functional dependence on other systems (i.e., systems that may or may not be afforded the same level of security), the critical system has been inherently – and perhaps seriously – compromised with additional, exploitable vulnerabilities. That is, if communications between automation systems and such servers traverse corporate networks without suitable communication protections, they are implicitly vulnerable to any number of network-based cyber attacks. Not only can message traffic can be intercepted, falsified or blocked, but if these servers are attacked and disabled, the functions they provide will be unavailable to the critical systems unless some level of redundancy or backup is provided.

NERC CIP standards take a somewhat conventional view of SCADA/EMS systems and also plant automation systems. The conceptual model is of stand-alone, (mostly) autonomous systems, with a small number of data exchange interconnections that might be – but probably aren't – critical to the essential functioning of the system. But, through hybridization with corporate IT systems, a modern SCADA/EMS or plant DCS system might rely on one or more distributed servers scattered around an insecure corporate communications infrastructure. This makes it very difficult to establish and protect an electronic security perimeter (ESP).

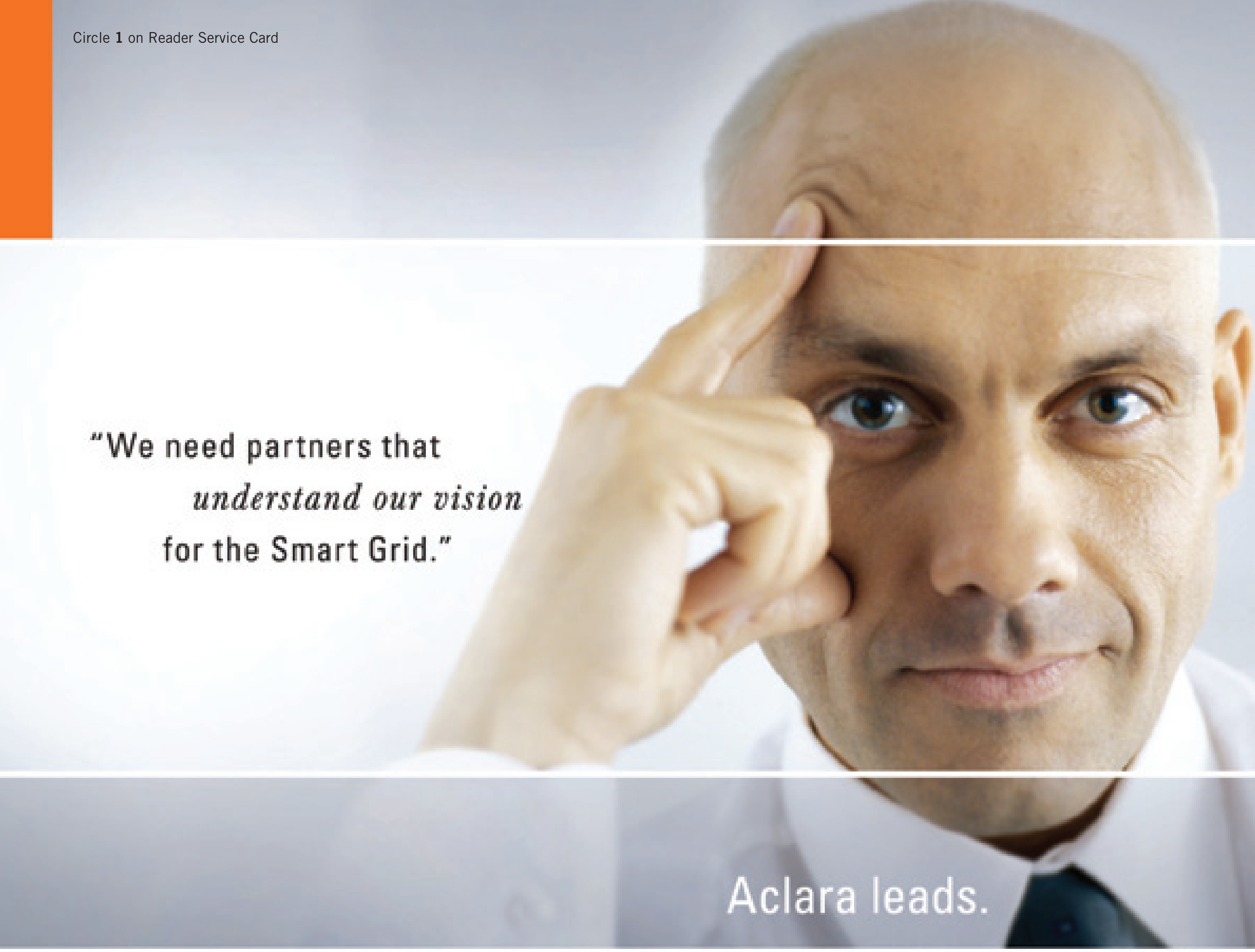
The NERC CIP concept of protecting access points through the ESP is based on the assumption of an attacker trying to gain access to the critical system or infect it with malware through the access points. But with highly hybridized systems, an attacker need not attempt to reach the critical system at all. When corporate IT systems become essential to a critical system, one would simply attack the corporate system(s), which frequently would not have the same level of security protection as the critical system. Of course, a utility could solve this problem by declaring all of the various corporate servers as being within and ESP and PSP (physical security perimeter) and giving them all of the security controls outlined in the CIP standards. Notably, this would mean appropriately monitoring and defending each of the access points – every one of those connections to the entire corporate network, which could be exceedingly complex to say nothing of the time and cost issues.

The obvious solution to these problems is actually quite simple: Move those distributed functions back into the critical systems themselves. In other words, return them to the stand-alone, autonomous model envisioned by NERC. Most DCS and SCADA systems already have the ability to support those functions, even if it means adding another computing platform within the ESP. This makes supporting those systems less convenient, but eliminates a very severe and potentially dangerous (yet largely invisible) set of vulnerabilities.

Don't misunderstand my point here; IT people have a lot to teach SCADA and DCS system engineering and support personnel about cyber security and network protection. And unfortunately, we can't simply turn back the clock to the days before plant-to-boardroom network connectivity. But there remains a basic difference between 'best-practice' policies and procedures for IT and those for industrial automation. In general, it really boils down to addressing safety issues and the very different consequences between having an IT server compromised and having a SCADA/EMS or plant DCS system compromised. Clearly, there needs to be an ongoing dialog and knowledge exchange by and between these departments and disciplines, but that will have to be the subject of a future column... ■ – ***Tim***

About the Author

William T. "Tim" Shaw (PhD, CISSP) has been active in industrial automation for more than 30 years and is the author of Computer Control of BATCH Processes and CYBERSECURITY for SCADA Systems. Tim has contributed to several other books and is a prolific writer and presenter on a range of technical topics. He is currently a senior security consultant for Securi-Con, an information security solutions firm, based in Alexandria, Virginia. Tim has been directly involved in the development of several DCS and SCADA system products and regularly teaches courses for ISA (International Society of Automation) on various topics. Inquiries or comments about this column may be directed to Tim at *Tim@electricenergyonline.com*.


Circle 1 on Reader Service Card
"We need partners that
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for the Smart Grid."
Aclara leads.