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Bulk System Reliability Assessment and the Smart Grid


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Electric Energy T&D MAGAZINE

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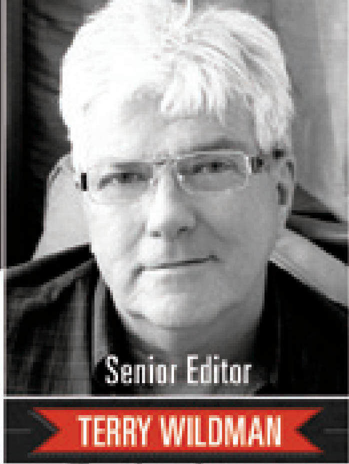

POWERPOINTS

Greenland gets greener

A friend very recently asked me if there was just one place on the planet I would love to go back to. Without hesitation, I said Greenland. He thought I was joking but when I started to explain my answer, he began to understand.

I worked for an aircraft manufacturer who sold fixed-wing planes to Greenland's national airline. I was given the opportunity of a lifetime to travel to the largest island on the globe to document in words and pictures the life of the people and the impact the airline and 'our' airplanes had on their lives. It is the least densely populated country in the world and most of the fifty-seven thousand people live in small communities along the fjords on the west coast including Godthåb, the capital. A large number of the communities are accessible only by boat or plane during the summer and by plane – weather permitting – or dog team in the winter.

I was there in January and for several weeks travelled the length and breadth of this remarkable land – always in the jump seat between the helicopter and fixed wing pilots. One of the things I found fascinating is how people coped in the self-contained environment of Greenland's villages and communities. Each town generates its own energy and distributes it through a micro-power grid and local district heating network. For many years the joy was generated by power plants made from old ship engines running on diesel, every drop of which had to be imported. I remember seeing U.S. Air National Guard LC-130 *Hercules* heavy lifters flying in huge bladders full of fuel to replenish supply depots at Søndre Strømfjord the major airport on the west coast. I was told in English the name translates as 'the great (or long) fjord.' It's no secret that the downside of burning fossil fuels is pollution and in this case, it is the biggest single contributor to the country's greenhouse gas emissions.

I learned that the country has been replacing its diesel power machines with hydropower plants. Incredulous at first I started asking questions and researching how this could be done. Greenland has vast resources of glacial melt water that is being used to generate lower cost hydropower. The latest installation is a 22.5 megawatt plant comprising three 7.5 megawatt turbines for the town of Ilulissat, the third largest community in Greenland and the iceberg capital of the northern hemisphere. I was immediately reminded that the townspeople would enjoy the clean, renewable energy and so too would the local district heating network. This power plant is unmanned and located in an isolated fjord 45 kilometres from Ilulissat and is built into the permafrost 200 metres beneath the ice cap. Melt water is then channelled through the permafrost to spin turbines, which feed the power to lines that carry the clean power 50 kilometres to the town. Apparently the site is so remote that if a fault were to occur during the harsh winter storms it could take weeks to reach the plant for repairs. In that case, the old diesel genny would have to be put back into action.

The plant produces enough hydropower to supply more than 16,000 households and the new power saves about 23,000 tonnes of CO_2. I also learned that this is the third complete power and automation system in Greenland's ongoing conversion to renewables. These, combined with other hydropower projects, provide almost 70 percent of the county's electricity.

The town of Ilulissat sits across the water from Disko Island and overlooks the mouth of the Ilulissat Icefjord or in Geenlandic, Kangia, which is 40 kilometres long and seven kilometres wide in places. It's just under halfway up the west coast some 300 kilometres north of the Arctic Circle, and is part of the Disko Bay tourist region. Its particular notoriety is the location itself. Called the Sermeq Kullajeq glacier, which means southern glacier, it travels about 40 metres each day and spawns around 45 cubic kilometres of 'calf ice' each year. It is here that the world's fastest moving glacier calves many of the huge icebergs that languish for a couple of years in Baffin Bay slowly drifting into Davis Strait and finally entering Iceberg Alley. With over 700 metres visible above the water, which as we all know represents only about ten percent of their size, mammoth bergs can seriously threaten shipping in the North Atlantic and oilrigs off Newfoundland more than 2900 kilometres to the south on their way to a certain end in the moderate waters off the U.S. east coast. It was one of their ancestors that sent the great White Star liner *Titanic* to her death in 1912.

As for Greenland's drive for clean energy, I take off my hat to them. I have witnessed how primitive life can be and was privileged to have the best seat in the house through the windscreen of a helicopter to watch a dozen or more men working in unison, as they had done for thousands of years, to harpoon a whale. Working from their small boats surrounding the creature in a sea of red froth was a sight I shall never forget. That whale fed and kept oil lights on for many people over the frigid, near dark conditions that still lay ahead. As we flew up the coast just off the deck, I saw several women cutting up a whale carcass and filling wooden boxes with the meat. One of our drivers said the animal could have beached itself or died and was washed up onto the shore. It too would be a welcome find for the community and every member would receive a share.

Today, as we move into a new year, I thought of the disconnect of the scenes that had unfolded before me in this tough, yet giving land. I wondered how many of the people I saw had any idea their land and their time was entering an era of clean, renewable power destined one day to land on their very doorstep.

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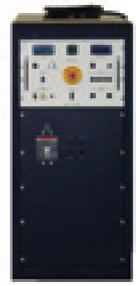

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INDUSTRY NEWS

SaskPower Selects Quanta Services to Install Island Falls to Key Lake Transmission Line

Houston, TX, January 2013 - Quanta Services, Inc. (NYSE: PWR) announced that SaskPower has selected Valard Construction, a Quanta Services company, to install transmission infrastructure for the Island Falls to Key Lake Transmission Line Project. Under the terms of the contract, Valard will build approximately 186 miles (300 kilometers) of 230-kilovolt transmission line in northern Saskatchewan. The project scope includes foundation construction, installation of approximately 900 transmission towers, wire stringing and related project management.

"Growing economic development in northern Saskatchewan has created an increased need for power. SaskPower is investing in its electricity system to ensure it meets the power needs for our region, today and in the future," said Robert Watson, president and chief executive officer of SaskPower.

To minimize environmental impact, the route of the new transmission line will parallel an existing SaskPower transmission line. Valard has initiated engineering activities and the project is expected to be complete in the spring of 2015. Once in service, the new transmission line should increase reliability and provide infrastructure to meet the growing demand for power in northern Saskatchewan.

"Valard enjoys a strong working relationship with SaskPower, and we are eager to leverage our knowledge of the region, experience and resources on another initiative to strengthen the region's electric power infrastructure," said Jim O'Neil, president and chief executive officer of Quanta Services. "With the largest highly skilled and mobile power infrastructure workforce in Canada, we anticipate another safe and successful project."

"Valard opened a corporate office in Saskatoon last year as part of our ongoing commitment to Saskatchewan," said Adam Budzinski, president of Valard. "We look forward to constructing the Island Falls to Key Lake project and participating in the exciting growth of the province."

For more information, visit *www.saskpower.com / www.valard.com / www.quantaservices.com.*

PNM Receives FERC Approval for Transmission Rate Case Settlement

Albuquerque, NM, January, 2013 - PNM Resources' (NYSE: PNM) New Mexico utility, PNM, received approval from the Federal Energy Regulatory Commission (FERC) for an unopposed transmission rate case settlement that was filed July 3, 2012. The $2.9 million rate increase does not impact retail rates for New Mexico residential or business customers.

PNM originally filed for a transmission rate increase in October 2010. As permitted by FERC rules, in June 2011 PNM began billing at the higher rates associated with the original filing subject to refund.

The agreement is a "black-box settlement," meaning the parties agreed to a specific revenue number but no specific return on equity. The settlement parties also agreed not to oppose the concept of a formula-based transmission rate filing. The company made that formula-based transmission rate filing on Monday, Dec. 31, 2012.

"We are pleased that our settlement agreement was approved. This approval, together with our current efforts to move ahead with a formula-based transmission rate filing, are important steps in improving the alignment of wholesale transmission costs and revenues," said Pat Collawn, PNM Resources chairman, president and CEO.

Worldwide Electric Vehicle Sales to Reach 3.8 Million Annually by 2020, Forecasts Pike Research

Boulder, CO, January, 2013 - Since the launch of the Nissan Leaf and Chevrolet Volt, in late 2010, plug-in electric vehicles (PEVs) have become more widely available in Asia Pacific, North America, and Western Europe. Hybrid electric vehicles (HEVs), which first appeared a decade earlier, are now selling steadily in those regions as well. According to a new report from Pike Research, a part of Navigant's Energy Practice, annual worldwide sales of these vehicles, collectively referred to as electric vehicles (EVs), will reach 3.8 million by 2020.

"Sales of EVs have not lived up to automakers' expectations and politicians' proclamations, but the market is expanding steadily as fuel prices remain high and consumers increasingly seek alternatives to internal combustion engines," says senior research analyst Dave Hurst. "Indeed, sales of plug-in EVs will grow at a compound annual growth rate of nearly 40 percent over the remainder of the decade, while the overall auto market will expand by only two percent a year."

The PEV sector can be split into two vehicle categories, plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs). According to the report, the number of PHEVs sold in most regions is expected to be lower than BEVs, except for North America and Latin America. In these regions, the longer driving range of PHEVs is expected to prove more attractive to consumers. In other regions, the high cost of petroleum fuels, large number of BEVs available, and dense urban areas are anticipated to contribute to higher sales of BEVs than PHEVs.

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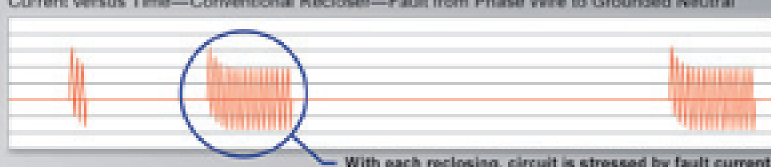
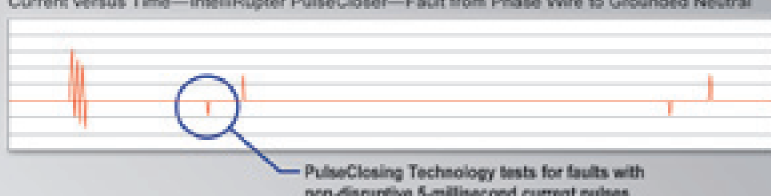
Current versus Time—Conventional Recloser—Fault from Phase Wire to Grounded Neutral



Current versus Time—IntelliRupter PulseCloser—Fault from Phase Wire to Grounded Neutral



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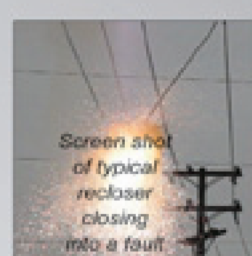

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INDUSTRY NEWS

Top 6 Things to Get Right in 2013 for Consumers and Smart Grid

Smart Grid Consumer Collaborative shares key research insights to guide the way

Atlanta, GA, January, 2013 - Surveys show: the opportunity is ripe in 2013 for consumer outreach and education about the value and benefits a smart grid can bring. Throughout 2012, the Smart Grid Consumer Collaborative conducted a series of statistically valid surveys and in-depth interviews with consumers about their thoughts, feelings, values, attitudes and opinions of smart grid and its potential benefits.

"In summary, we've found that once consumers are educated about smart grid, they are supportive of it," said SGCC Executive Director Patty Durand. "So the opportunity to further engage with our consumers only gets bigger. Armed with research, facts, figures, knowledge and a vision, industry can continue to educate its customers."

Durand noted SGCC's recent infographic quantifies some of the everyday benefits consumers could see from a fully-realized smart grid.

Below are a summary of the primary insights about consumers, gleaned from SGCC's research efforts this year:

- Many non-financial benefits of smart grid upgrades are as compelling to consumers as those that can save consumers money, according to second-wave findings of the SGCC Consumer Pulse Study. Survey participants were asked to rate the importance of seven potential benefits of smart grid and smart meters, including ease of connecting renewable energy sources to the electric grid and reduced outages, among others. Critically, each benefit was found to be important to 80% or more of respondents.
- Consumers see some smart grid benefits that they consider to be worth paying more for – such as outage restoration after storms like Hurricane Sandy. Customers were most willing to pay for improved reliability and restoration, increased access to renewable energy, availability of better usage information and new pricing options and reduced environmental impacts, according to SGCC's Consumer Voices report.
- More than half of consumers found time of use pricing and peak time rebates appealing. Those who indicated they were likely to participate cited both an interest in saving money and a more altruistic motive, such as helping the environment or helping to prevent an outage in their community, according to SGCC's Consumer Voices report.
- The better they understand it, the more consumers support smart grid and smart meters. After being provided with introductory information about smart grid and smart meters, participants generally described their overall feelings toward the new technologies as favorable or very favorable, according to SGCC's Consumer Voices report.
- Low income energy consumers are less aware of electricity grid modernization technology than the general population but they find its benefits compelling nonetheless, concluded the Spotlight on Low Income Consumers survey conducted by SGCC.
- Consumers are interested in various smart grid-enabled pricing programs and services and are increasingly likely to use social media to access energy information, according to SGCC's Consumer Pulse Survey Wave 3. The survey results also indicated that consumer awareness of smart grid has remained relatively consistent during 2012, with 54% of Wave 3 respondents never having heard the term "smart grid."

Executive Management Changes Announced at Southern Company

Atlanta, GA, January, 2013 - Southern Company Chief Financial Officer Art P. Beattie announced several changes within the company's financial management team, effective March 31.

Ann P. Daiss will become chief accounting officer and comptroller of Southern Company, as well as senior vice president and comptroller of Southern Company Services. Daiss is currently vice president, comptroller and chief accounting officer for Georgia Power.

Daiss will replace W. Ron Hinson, who will become executive vice president, chief financial officer, treasurer and comptroller of Georgia Power, the largest subsidiary of Southern Company, serving 2.4 million customers in all but four of Georgia's 159 counties. Hinson will assume the role vacated by Ronnie R. Labrato, who has announced plans to retire.

"Southern Company's long-term success is a direct result of our commitment to identifying and developing leaders," said Beattie. "Ann and Ron have consistently demonstrated effective leadership, and I am confident they will continue to excel in their new roles."

Daiss, 45, joined Southern Company Services in 1998 as director of accounting. In her current role, which she assumed in 2006, Daiss is directly responsible for all internal and external accounting and reporting, as well as Georgia Power's rate case regulatory strategy. Her previous job duties included responsibility for the consolidated financial reporting and Securities and Exchange Commission reporting for Southern Company and its registrant utility subsidiaries. Prior to joining Southern Company, Daiss was a senior audit manager for Arthur Andersen's Atlanta office, where she served clients in the utility, airline and investment management industries.

Hinson, 56, joined Georgia Power in 1979 as an accounting associate. During his 27 years with Georgia Power, Hinson held numerous positions in the corporate accounting organization, including serving as vice president and comptroller, and was an active participant in state regulatory activities. He was elected to his current position with Southern Company in 2006.

INDUSTRY NEWS

Aclara Acquires Cellular Solutions Business to Enhance TWACS Power-Line Communications Technology for Advanced Metering Infrastructure

St. Louis, MO, January, 2013 - Aclara, a leading provider of intelligent infrastructure solutions and a member of the utility solutions group of ESCO Technologies Inc. (NYSE: ESE), has acquired the assets of Metrum Technologies LLC of Waco, Texas. Metrum is a leading provider of wireless public network communications products for electric utilities as well as hosted software systems and network operations for its solutions. Metrum's research and development center located in Dallas will also become part of Aclara. Terms were not disclosed.

Aclara initially will deploy Metrum's patented, internet-protocol (IP)-based solutions to enhance Aclara's TWACS technology in rural electric cooperative and municipals, providing a high-availability, high-bandwidth, low-latency communications channel.The technology also provides for high-density meter deployments as well as demand response, distribution automation, SCADA and commercial and industrial applications. Metrum's technology is already deployed at 350 utilities throughout the United States.

"Metrum's communication technologies are an excellent complement to Aclara's network offering," said Brad Kitterman, President, Aclara. "Adding Metrum's portfolio of products to our existing offerings allows Aclara to provide a more comprehensive solution that will enable our existing customers – as well as new ones – to optimize the economics of their smart grid deployment by balancing bandwidth requirements with cost."

Aclara's acquisition acknowledges a trend by utilities to deploy cellular solutions using existing public networks. Market research firm Pike Research, in fact, has forecasted cellular communications will grow by 20 percent in the smart grid market by 2016.

"Aclara has an outstanding reputation for providing exceptional smart grid solutions to all three utility segments," said Steve Swenke, Chief Executive Officer of Metrum. "I believe the combination of Metrum's and Aclara's technology platforms will enable a best-in-class offering of cellular, RF and power-line communications technologies for our utility customers."

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

How New 'Smarter' Technologies in the Smart Grid got the Lights Back on Faster Following Superstorm Sandy

We are speaking with John D. McDonald, director, technical strategy and policy development at GE - Digital Energy.

EET&D: What smart grid upgrades would aid in power outage management during disasters such as Sandy?

McDonald: First and foremost, the improvement that utilities must consider is their communications infrastructure. This is the foundation of the grid, as it must be robust enough to support the technologies that are overlaid on top of it.

There are three different facets of the communications infrastructure that utilities should focus on:

1. Response requirements: These ensure that the communications infrastructure can support the smart grid applications' response needs in a matter of seconds, minutes or hours.
2. Bandwidth: Applications send data back and forth, and the infrastructure must be robust enough to support the smart grid applications' data flow requirements.
3. Latency: The delay in communications that the grid infrastructure can tolerate must be satisfactory to the application.

EET&D: When analyzing the smart grid during a disaster, what component do you consider to be the most important, and why?

McDonald: It's difficult to pinpoint a single component of the smart grid that is most important, as the integration of all of the separate components (smart meters, AMI, GIS, OMS and DMS) is key when dealing with disasters such as Superstorm Sandy. However, there is a critical part of a utility's system – the distribution area – or the part of the grid that brings electricity to the customer. The distribution area has historically had the least investment in added technology, which makes it extremely difficult for utilities to detect disturbances. There are 48,000 distribution substations in the U.S., and less than half have any monitoring at all. As smart grid modernization continues, there needs to be an increased focus on the distribution system – and more investment in monitoring and control is critical to more effectively manage power outages during extreme cases such as Sandy.

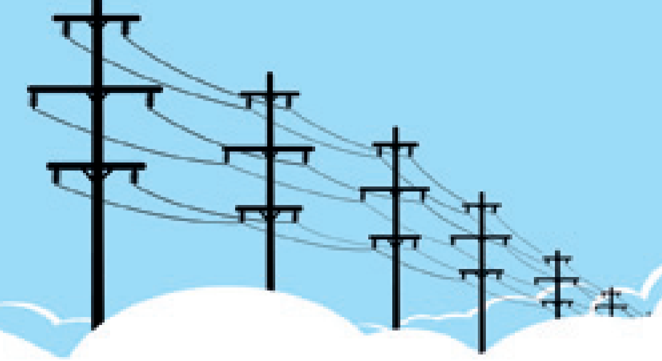
EET&D: What are 'last gasp' and self-healing technologies, and how could they benefit utilities and consumers?

McDonald: The 'last gasp' capability is one that GE has built into smart meter technology. As long as electricity is on, a smart meter can perform its functions and communicate with a utility. When power is lost, ideally the meter would send a signal indicating lost power to the utility. As more than half of the 48,000 distribution substations in the U.S. are without any sort of monitoring capability, there is no way for utilities to tell when power is lost, unless consumers call the utility, which may take hours if it even happens at all. To solve this issue, GE has equipped its smart meters with a stored energy device, called a capacitor, which is charged as long as the meter has electricity. When power is lost, the capacitor has enough charge to allow one 'last gasp' communication that travels upstream to the utility indicating a loss of power. This enables utilities to realize which customers are without power, which is a critical first step in mitigating the outage, and also activates self-healing smart grid applications that will restore power to the healthy sections of the grid as quickly as possible.

A typical self-healing technology that's implemented into distribution systems is a smart grid application called fault detection isolation restoration (FDIR), which detects when there is a fault in the distribution system. The last gasp from the meters informs utilities which customers are without power, while the FDIR application will sense the problem on the distribution line and identify the location, isolate the faulted section by sectionalizing on either side of the disturbance, and restore service to the healthy parts of the grid as quickly as possible, both upstream and downstream from the faulted segment. The utility then sends a crew out to look at the faulted section of feeder, perform any needed repair and bring power back on to faulted segment. The self-healing power aspect of these technologies is that they run "closed loop", meaning no human is involved. The system essentially heals itself, and because no human is in the loop, it can perform its restoration very quickly.

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid



EET&D: Could you provide an example in which the smart grid actually provided outage management during Sandy?

McDonald: The Rockefeller Center, or '30 Rock' building, never lost power during Superstorm Sandy. When designing 30 Rock, the planner kept natural disasters and other unpredictable incidents in mind. GE engineers were involved in the design of 30 Rock's electrical system and installed an uninterruptible power system (UPS), a series of batteries and a diesel generator to ensure power would never be lost. In the case of Sandy, when 30 Rock lost power from the local grid, the UPS and batteries kept power on to the critical loads that were deemed important enough to remain energized during an external outage.

When power outages occur in a massive building such as 30 Rock, the electrical system's voltage will fluctuate more wildly than it would under normal conditions, because as load is lost and the system is fluctuating, the voltage decreases and oscillates. To keep the electricity on, loads require a constant voltage. A UPS provides constant output voltage, regardless of how much voltage is varying in the input. The installed batteries are sized to withstand multiple hours of power outages, and while the batteries are feeding critical loads, the diesel generator starts automatically. Once synchronized with the electrical system, the diesel generator will take over for the batteries, as the generator can supply power to a facility for as long as there is fuel available. Hospitals, airports, casinos and other "mission critical" facilities where reliability is extremely important utilize these technologies.

EET&D: Can you outline the specific technologies that make up an integrated smart grid system?

McDonald: If a utility invests in the following four technologies and integrates them in the correct manner, it will be fully prepared for a disturbance, both in proactive preparation and the ability to restore the system following a disturbance.

1. AMI (Advanced Metering Infrastructure): The AMI is a solution in the communications infrastructure that is comprised of a two-way communications system and used in conjunction with smart-metering. This system allows utilities to gauge electricity usage from the meters themselves, while also providing voltage and outage information to utilities. This solution provides utilities with real-time data regarding power consumption and also empowers consumers to make informed choices about energy usage.

2. GIS (Geographic Information System): This system, which serves as a reference system for the outage management system (OMS) and distribution management system (DMS), is comprised of two main parts (below). These two parts provide the OMS and DMS with the network model of a utility's grid, which is imperative for these two systems to function.
   - Digitized maps of utilities' service areas: Utilities can see latitudinal and longitudinal coordinates in a digitized map both for a surface area and each of the assets in that surface area, such as wood poles, transformers, circuit breakers and so on.
   - Facilities' management database: For each asset in a service area, utilities have access to a database that provides the geographic coordinates and location of that asset, in addition to significant information about that asset, including the nameplate from manufacturer, maintenance information, cable company equipment, phone company equipment, and utility equipment.

3. OMS (Outage Management System): The OMS gauges which pieces of electrical equipment are experiencing failure. The OMS gathers this information from the following sources:
   - Phone calls from customers: Fifteen years ago, customer phone calls were the only source of information for an OMS. Utilities had to wait for customers to call in to report outages, if those calls even came in. The OMS' performance was dependent on how many calls it got. The longer the delay for phone calls, the longer utilities were delayed in correcting power outages.
   - SCADA (Supervisory Control and Data Acquisition System) System: Approximately 10 to 15 years ago, the industry began requiring the integration of the SCADA system with the OMS. The SCADA system can immediately detect a change in state on any device on the grid. For example, if there is a fault on the system, the protective characteristics of a circuit breaker will detect the fault as soon as it occurs and will very quickly open to de-energize the line and prevent the disturbance from cascading into something more widespread, like a blackout. Immediately isolating the fault or problem and keeping it localized is key. While utilities still receive phone calls flagging outages, the integration between the SCADA system and OMS allows for a change of state and exchange of information much quicker than previously done.
   - Tweets from customers: GE has successfully integrated social media information, such as tweets, as another source of information for the OMS.

4. DMS (Distribution Management System): This part of the grid is considered the 'quarterback' of the four technologies (AMI, GIS, OMS and DMS), as it is the overall manager of the distribution system. The DMS is made up of two parts: the SCADA system and smart grid applications. The SCADA platform, which provides supervisory control and data acquisition functionality, serves as the foundation on which the smart grid applications overlay. Once the GIS provides the DMS with the grid network typology and configuration, the OMS is then integrated with DMS through the SCADA system. The DMS smart grid applications include FDIR, IVVC (integrated volt/VAR control), Three Phase Unbalanced Load Flow, Optimal Feeder Reconfiguration, and Load Estimator. Additionally, an Energy Management System (EMS) is comprised of the SCADA platform and special applications that deal with the generation and transmission parts of the system, instead of distribution, like the DMS.

EET&D: Why do utilities hesitate to implement integrated smart grid systems?

McDonald: We have to remind ourselves that utilities operate in a regulated marketplace – any investment that the utility makes is regulated in terms of the return on investment. Additionally, these regulations differ from state to state. In one state, policies may favor investments in smart metering communications, while another state may be more focused on improving the reliability of the distribution system. We must first look at policies and regulations to gauge to what extent a state encourages or supports an investment in a particular application.

Secondly, as previously mentioned, the distribution area of the utility system historically hasn't received significant investment. The technology for monitoring and control is very cost effective today, and the business case for remote monitoring and control is strong, but more than half of substations in the U.S. haven't had any sort of investment in automation. The AMI, GIS, OMS and DMS technologies and systems rely on the distribution system, which is imperative for an integrated grid.

Additionally, we must look at the DMS itself. The concept of a separate SCADA system for distribution management is a fairly new concept. Historically, the distribution system has been simple to manage with electricity flowing in one direction from source to load (a radial system), so the need for a separate SCADA system hasn't been there. Now, with the smart grid integrating renewables and power now flowing in two directions, the system is much more complex. This complexity has recently required utilities to think about a separate SCADA system for distribution, while also integrating the OMS, GIS and DMS together.

Utilities can't just invest in these technologies – but must integrate them together, which is a new concept. For this to happen, state policies must change to incent and encourage utilities to make these investments.

EET&D: Can you further discuss the role of industry standards - compliance and interoperability – with these smart grid solutions?

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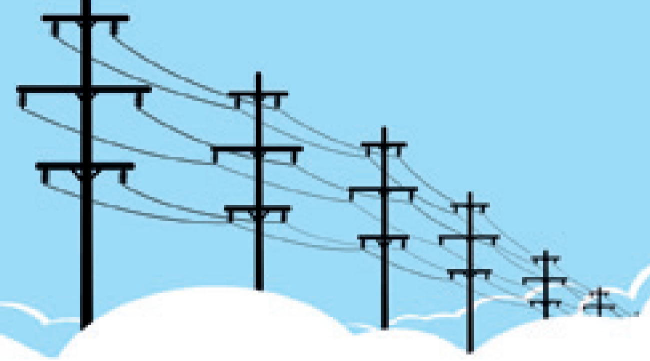


McDonald: The smart grid has emphasized transition from devices and systems to solutions. These solutions are driven by a utility's business needs, and the set of technology components that make up the solution are put together, typically from different suppliers. The concept of an industry standard forces consistency among multiple suppliers. These multiple components will only interoperate if all of the suppliers comply with the same industry standard and the components have been tested for interoperability.

There are two facets to success. The first is compliance. It ensures that suppliers are correctly implementing the standard. This can be tested by a third-party vendor, who will test compliance and award a certificate following the test if the supplier's device passes.

Secondly, interoperability testing is key. Once the supplier's device passes the compliance test, there may still remain incompatibilities between separate components. To solve this issue, industry organizations hold events called Plugfests, where equipment suppliers come together to ensure that equipment communicates successfully with equipment from other vendors. If not, suppliers will change the software on the spot and test again. These events ensure that all suppliers' components are fully interoperable, and that is the only way that smart grid solutions can be successful. As we transition into smart grid implementation, the role of industry standards has become much more important. The smart grid brought us the concept of solutions, which demands an emphasis on standards and compliance and interoperability testing.

EET&D: We can't thank you enough, John, for taking the time out of what I'm sure has been an absolutely hectic schedule. I know our readers will gain a lot of insight from your in-depth knowledge of smart grid. No one would ever want to see a repeat of Hurricane Sandy but it's reassuring to know that companies like yours are working around the clock at improving the technologies that can improve lives during the aftermath of a major weather event.

About the Interviewee: In his role, John provides the strategic leadership and develops the long term plans to optimize Digital Energy's competitive position. This is a new and highly visible position and will set and drive the vision that integrates GE's standards participation, and Digital Energy's industry organization participation, thought leadership activities, regulatory/policy participation, education programs and product/systems development into comprehensive solutions for customers.

John received his B.S.E.E. and M.S.E.E. (Power Engineering) degrees from Purdue University, and an M.B.A. (Finance) degree from the University of California-Berkeley. He is Fellow of IEEE, and was awarded the IEEE Millennium Medal in 2000, the IEEE PES (Power & Energy Society) 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. John is the IEEE PES Past President, CIGRE US National Committee (USNC) VP Technical Activities, and IEEE PES Substations Committee Past Chair. John is the Smart Grid Consumer Collaborative (SGCC) Board Chair, and the NIST Smart Grid Interoperability Panel Governing Board Chair.

GREEN OVATIONS

Innovations in Green Technologies

Reducing Peak Power Demand with Flywheel Technology

By Patrick McMullen, VYCON

Over the last century, epic advances have been made in our transportation technologies. From cars and buses to trains and planes, we have the freedom to travel at comfortable fares; however, not only are we still using primitive and environmentally harmful fuels and chemistries to propel our mass transit services, we are taxing the electric grid to do so.

Growing transportation problems, including gasoline prices and carbon dioxide emissions, are forcing city governments to consider implementing better transportation and energy initiatives in an effort to reduce the impact on our environment and taxes. As we know, constructing power plants and laying lines is expensive and time-consuming: according to a 2009 report by the Union of Concerned Scientists, between 2002 and 2008, cost estimates for a new nuclear plant rose from between US$2 billion and US$4 billion per unit to US$9 billion per unit.

Research and development of renewable energy sources continues to require funding commitments from municipalities, with these investments reducing emissions and fossil fuel dependence in the long run. While these new sources offer access to clean energy and utilize existing distribution systems, they do nothing to reduce demand or improve energy usage efficiency. Conserving for the future means adopting technologies that will minimize power usage through improved efficiency and more accurate forecasting and maximize existing infrastructure.

Energy Storage System Rides the Rails

In the U.S. and around the world, electrically propelled subway rail trains and light rail vehicles (LRVs) use AC propulsion with induction traction motors and variable voltage, variable frequency drives (VFD). Benefits of these electric trains over older DC drive trains include higher efficiency, reduced starting energy use, regenerated braking energy, lower maintenance, and a broadened range of operating conditions. Transit operators, however, have found that without an Energy Storage System (ESS) available to capture the regenerated power, electric trains and earlier DC chopper trains have not fully delivered their potential economic benefits. Specifically, these new trains are unable to achieve the expected reduced demand and energy costs from regenerated energy savings.

Electric trains draw a huge amount of energy to accelerate away from the platform – the same peak demand used as 1,000 average U.S. homes. As deceleration occurs pulling into the next station, the train sheds significant amounts of energy to stop the train. Up to 90 percent of that braking energy can be recovered and used to launch the train from the station, reducing demand on the local grid. If train stations can harvest the energy of incoming trains as they brake, they can re-cycle that same energy to launch the same train, or another train, as it leaves the station. That's the idea behind flywheels – providing clean and environmentally friendly energy storage.

For the most part, train departure schedules are managed by their power demands. Less frequent or staggered scheduled trains typically don't put unnecessary loads on the system, i.e. a 2-times or 3-times demand in power is created when two or three trains leave a station at the same time. Add a flywheel and you have a cost-effective energy supply that can provide a boost when it is most needed, potentially allowing more trains to run simultaneously and pull out of the station more quickly.

Transit operators and local utilities have a growing interest in finding an energy storage solution to capture the full energy savings benefit of regenerative braking. Operators are under constant pressure to reduce operating costs and improve service and reliability. Station energy storage can be used to reduce overall energy usage and peak power demand charges and to mitigate voltage sag and dropout problems. Utilities are under pressure to meet growing demand for power, and a source of 'free' recycled power that reduces the peak demand for rail allows utilities to allocate megawatts of power for a broad range of growing users. Fortunately, a flywheel energy storage solution can address these issues while providing a 'green' alternative over chemical-based batteries.

Traction Power Costs

Payments to electric utilities for electric energy and peak power demand are a significant operating expense for Transit Operators. Energy and peak power costs fluctuate and trend over time in response to complex market, regulatory, commercial, and political forces. Table 1 is a snapshot of U.S. utility rates during the summer of 2004. These rates are used to calculate cost savings in the case studies below.

	East Coast	West Coast
Energy Cost	\$0.07 / kWh	Variable by time of day and season: ~\$0.08 / kWh base ~\$0.13 / kWh during summer peaks
Peak Power Demand Cost	~\$7.0 / kW monthly charge, set by the maximum half hour of peak demand in the month	Variable by time of day and season: **[N1]** ~\$0.34 / kW monthly charge for the max half hour Plus ~\$0.70 / kW monthly charge during Partial Peak hour Plus ~\$7.5 / kW monthly charge during summer Peak hour.
Note [N1] Definitions of Peak and Partial Peak hours depend on the season. In a typical summer work day, Peak hours are 12 noon to 6 pm, and Partial Peak hours are 8:30 am to 9:30 pm.		

Table 1: Utility rates

Flywheel Energy

A flywheel system stores energy mechanically in the form of kinetic energy by spinning a mass at high speed. Electrical inputs spin the flywheel rotor and keep it spinning until called upon to release the stored energy. The amount of energy available and its duration is governed by the mass and speed of the flywheel.

In a rotating flywheel, kinetic energy is a function of the rotational speed of the flywheel and the mass moment of inertia. The mass moment of inertia relates to the mass and diameter of the flywheel. The kinetic energy of a high-speed flywheel takes advantage of the physics involved resulting in exponential amounts of stored energy for increases in the flywheel rotational speed.

There are advantages to using flywheel technology when compared to chemical batteries:

- **Response** – it can promptly store huge bursts of energy, and equally rapidly return them
- **Efficiency** – charges/discharges are made with very small losses; as an electrical storage system a flywheel can have efficiencies over 97%
- **Maintenance** – flywheels do not require cooling nor do they pose the chemical recycling/maintenance issues of conventional batteries
- **Lifespan** – flywheels have a typical lifespan of about 20 years, while a lead-acid battery needs to be replaced every three to seven years – and even sooner for high cycle applications

Flywheels have been used since the Bronze Age as a way to store kinetic energy. Many critical applications from data centers and medical imaging equipment to cranes benefit from flywheels' instantaneous energy storage. In a data center, the rotation of the flywheel is capable of generating enough energy during a blackout to keep the center up and running while backup generators activate. For mobile shipyard cranes, flywheels are used to recycle braking energy – saving on diesel fuel and polluting emissions. The newest application of flywheel technology is energy storage and deployment for electric trains. The flywheel operates in place of a substation, delivering power to the train through the third rail.

For major urban rail lines, any energy storage system must operate at a high duty cycle during long rush hours with close headways. In practice, this means the flywheel must operate at a duty cycle above 40 percent. In other words, it must discharge 15 seconds, idle for 20 seconds, charge for 15 seconds, idle for 20 seconds, and repeat the cycle continuously through extended rush hour periods. This rapid cycling capability separates flywheel technology from batteries. Flywheels are capable of millions of full charge and discharge cycles over the life of the system with no degradation in voltage, power, or storage. Flywheel technology is also considered the only green technology of the storage technologies applicable to the rail market and in the energy storage market in general.

The return on investment for flywheels as energy storage systems in rail applications is evident – they require little maintenance, are self-protecting during emergencies and are highly efficient with very low waste energy during charging, discharging and idling.

Energy Storage Technologies

Transit Operators have evaluated and tested flywheels, supercapacitors, and batteries for transit ESS application. Table 2 summarizes the advantages and obstacles for each. Flywheel demonstration projects in the transit industry include New York City Transit, London Underground, Paris, Lyon, and others. Both wayside and railcar demonstration projects are under way. The highest rated unit demonstrated to date is a 1 MW, 7kWh flywheel energy storage system, and larger units are now under development. Supercapacitor projects are under way in Portland OR (U.S.), The German cities of Koln and Dresden, and in Madrid, Spain.

ESS Feature	Flywheel	Supercap	Battery
Energy density	**O**	**O**	●
Cost / kWh	**O**	**O**	●
Power density	●	●	○
Cost / kW	●	●	○
Maintenance	●	**O**	○
Configurable rating	●	●	●
Operating life	●	○	○
Proven technology	**O**	**O**	●
Hazardous materials	●	○	○
Now in service	**O**	●	**O**
Key: ● Better	**O** Average	○ Worse	

Table 2: Energy storage comparison

Putting Flywheels to the Test

Recently, the Los Angeles County Metropolitan Transportation Authority (Metro) awarded a US$3.6 million contract to install a Wayside Energy Storage Substation (WESS) at the L.A. Metro Red Line Westlake / MacArthur Park Station utilizing flywheel technology developed by VYCON. The new WESS system will demonstrate how it can lower the cost of peak power demands, reduce energy consumption, decrease wasted energy and lower power demands to the utility during critical peak power usage.

According to L.A. Metro's project manager, Frank Castro, "Metro is committed to an extensive energy savings and sustainability program. In the last five years, two megawatts of photovoltaic energy-saving equipment has been already installed. The WESS Project alone, with its two megawatts of flywheel energy recycling power capacity, will double this number."

Potentially, the benefits of the new WESS system could include the elimination of train slowdowns and stop/starts by correcting low voltage occurrences, an increase in system reliability through greater power capacity, as well as a redundancy in power source for adjacent substation outage or emergencies.

Another advantage to the VYCON system is that it does not use onboard flywheels. Instead, the flywheels are used to store energy trackside at each station, meaning there are fewer limitations on size, and the weight of the device does not have to be transported.

At the Westlake and MacArthur Station on the LACTMA rail line, the flywheels will store 2MW and fit into the existing electricity substation. The power storage unit consists of four modules, each containing a high-speed steel flywheel and a motor/generator. Each module is approximately 0.9 m by 1.2 m (3ft by 4ft).

And other transportation hubs are looking to follow suit. The future is where flywheels are not only installed in existing public transport systems, but designed into them from the start. One of the key advantages being that new systems can alternate between the placement of a substation and flywheel storage to reduce overall infrastructure cost, as there is no need to drop power lines every mile.

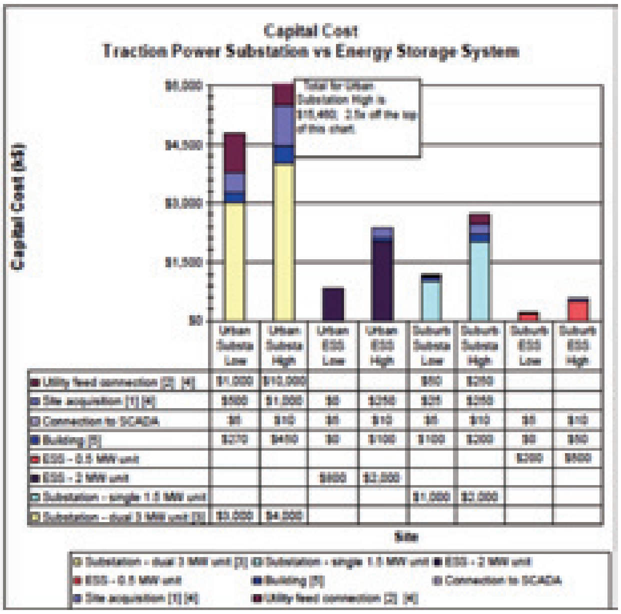
Solving Voltage Sags

Voltage sags result from physical limitations of the traction power supply including substation location, rating, and loads. In some transit systems, the substations are placed farther apart than optimal, due to civil structures or natural barriers such as tunnels, or economic barriers, such as the cost of urban real estate. Voltage sags can worsen when new higher power demand trains, increased service, reduced headway, or extended operations overburden existing traction power supplies; for example, higher density service, a line extension, or a new fleet of higher performance electric trains.

A suitably located energy storage system can supply current near the train when it is needed, decreasing the voltage drop so that operations are not disrupted. To assess voltage support costs and benefits, figure 1 shows a range of cost estimates to install a new substation to resolve a low voltage condition, for both urban and suburban locations. Figure 3 also shows the range of capital costs for an ESS installation which provides the equivalent level of voltage support.

GREEN OVATIONS

Innovations in Green Technologies



	Urban Substa Low	Urban Substa High	Urban ESS Low	Urban ESS High	Suburb Substa Low	Suburb Substa High	Suburb ESS Low	Suburb ESS High
Utility feed connection [2] [4]	$1,000	$10,000			$50	$250		
Site acquisition [1] [4]	$500	$1,000	$0	$250	$25	$250		
Connection to SCADA	$5	$10	$5	$10	$5	$10	$5	$10
Building [5]	$270	$400	$0	$100	$100	$200	$0	$50
ESS - 0.5 MW unit							$200	$500
ESS - 2 MW unit			$800	$2,000				
Substation - single 1.5 MW unit					$1,000	$2,000		
Substation - dual 3 MW unit [3]	$3,000	$4,000						

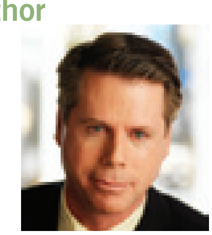
Figure 3: Traction Power Substation vs. Energy Storage System

Looking Ahead

Transit agencies are faced with constrained capital resources, rising energy costs, environmental commitments, and the challenge of meeting increasing ridership and maintaining system performance at the same time. Flywheel technology is ideally suited for electrified rail and subway systems, offering green, cost effective energy storage and recycling solutions. Not only can braking energy be captured and stored, but flywheel systems can also provide voltage support supplementing existing rail traction power substations. Metro transit agencies can benefit with improved performance, lower capital costs, and reduced energy usage.

Passengers may not understand the technology, but the effects – in terms of trains running more frequently, quickly, and smoothly – will be seen. Utilities and transit operators will notice reduced peak usage, lower costs, and seamless operations.

About the Author



Patrick T. McMullen is the Chief Technical Officer for VYCON. He has a BS, Mechanical Engineering, from the University of Notre Dame and holds an MBA from the University of Southern California. Patrick was a co-founder of Calnetix and has worked full time at VYCON since mid-2003. He has over 20 years of experience in the magnetic devices field for high speed equipment, with 14 years of experience in the magnetic bearing field. McMullen developed the original flywheel system concept while at Calnetix, where he served as vice president.

PART I – WHAT WE DISCOVERED

Bulk System Reliability Assessment and the Smart Grid

Insights and Recommendations from Exploratory Workshops on Evaluating Potential Reliability Impacts of Smart Grid Deployments

By Jason Taylor, Senior Project Engineer/Scientist, EPRI

A system can only ever be as 'smart' as its design. Achieving a 'smart grid,' therefore, depends on system designers having access to tools capable of assessing system reliability under an evolving portfolio of potential smart grid applications. In this paper, 'smart grid' denotes the application of advanced sensors and monitoring technologies, integration of distributed energy resources (DER), and coordination of distributed controls with grid operations. As the number of smart grid applications continues to grow, the development of new reliability assessment models, metrics, and analysis methods is vital to fully understand and assess the potential impacts and benefits of such applications to the bulk electric system.

Workshops were held in both Europe and North America to identify and discuss potential gaps and concerns in this area while capturing a broad range of industry experiences and perspectives. This paper presents findings from both workshops (Part I) along with a roadmap for future collaborative research and development (Part II).

R&D Challenge

Advances to existing or development of new reliability assessment tools may be necessary as smart grid applications may significantly alter domain characteristics as well as introduce new domain linkages (Figure 1). Additionally, advanced controls and communication technologies can improve system visibility and controllability but also increase overall system complexity. Reliability considerations, therefore, need to account for the increased dependence on these infrastructures as well as new resource operating characteristics, such as the variability and uncertainty of demand response. R&D is needed to identify the influence and pertinent characteristics of various smart grid applications and how best to represent these applications within reliability assessment practices.

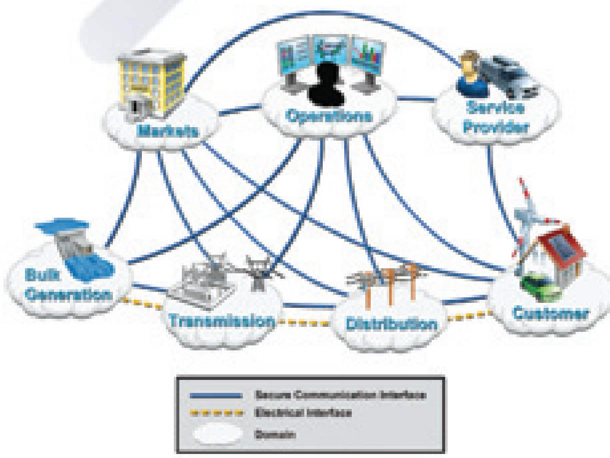


Figure 1: Smart Grid Conceptual Model – top level[1]

North American Electric Reliability Corporation (NERC) and European Network of Transmission System Operators for Electricity (ENTSO-E) [2], [3],[4] have acknowledged the need to advance current system planning and assessment tools to meet these challenges. Coordinated research in this area has thus far been limited but remains essential in the development of industry-accepted assessment tools.

Gerry Cauley, CEO of NERC sees it this way: "Integration of these new technologies requires changes in the way the bulk power system is planned and operated to maintain reliability. Further, additional tools/models are required to support their integration to meet policy and strategic goals."[5]

Exploratory Workshop Purpose

Two exploratory workshops were hosted by the Electric Power Research Institute (EPRI) to identify concerns and gaps in the understanding of the reliability impacts of smart grid applications. The events were held at NERC headquarters in Atlanta, Georgia and at the University of Manchester in England. Workshop participants included a diverse group of experts from utilities, regulatory organizations, vendors, and academia.

Reliability Assessment Concerns and Gaps

The smart grid encompasses a wide range of technologies and applications with the potential to impact overall grid reliability. The following is a breakdown of reliability assessment concerns highlighted by workshop participants:

1. Model and Data Limitations

Maintaining accurate component and system models has always been a challenge in power system analysis. This was made evident by workshop participants who highlighted the need for improved models for variable renewable resource technologies, advanced HVDC lines and converter stations, and generator control. Load models, in particular, are increasingly important as load progressively becomes a more significant system resource and a major factor in the changing dynamics of the system. Future models will need to include the characterization of distributed control systems, new load types such as electric vehicles (EV), and customer response and behavior elements.

The general lack of relevant system data, such as protection settings, operator actions, and climatic conditions were earmarked as a significant barrier to carrying out effective event analyses. It is also difficult to predict how different sources of uncertainty may impact system reliability. More robust sensitivity analysis tools are needed to predict, gauge, and account for potential impact to system reliability caused by 'source uncertainty.'

Advanced sensor and data collection technologies may help in verifying or refining system models. For example, Western Electricity Coordinating Council (WECC) found that its plant models did not represent actual system events as seen by SCADA systems (Figure 2) until they adjusted these models based on phasor measurement data.[6] Although visibility across all parts of the grid could improve system modeling and the forensic analysis of system events, the granularity needed to represent widespread smart grid controls and new load characteristics requires further research. Related data management, analysis, and visualization challenges must also be addressed.

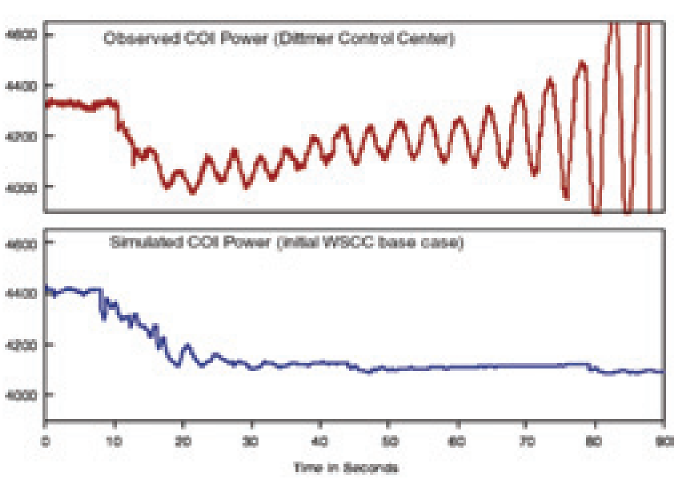


Figure 2: Example System Oscillations observed by SCADA and PMU measurements.[7] (IEEE© 2006)

2. Variable and Intermittent Resource Integration

The proliferation of variable renewable sources is increasing in both the United States and Europe. EPRI anticipates 135 GW of renewable energy sources in the U.S. by 2030[8] and the European Union (EU) has adopted a goal of 20 percent of the power generation from renewable resources by 2020. The Spanish transmission owner and operator Red Eléctrica reported that 32 percent of generation came from renewable resources in 2010, noting the variability of renewable energy sources and greater amount of DER. The challenge is to sufficiently characterize and account for the uncertainty associated with increasing levels of energy generated from variable resources.

Workshop participants indicated that new assessment methods, models, and metrics were required to evaluate system flexibility and reserve requirements in order to determine long-term operation needs under changing system resources, capacity, and networks. Just as importantly, these new techniques must be reasonable to execute, and the results must be directly applicable to system planning. To this end, active collaboration between academic research and the industry will be critical.

Potential issues include the retirement of mid-merit conventional generators due to market constraints associated with higher penetrations of wind and photovoltaic (PV) sources. These factors may necessitate the formulation of new capacity products to ensure sufficient reserves.[9,10] Methods to determine the features and characteristics of these new products still need to be developed. In addition, the adequacy of deterministic analysis tools in light of variable resources and smart grid technologies was questioned, with strong indications for further considerations and applications of probabilistic risk assessment (PRA) and planning tools such as ASSESS[11] and TransCARE.[12]

3. Protection Coordination

Two-way flows of energy between bulk and distribution systems represent challenges for the coordination of system protection. Particular interest was expressed concerning under-frequency load shedding (UFLS) and under-voltage load shedding (UVLS) programs. Distributed generation (DG), demand response (DR), conservation voltage reduction, and other smart grid applications can result in unplanned deviations from estimated circuit demands. If the circuits are part of a UFLS or UVLS the change in system demand may be less than anticipated in the design scheme and will not result in the expected load reduction.

Methods and metrics are needed to facilitate easier, less time-intensive determination of UFLS and UVLS relay settings and locations while accounting for geographic and temporal variations of distributed resources and other smart grid applications. Conversely, increased visibility and controllability may permit more advanced and granular load-shedding schemes.[13] Advanced protection functions and evaluations must be sufficiently robust, providing the desired operation under changing conditions and accounting for the integrity and trustworthiness of the input signals.

4. Distributed Energy Resource Integration

In the context of this paper, DER includes any DG, renewable energy resources (RES), energy storage (ES), and DR connected at the distribution or end user. These resources may be under local control or under the control of a distribution management system or load aggregator.

A NERC report by the Integration of Variable Generation Task Force (IVGTF) indicates that although DER represents a small portion of Generation in the United States, plug-in electric vehicles (PEVs) and stationary storage could reach nearly 5 GW and DR could grow from the current 40 GW to 135 GW in a decade.[14] In addition, the Solar Energies Industries Association (SEIA) reports almost 20 GW of installed PV capacity in 2011. This more than doubles the 900 MW installed in the U.S. in 2010.[15]

DER penetrations are growing at an even faster rate in Europe. The Italian energy company Enel reported a 1.35 GW increase of DG and RES on its system in 2009.[16] By 2011, the installation rate of distributed PV alone had risen to 2.67 GW.[17] Germany has also seen a significant penetration of DER with 7.4 GW of additional PV capacity installed during 2011 raising the total installed PV capacity to 24.8 GW.[18]

Workshop discussions revealed the overall need for models that sufficiently represent DER performance, availability, deliverability, reliability, and control functions. Research to identify the level of modeling detail and visibility requirements for various applications was is also needed. Several potential DER reliability issues and assessment concerns stemming from particular applications and characteristics were also noted and described below.

Ancillary Services and Flexibility Participation. Forecasting and assessment tools are needed to evaluate the reliability benefits and limitations of incorporating high levels of DER, providing regulations and reserves while accounting for factors, such as resource performance, availability, and sustainability. For example, current PJM Reliability Council rules place a 25 percent cap on DR in PJM's synchronous reserves program.[19] Interest on increasing this cap while maintaining system reliability was expressed during the workshop.

In addition to reserves, large aggregate DER is often considered a possible resource to provide system flexibility across various time scales in light of increasing levels of renewable generation. For example, PEVs and other forms of DER are often seen as potential resources which can be utilized to offset large variable generation.[20] However, considering its variability and uncertainty, additional models, methods, and metrics are needed to fully gauge and understand the flexibility benefits of DER.

System Restoration. Smart grid-dispatched DER represents a potential component in black start operations and the mitigation of cold load pickup issues. Evaluation of the implementation design and effectiveness of these potential operations is still in the early stages. Non-coordinated automatic reconnection of a large number of DER could adversely impact restoration efforts and it too will require further investigation.

System Event Ride-Through. Bulk system-level events can result in low-voltage and under-frequency conditions that propagate down to the medium- and low- voltage levels. The potential then arises for such events to violate local grid codes or IEEE 1547[21] standardized disconnecting requirements for DG during abnormal voltage and frequency events. At high penetrations of DER, these events can result in the disconnection of large numbers of DG, with adverse impacts on the bulk system.

During the 2003 blackout in Italy, for example, 1700 MW of DG tripped at an under frequency of 49 Hz – further increasing the shortage of generation during the event.[22] The abrupt disconnection of increasingly larger amounts of distributed sources can also result in longer voltage recovery times as shown in Figure 3. Challenges in this area include addressing the lack of visibility by developing new requirements and metrics, constructing equivalent models that account for step-down transformer and distribution circuit configurations as well as DG output, and developing screening tools to identify areas of system vulnerability.[23]

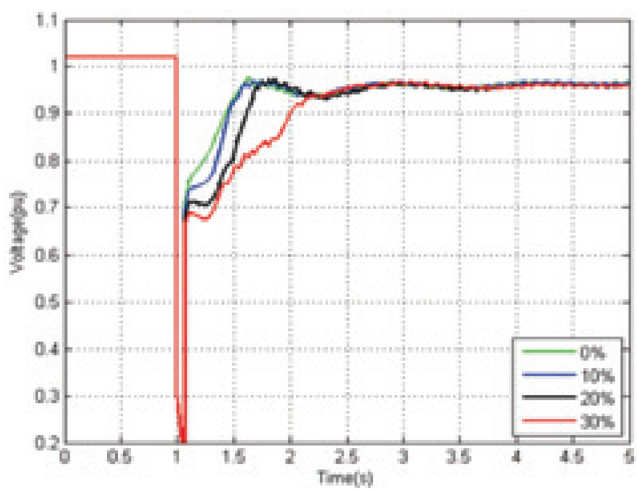


Figure 3: Example Voltage Response at Different Levels of Distributed PV Dropout[23]

Rotor Angle and Frequency Stability. High penetrations of DER and renewable sources coupled with retiring generation could decrease overall system inertia and primary frequency response, thereby increasing stability concerns.[24,25] However, industry development of new assessment methods and dynamic models has been limited. Although inverter-based bulk system and distributed resources have the potential to emulate traditional source characteristics such as generator droop response, these applications are in the initial stages and require additional analysis.[26]

Voltage Stability. In the U.S., distributed resources are prohibited from regulating voltage by IEEE 1547. The displacement of voltage-regulating generation by DER could be a voltage stability concern. Even when DG and inverter-based resources are operated to provide voltage or reactive power, the support to the bulk system may be limited as illustrated in Figure 4.[27] Furthermore, potential voltage support from the distribution management systems (DMS) will need to be coordinated with voltage-regulation mechanisms and transmission system requirements.

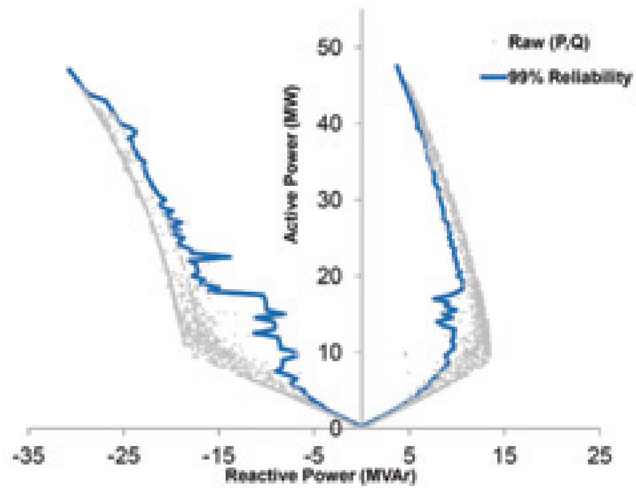


Figure 4: Evaluation of Aggregate DG Reactive Power Support at the Transmission and Distribution Interface (Source: Andrew Keane, UCD

Customer Behavior and Participation. The use of dynamic pricing, such as time-of-use (TOU) rates, critical peak pricing, and real-time pricing is expected to be a key feature of the smart grid. The reliability benefits or ramifications, like price volatility, involve complex dynamic relationships between markets, end-use customers, and energy management systems that are not completely understood or easily captured in today's power system analysis tools. Even with incentive-based DR implementations, accounting for customer behavior is essential to understanding the availability and frequency of the many emerging resources.[28]

5. Information Technology Dependence

Smart grid applications will greatly increase the power system's reliance on advanced communications and information technologies. Information and communications network failures – whether unintentional or deliberate – may subsequently result in distribution or transmission system reliability events. Traditional reliability analyses have focused only on the power portion of the grid.[29] Consequently, traditional hierarchical levels (Figure 5) do not readily incorporate virtual power plants, DR aggregators, and other distribution-level (HL III) applications that can impact bulk system reliability (HL I and HL II) and whose operations are communication system dependent.

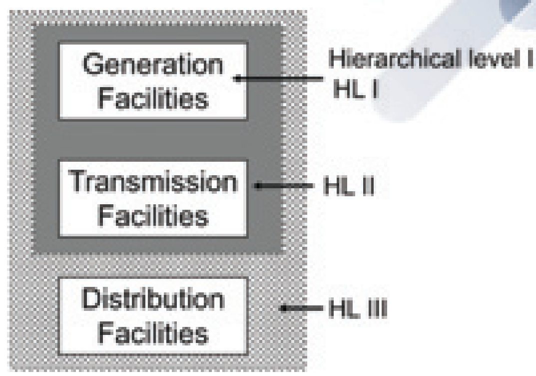


Figure 5: Reliability Assessment Hierarchical Levels (Source: Sudhir Agarwal, General Reliability)

The need for tools which can account for communication system integrity, device failures, and cyber security risks within the overall reliability assessment was a common theme at both workshops. Areas of further research include:

- Incorporation of advanced communication and control failure modes and physical system interdependence into system contingency evaluations
- Assessment of physical and cyber operational impacts from cyber events and communication failure events
- Data collection and model formulation concerning communication and control asset life cycles and failure rates
- Assessment method derivation and event-driven co-simulation of cyber and physical systems
- Development of equivalent reliability models for the communications-dependent aggregation of DER

6. Control System Architecture Interaction and Design

Intertwined with communications system dependency is the increased use and subsequent dependency on automated control systems. This includes special protection systems (SPS), remedial action schemes (RAS), and wide area management systems (WAMS). A need was expressed for tools that can quantify benefits and risks with increased levels of automation, represent interactions between centralized and decentralized controls, and incorporate important market functions. Detailed investigations of the fidelity required in representing telecommunications and wide area control schemes are also needed. Although smart grid activities have spurred advancements in distribution planning tools, such as EPRI's OpenDSS simulator[30] and DOE's GridLab-D,[31] similar advancements are needed in bulk system planning tools. Nonetheless, advanced distribution simulation tools are valuable resources that can form the basis for gauging changing distribution system characteristics and the development of representative load models.

7. Education and Training

The education of planning, operations, and field personnel in light of increasing system complexity, new technologies, and changing system characteristics was a particular concern discussed during the workshops. Advancements in assessment models, methods, and metrics incorporating emerging technologies and applications were recognized as important components of a better understanding of technology applications and system interactions. Simulation and modeling tools will generate the wider body of knowledge needed to determine new procedures and system design criteria; these tools can also serve as training platforms.[32] Education and training are also equally central to the application and acceptance of future assessment tools.

Reliability and Performance Indices

Understanding and gauging the performance of an increasingly complex system require reliability and performance metrics for specific technologies and for the overall system. These metrics may not necessarily fit traditional conventions. For instance, performance indicators of curtailment and demand response will also need to account for inconvenience to the end user as well as other extraneous factors such as ambient temperature.[33] Several assessment gaps requiring future research were discussed during the workshops:

- The effectiveness of peak demand-based metrics, such as loss of load expectation (LOLE), in the presence of variable resources, storage, and smart grid demand-shaping capabilities
- Flexibility indices and assessment methods for distributed resources, e.g., storage and DR, and overall system performance
- Metrics quantifying the reliability and performance of aggregate demand-side management operations and microgrid operations
- Visibility, controllability, and risk metric associated with distribution-centric smart grid applications
- The identification of measurable cyber security parameters and potential risk metrics
- The application and integration of PRA methods and performance indices in system planning

In the next issue of Electric Energy T&D, EPRI's future research framework will be laid out. It will include potential case study and assessment areas; discussions on the NERC Smart Grid Task Force and recommended work plan; ENTSO-E and EDSO-SG research, development, and deployment program; and EPRI grid transformation and modernization outlook.

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EPRI would like to acknowledge and thank all attendees at both the European and North American workshops for their active engagement and valuable input.

About the author

Jason Taylor is a Senior Project Engineer in the Power System Studies Group at EPRI. Dr. Taylor has worked in the industry for over a decade and holds a doctorate from Auburn University. His current research targets the advancement of reliability assessment metrics, models, and methods needed to evaluate and design a 'smarter' power system. He is a member of the NERC Smart Grid Task Force and a Task Force Leader within the CIGRE committee on Planning and Optimization Methods for Active Distribution Systems. Dr. Taylor can be reached at *jtaylor@epri.com*

Designing Operational Excellence – The Role of Intelligent Modeling Tools in T&D

By Peter Manos, Principal Strategy Consultant McDonnell Group

Design tools and the shift to engineering-centric workflows

Utilities are engaged in a complex balancing act in which next-generation design, modeling and visualization tools are playing an increasingly important role. Recent initiatives at Duke Energy and Southern California Edison provide good examples of challenges being addressed by leading utilities through their deployments of new design tools.

Related trends have been confirmed more widely through 31 interviews of North American and European utility decision makers as part of a McDonnell Group research project in late 2012.

The conversation about the importance of utilities' design tool improvements is shifting from software-centric to engineering-centric concerns.

One utility's research participant echoed statements made by many others regarding the history behind the utility industry's shift:

> "In the 1990's with early systems such as AM/FM and GIS, we basically duplicated a paper process. The software solutions back then were such a big efficiency improvement, we did not have to be as process oriented. Now we are advancing our engineering processes, and getting a next-generation set of benefits by operationalizing best practices instead of using IT to automate paper processes."

Panelist presentations from Arnold W. Fry, Manager, Engineering Standards Transmission Asset Management with Duke Energy, Debra Brooks, PoLAR Project Manager at Southern California Edison, and McDonnell Group highlight these and related developments at a session at the DistribuTECH 2013 Conference with an interesting title: ***Hand That New Kid a Mouse Glove: Intelligent Modeling and Visualization Tools for Enterprise Work Flow Optimization.***[1]

Utility design and engineering staff need not wear a mouse glove like Tom Cruise in the movie *Minority Report* but they need tools to optimize design, O&M workflows and related compliance tracking as well as customer service. At the same time utilities need to support the influx of younger, tech-savvy personnel who are an important part of the changing landscape at T&D and substation departments. With all of these converging needs, technology is helping to close the gap by becoming more and more intelligent in interaction and visibility; and some of the capabilities - once only imagined in a design department – is not as far as one might think from the imaginations of Hollywood today.

Modeling and visualization – keys to striking a balance

What are utilities seeking to balance? They have to optimize their financial and service performance while improving numerous workflows and addressing critical workforce issues at the same time. The use of next-generation intelligent, model-based design and visualization tools helps ensure the more rapid recruitment and training of the younger generation of knowledge workers coming on board. As one research participant stated:

> "As you get new engineers coming on board, if you have a really strong design system and you have good compatible units they become productive much sooner, instead of it taking two years for them figure out how we design our distribution system. We can use the technology to build the institutional knowledge into the application. So when they sit down at their desk they have all that knowledge built into it instead of their having to learn at the knee of a more experienced engineer."

The use of the latest tools also contributes to the longer-term retention of tech-savvy employees, and sets the stage for their greater contributions to enterprise-wise improvements.

It is important to highlight the role played by modeling, design, and visualization tools in creating better processes and setting the stage for breakthrough insights. Models help us to solve problems. But model-based ideas are such a basic aspect of how engineers think it is easy for those of us who are engineers to take them for granted. Worse yet, non-engineers in positions of utility management both in and out of IT related functions, as well as associated consultants and analysts, often fail to give models their due consideration when evaluating opportunities for improvement.

So a quick look back to modeling's roots provides clarity about the value of models and the leverage we gain when we use models effectively:

- One of the earliest known examples of modeling's role in solving engineering problems dates back to the third century BC, when Archimedes developed a method for finding any object's center of gravity. Archimedes went beyond his predecessor Euclid, who was stuck in the realm of purely abstract ideas. Instead, Archimedes derived the principles of levers and leverage that remain fundamental laws of mechanics 2,300 years later.

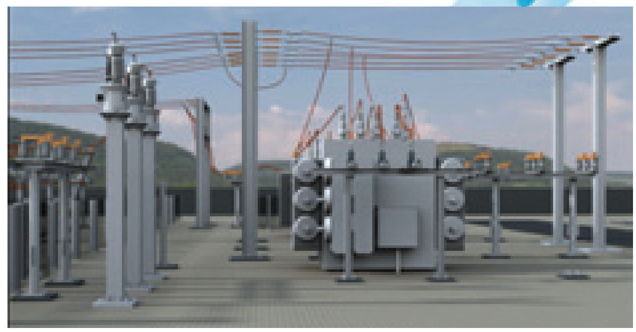
- What was the key to this lasting insight? According to a recent biographer, Archimedes' early use of modeling 'enabled the solution of previously intractable problems in mechanics, by mathematically collapsing real objects into imaginary points of mass.'[2]

If you consider the accomplishments not only of Archimedes, but of three of the most important scientists who came after him, they all had to rely upon visualization and modeling tools to make their great breakthroughs. From Galileo's trigonometry and Newton's calculus to Einstein's geometry of curved space, each of these great scientists followed Archimedes' example – they all relied upon a model as the basis for their breakthroughs.

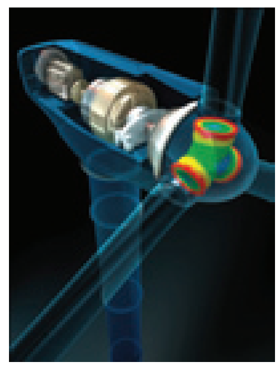
These fundamental leaps that have created valuable insights for humanity always involved making an association between a mathematical concept and a physical object. This is modeling.

Along with modeling, visualization is a related core element of how human beings solve problems, address complexity, and orient themselves. Visualization was a key element of the scientific models described above.

As with famous scientists, modeling, visualization, and design tools can also help utilities solve problems and balance numerous priorities. A whole new generation of tech-savvy young employees is coming on board, precisely when the depth of knowledge and experience of an older workforce needs to be retained in the face of numerous retirements.



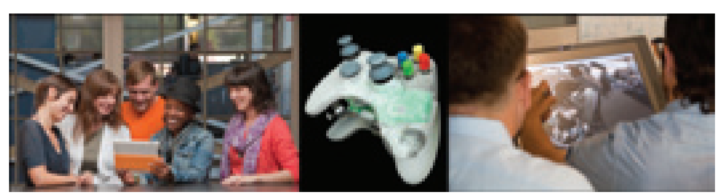
Modeling and design tools enable knowledge transfer and more rapid on-boarding of new personnel. (Image courtesy of Automationforce)



Rendering of a wind turbine illustrating workflow progression and demonstrating the capabilities of Autodesk's Digital Prototyping software products.

As one research participant stated:

"The more tech savvy, younger newcomers have often been surprised to see less than the latest technology in place and tend to seek employment elsewhere. These younger employees increasingly feel less and less loyalty to their employers. Anyone who thinks the utility industry is immune to this is living in a dreamland because I've been seeing it at many utility companies. The newcomers are up on the latest technologies, and want to stay that way. They will move to other companies or industries if they do not feel they are staying up to date in their work by using the latest design technologies. They want to feel they are accomplishing something. They want to be challenged."



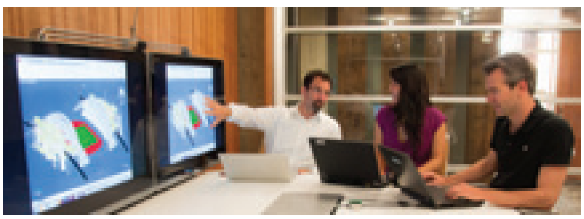
The millennial generation differs to previous generations in communication style, in ideals about technology; and in preference to merge gaming and 3-D experience with their careers. Old school is not always cool. Rendering of a video game controller highlighting circuitry and components. Rendered in Autodesk(R) 3ds Max(R) software.

Ultimately, as participants from leading utilities involved in McDonnell Group research indicated, the top priority when implementing has to be the utility personnel, not the IT solution. The solutions need to empower people to be successful. Participants in the McDonnell Group research made statements such as the following:

"Drawings need to communicate and translate into real work. This way you don't get into those situations where the crews get out in the field and they cannot complete the work."

"The biggest thing you need right now are tools that are functional and reliable, that support not just throughput but quality and also enable you to more quickly get new people up to speed – nothing can be achieved in the long run if you are not enabling your people."

"The depth of our design solution is critical to meeting our company goals in electric distribution. With what we are implementing one of management's key goals is to eliminate some of our older legacy software and get things more standardized."



Modeling can help to improve collaboration and convey information bridging the gap between engineer/designer and non-technical stakeholders

Key findings of The 'Designing Operational Excellence' study

A study completed in December 2012 by McDonnell Group, *Designing Operational Excellence: Financial and Service Performance Improvements and the Role of Intelligent, Model-Based Design and Visualization Tools*, surveyed a diverse mix of utility professionals, as shown in Figure 1.

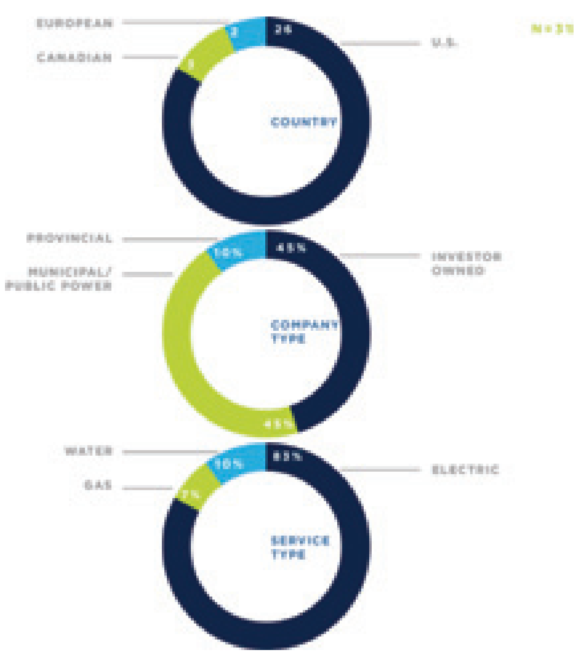


Figure 1
(Access the design study at *www.aec-projects.com/mcdonnell-group-design-study*)

In terms of the individual design groups within these utilities, the survey sample consisted of a broad and comprehensive mix of small, medium, and large design departments. Participants universally recognized the importance of the design function, both for meeting internal transmission, distribution, and substation department goals as well as for meeting overall company goals. Utilities represented in the sample are seeking to increase the uniformity and efficiency of workflows that employ data from design solutions across their current mix of WMS/OMS/EAM/ERP and GIS solutions.

All 31 participants recognized the key role of better design solutions, whether in distribution, transmission or substations.

Distribution system design teams are starting to increase their use of 3-D design tools, but currently remain at much lower usage levels for 3-D work compared to their counterparts in other areas of utility design work. Specifically, distribution design participants use 3-D design capabilities in only 15 percent of areas as shown in Figure 2, with substation more than double that amount (32%) and transmission usage levels of 3-D almost triple (41 %).

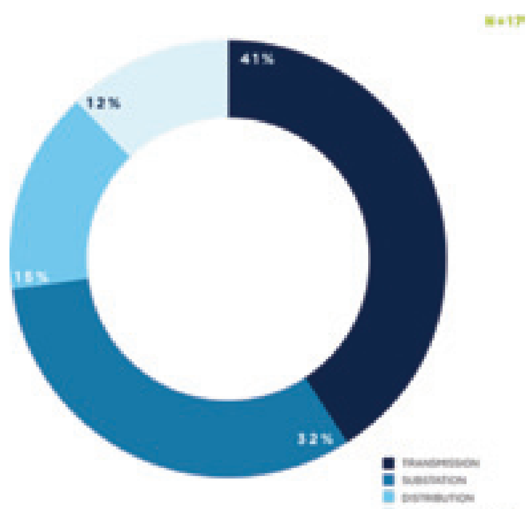


Figure 2: IN WHICH AREAS ARE YOU CURRENTLY USING 3-D DESIGN TOOLS FOR SOME OF YOUR DESIGN WORK?
(Access the design study at *www.aec-projects.com/mcdonnell-group-design-study*)

Demand for these tools is in part driven by the ability to see how designs will look in three dimensions and to rotate and analyze them from different perspectives. An example of the typical comment by substation and transmission design decision-makers regarding the value of 3-D involved the following areas of importance among others:

- Substation rebuilds in constrained environments
- Clearances being better understood
- Ability to use 3-D to enable third-party stakeholders as well as internal utility staff better visualize how prospective designs will look, in advance of finalizing the design options.

Although current usage levels of 3-D in distribution are lower, as shown in Figure 3, interest levels are high, spanning both overhead and underground distribution as well as smart grid initiatives and other aspects on the low voltage side of the grid (e.g. renewables and other distributed generation).

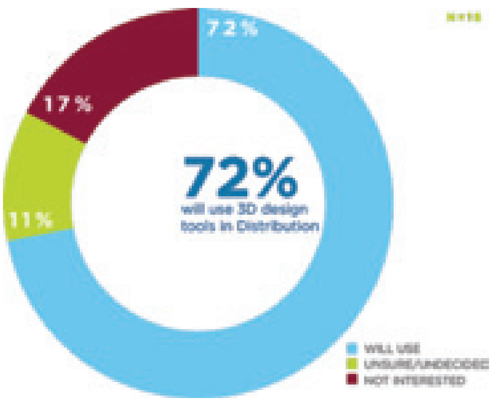


Figure 3: FOR ELECTRIC UTILITIES NOT CURRENTLY USING ANY 3-D DESIGN, MODELING AND VISUALIZATION TOOLS IN DISTRIBUTION, ARE YOU INTERESTED IN MOVING TOWARD THE USE OF 3-D DESIGN TOOLS?
(Access the design study at *www.aec-projects.com/mcdonnell-group-design-study*)

Another one of the next great leaps in improvement initiatives described by utilities involves having 3-D visualization and modeling tools at the designer's fingertips. Having 3-D tools enables a deeper understanding of how increasingly complex systems can be designed in a more coordinated fashion involving a more complex community of stakeholders, customers, and third party contractors.

"Helping everyone see prospective designs is of great value. For example, a couple of times a month we do a design presentation showing every design and what we intend to build. If you can put that in 3-D it suddenly becomes very real for the participants versus 2-D."

Visualizing existing assets in the context of the real world helps to provide enhanced understanding of existing conditions data and improved coordination with internal and external stakeholders. 3-D modeling of utility environments supports 'Call before You Dig' helping to prevent expensive repairs or relocation projects, and better supporting safety. (Data for 3-D model courtesy of Okaloosa Gas District)

Conclusion

Distribution system decisions are increasingly being driven by the need for greater accuracy and more robust processes to support real time updates and job tracking. The benefits of intelligent, model-based design and visualization tools are also leading to their deeper utilization to address large complex design jobs for transmission and substations and civil designers as well.

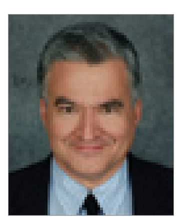
As mentioned, owing to the way software systems have evolved at utilities, the benefits being sought now are often part of a more comprehensive planning process, while earlier software systems may have brought benefits without a strong need to consider the overall impact.

The newer, intelligent model-based design tools are an important element of plans leading utilities are putting in place to find the optimal balance point between complex operational requirements, financial constraints, and reliability and customer service excellence goals.

There is a clear need to balance an increasingly dynamic set of constraints. Capital improvements to plant in service are requiring greater design tool utilization to better track projects and to collaborate in an environment where stakeholders, customers, and third party contractors as well as utility personnel need access to real-time information that must be accurate and reliable.

A valuable contribution to meeting these goals is being made by intelligent, model-based design and visualization tools and accompanying 3-D capabilities. The contribution being made by these tools is going to increase significantly in the future.

About the Author



As Principal Strategy Consultant at McDonnell Group, Peter provides strategic consulting services, competitive market positioning and analysis, and support of subject matter input and content for research programs. Along with numerous enterprise software vendors and equipment manufacturers seeking to better position their utility product offerings, Peter has also worked with numerous electric, gas and water utilities providing consulting and benchmarking services. Peter earned a B.A. in philosophy from Vassar College, a B.S. in electrical engineering from Polytechnic University of NY, and an M.B.A. in marketing and finance from NYU Stern School of Business. Peter is a member of the IEEE PES. Please contact him at *peter@themcdonnellgroup.com*

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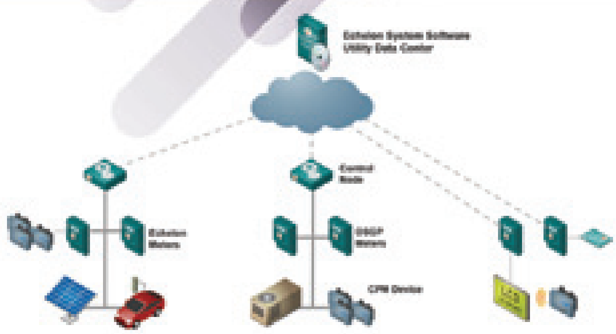
Smart Meters help SEAS-NVE meet Denmark's Ambitious Energy Goals

By Michael Anderson, Echelon and Bo Danielsen, SEAS-NVE

Denmark takes renewable energy seriously. According to the Danish Energy Agency, renewable energy sources accounted for 40.7 percent of domestic energy produced in the country in 2011. The country has one of the world's most ambitious goals for switching from petroleum-based and coal-based sources.



Smart Three-tier System

While wind energy has been the most prominent type of renewable energy in Denmark – the Danish wind turbine industry is the largest globally – solar panels are also gaining ground. In fact, the Ministry of Foreign Affairs of Denmark reported that by the end of 2012, the country had already reached its 2020 goal for solar energy.

An important player in Denmark's energy industry is SEAS-NVE, the country's largest consumer-owned energy company. Formed in 2004 as the merger of two energy companies – SEAS and NVE – each established in the early 1900s, SEAS-NVE represents a wide range of products, from energy and grid products to advanced consulting services on wind farm technology.

Four years after the merger, SEAS-NVE set out to replace its aging meter infrastructure, issuing a bid that was awarded to Echelon. Many energy companies choose smart meters to improve their billing processes, but SEAS-NVE recognized that in addition to billing, smart meters would allow them to solve power quality issues, respond faster to outages, and better manage energy efficiency.

By 2012, SEAS-NVE had successfully deployed 380,000 Echelon smart meters, via their service provider Eltel Networks and including billing software from Echelon partner Görlitz Lukia. These smart meters are helping to support Denmark's ambitious energy goals, while also boosting customer satisfaction with the company.

Simplifying Solar Installations

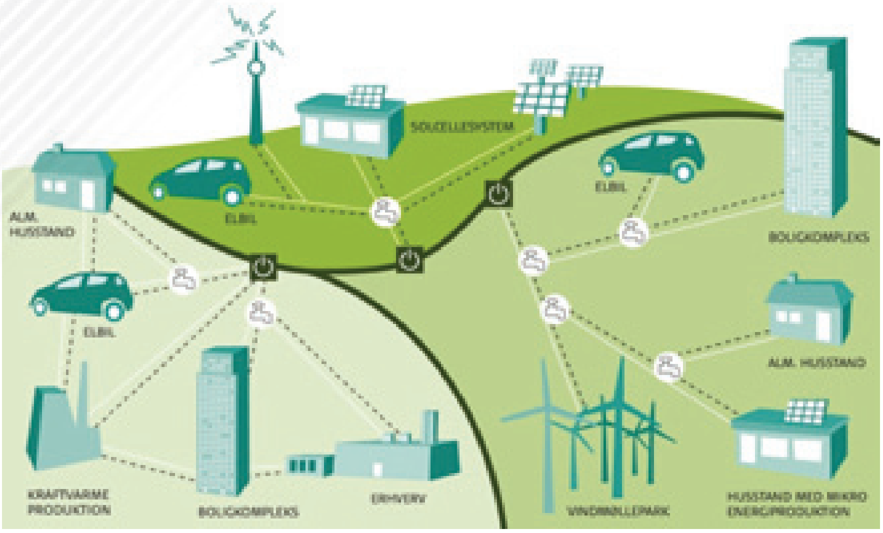
Solar panels have long been part of Denmark's renewable energy mix, but the difference today is the sheer number of solar panels installed: The beginning of 2012 saw a 10-fold increase in solar panel deployments.

Solar installations complicate the traditional one-way relationship between energy producers and energy consumers, allowing consumers to generate a portion of their own energy needs and to distribute excess electricity back to the grid.

Having the Echelon smart meters made it easier for SEAS-NVE to keep pace with solar implementation. For one thing, the company's technicians did not have to visit every consumer in person for each installation. Instead, SEAS-NVE could re-program the smart meters remotely to handle the more complicated interactions between consumers and the energy grid.

This re-programming capability alone saved SEAS-NVE approximately DKK 6 million ($1 million USD) in installation costs for 3,500 solar consumers. If each of their 380,000 residential consumers were to install solar panels, the installation savings could reach as much as DKK 570 million ($99 million USD).

Smart Meters help SEAS-NVE meet Denmark's Ambitious Energy Goals



Managing a power grid with a range of power sources – from microenergy generated by residential solar panels to windmill farms to large commercial generators combining heat and power production – is a huge challenge. SEAS-NVE set out to replace its aging meter infrastructure and has incorporated Echelon smart meters to manage, detect, and adjust power flow based on established criteria, regardless of power source. Eltel deployed these smart meters which provides energy customers a modern power grid system control resulting in lower costs.

Addressing Power Quality Challenges in Solar Panels

Once solar panels are producing power, SEAS-NVE consumers can check their smart meter to see how much power they generated for themselves and how much they provided to the grid. To date, solar consumers have been able to freely transmit their production into the grid. Currently, 36 MW capacity is being added to Denmark's grid by SEAS-NVE consumers.

Echelon's NES System Software has also helped SEAS-NVE's rapid expansion in solar panels. NES System Software is part of Echelon's three-tiered Energy Control Networking grid management platform, which also includes smart meters at the device level, and data concentrators or control nodes that collect meter and grid device data. The NES System Software seamlessly delivers all this data so it can be used by applications running at the utility head-end, such as mobile device, outage, and distribution management systems (MDM, OMS, DMS).

At SEAS-NVE, the NES System Software monitors the grid to make sure the voltage levels are within acceptable ranges. In the past, most voltage quality investigations were triggered by consumer complaints, like dimming or flickering lights or equipment failure.

Before smart meters, the utility would respond to a customer's complaint by sending linemen to the location to obtain initial readings and to identify the severity of the fluctuations. If the linemen could not immediately find the problem, they would install power quality recording devices at the consumer's point of common coupling, inside the consumer's location, and at various sites along the circuit serving the consumer location. Voltage readings were recorded over a given time, which was determined primarily by the frequency of malfunctions.

Using smart meters and NES System Software, SEAS-NVE can set a series of alarms and events that allow the utility to monitor and identify voltage quality problems at the same time the consumer notices it – or even before the consumer experiences any significant equipment malfunctions or failures.

The event log records the occurrence of meter events and fault conditions that are selected to be logged, along with the date and time of each event occurrence. The meter provides power quality measurements for the following: Voltage (RMS) sag (under voltage), Voltage (RMS) swell (over voltage), Over-current (RMS), Power Outages, Frequency, Phase Loss, and Total Harmonic Distortion (THD).

By recording these events, SEAS-NVE can better deliver the correct voltage level to each consumer's house. By collecting and analyzing events, and being prepared to monitor the grid where voltage levels have been exceeded, SEAS-NVE can meet its obligation both to its customers and to regulatory mandates.

Outage Response, Grid Reliability, and Customer Satisfaction

To respond to outages and maintain the reliability of its grid, for electricity generated by both renewable and non-renewable sources, the SEAS-NVE installation uses its series of alarms that notify the system when the power is out at points in the grid. This allows the utility to begin predicting issues before the customers call.

Knowing when an area is down gives the utility the advantage of isolating the problem. Once the outage is identified, SEAS-NVE can begin to restore power, thus reducing outages and avoiding surge-caused damages and lengthy power losses.

With the smart meters, understanding patterns has become part of the utility's post-power outage processes. SEAS-NVE can analyze usage in the area where the power failed and can differentiate between failures that are utility problems and failures created by customers exceeding energy limits. As a result of this capability, maintenance costs under the NES system have improved for SEAS-NVE, going from averages of DKK 6 million (just over $1 million USD) under the old system to current maintenance costs of as little as DKK $1.5 million ($260,000 USD).

The smart meters allow SEAS-NVE to schedule power quality measurements on a different cycle than billing data, so they can review history and troubleshoot the grid when problems are reported – rather than sifting through a mountain of data. As a result, the utility has decreased the time and cost of analyzing problems in the field, so it can focus on delivering reliable service to its grid users.

Throughout the transition to smart meters, SEAS-NVE has boosted its customer satisfaction ratings, and not just with its solar customers. The deployment by Eltel of 380,000 Echelon smart meters was completed with a consumer complaint rate as low as 0.5 percent – 10 times better than their expected target. During this smart-meter deployment, 99 percent of residences were reached for their 15-minute scheduled appointment. Eltel installed as many as 2,000 meters on a peak day, and those same meters were up and running and communicating with 99.7 percent to 99.9 percent reliability on the same day.

Eltel technician on site

Whether to support its burgeoning solar and other renewable energy resources, improve the power quality throughout its grid, or to achieve high customer satisfaction ratings, SEAS-NVE is discovering the advantages of using smart meters to manage its energy grid as a data-driven entity.

About the authors

Michael Anderson is Senior Vice President, Worldwide Markets, for Echelon. During his career he has held senior executive roles at a variety of high-growth and established telecommunications and high-technology organizations. Before Echelon he served as president of the Next Generation software division at Telcordia Technologies, responsible for vision and strategy as well as the sales, alliances, go-to-market, and product development teams. Anderson began his career at AT&T and was recently noted as one of the Global Telecom Business top 100 industry executives

Bo Danielsen has 20 years of experience in the electricity, telecom, and utility industry, with formal education as an engineering technician combined with a business and management degree. For the last five years he has served as head of the metering department for SEAS-NVE, the largest company in Denmark with smart meters, leading an organization of 55 people. In addition to managing current rollouts of smart meters to existing customers, Danielsen also is involved in future development and usage of the meters, with focus on the future smart grid.

Acting on the Deluge of Newly Created Automation Data:

Using Big Data Technology and Analytics to Solve Real Problems

By CJ Parisi, Dr. Siri Varadan, P.E., and Mark Wald, Utility Integration Solutions, Inc. (UISOL)

The amount of data available for use by distribution system operators has grown by orders of magnitude due to the rapid growth in the number of intelligent electronic devices (IEDs), sensors, and Advanced Metering Infrastructure (AMI) devices. Mechanisms are needed to create new value from this wealth of data without overburdening operations and engineers, especially during emergencies. Whether the data supports modeling, comes from external sources or is cultivated from real-time operations, effective results rely on creating actionable information from the data streams created by new automation technologies.

> In information technology, 'Big Data' is a collection of data sets so large and complex that it becomes difficult to process using on-hand database management tools or traditional data processing applications.
>
> Utilities are already dealing with Big Data. A simple example is a utility with 100,000 meters that is taking 15 minute reads. One year of history for a few data items per meter will be in the terabytes (TBs), not considering any other data.
>
> [1]Gartner provides the following definition: 'Big Data are high-volume, high-velocity, and/or high-variety information assets that require new forms of processing to enable enhanced decision making, insight discovery and process optimization.'

The Data Analytics Problem

Analyzing new data sources such as those from AMI meters, substation IEDs, and distribution sensors can generate information to help electric distribution utilities improve operations by improving efficiency, reliability, performance, and asset utilization. However, potentially enormous quantities of data can easily exceed capability to transmit, process, and use the information effectively (sometimes called the 'data tsunami'). Similar data tsunamis have emerged in other industries, and new technologies have been developed to address 'Big Data.' Suitable mechanisms are needed to:

- Identify highest value data items from available data sources (filtering)
- Convert data to new forms of information (data analysis)
- Communicate insight to recommend action or to guide decision making, often using data visualization (visualization)

What is Analytics?

Analytics is the discovery and communication of meaningful patterns in data. Analytics can also be thought of as tools that identify unforeseen benefit and solutions from vast amounts of data. Analytics exhibit the following characteristics:

- Employ multiple and divergent data sources beyond the sampled raw data including weather, economic, operational conditions, census data and social media
- Techniques drawn from statistics, programming, historical experience, geospatial analysis and operations research
- Results are often presented in a visual and/or graphical manner

Figure 1 illustrates how utilities can use big data tools and analytics to discover new insights from complex data sources. As shown, multiple internal utility data sets (operational and non-operational), along with external data from outside agencies, can be combined with other large data sources that contain descriptions of complex relationship such as what can be found in Common Information Model (CIM) electrical connectivity data and Geographic Information System (GIS) spatial data, to create new insights and intelligence.

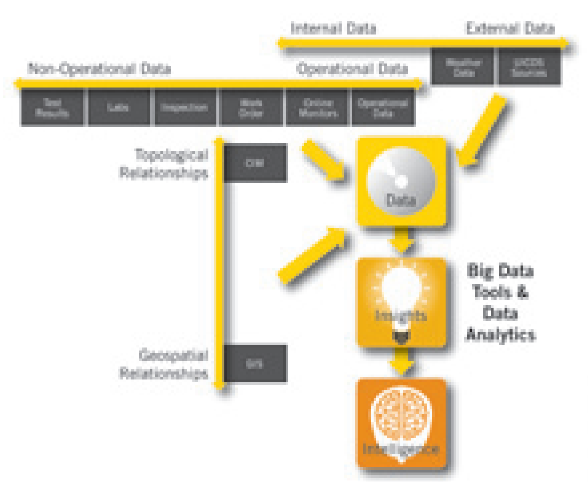


Figure 1: Creating Intelligence from a Myriad of Data Sources using Big Data Tools and Analytics

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[1] Douglas, Laney. "The Importance of 'Big Data:' A Definition. Gartner. *http://www.gartner.com/resid=2057415*

Applying big data tools and analytics provides the means for utilities to create new value from their smart grid and AMI platforms. Specific examples of grid analytics include:

a) Data analytics using AMI/MDM solutions
b) Outage management operational metrics
c) Emergency response data sharing
d) Device level asset intelligence
e) Optimizing distribution system performance through DMS applications

Big data and analytics are really more of a continuum and not a black and white concept. In other words, it is more of a road to take rather than something you are doing or not doing. In laying out a roadmap on how to get to big data and analytics, we recommend starting with basic analytics such as the AMI/MDM and outage management operational metrics before moving to big data analytics such as device level asset intelligence or cleaning up the engineering data used for fault location predictions.

It Starts With AMI Data

The AMI meter is not a meter, but a grid sensor providing energy, power and quality data at a frequency and latency to meet business needs. The Meter Data Management (MDM) system is responsible for ensuring the data's accuracy and completeness. Data analytics can only achieve its value if the source data is correct and available.

The design and implementation of AMI/MDM requires that the solution is able to collect and process more than just the data required for billing, but data from all the meter points all the time. Equally important, but often overlooked, the solution must be able to distribute the data to the systems which can use the data with a similar high performance and reliability. And, finally, the solution must be considered a real-time collection of sensors for utility operations. Unfortunately, many AMI solutions are initially designed, implemented and operated without this forethought and narrowly focus on collecting billing reads on a monthly billing cycle. So, the first step in data analytics is to ensure that the data generator is able to deliver the accurate, complete and timely information necessary.

The AMI/MDM solution is not just a data generator. Utilities are already doing data analytics using the tools that are part of the AMI/MDM solution to solve simple problems and provide meaningful results. Several examples of these analytic solutions are:

1. **Unauthorized Usage.** Several utilities are analyzing the meter consumption where there is no customer contract to identify premises where the consumer has moved in, yet has not notified the utility to initiate service.
2. **Theft Detection.** One utility compared the daily premise usage on a high usage day to identify premises using energy at a lower rate than similar premises to create a list of potential energy diversion cases.
3. **Service Problem Detection.** Some utilities are identifying services with an excessive number of outages, or blinks, to identify loose connectors or vegetation issues.
4. **High Usage.** Other utilities are comparing the consumption of individual customers against their historical consumption to provide a customer service by identifying potential service problems (e.g. water leak) or customers who may experience a high bill unexpectedly.

Although 'big data analytics' may appear to be a new concept, many utilities are already doing analytics using their AMI data and simple tools to extract value from their investment.

Outage Management Analytics are a Great Stepping Stone to Bigger Things

A good Outage Management System (OMS) is capable of consuming real time information from a variety of sources, analyzing it, prioritizing the work and providing its operators with a mechanism to respond to outages and perform efficient restoration. The OMS maintains a real time as-operated electrical model of the distribution network, tracking device operations in the field as well as the application of safety tags and temporary devices such as cuts and jumpers. As a result, outage systems are a rich source of data for both real time and historical distribution system analytics.

For real time processes, the analytics need to provide a comprehensive situational awareness enabling optimal management decisions based on operational priorities. The basic priorities are to: 1) address situations impacting public and employee safety first, next, 2) resolve issues that impact emergency management, medical and public good, and then 3) restore the largest number of customers as soon as possible by optimizing restoration taking into account system topology and geography, while 4) maintaining accurate records during the process for immediate use and after the restoration. There are a number of real time analytics which can support these goals, such as:

- **Outage Type Counts By Region vs. Crew Skill Set and Regional Assignments.** Comparison of the volume of work by region against the real time distribution of crews enables management to make informed decisions for more efficient distribution of crews to support restoration activities in different operating regions.
- **Estimated Restoration Time Metrics.** The trending of current estimated restoration times vs. actual restoration times and current outage durations allows quick identification of problems with aging outages before they occur. This can help improve customer satisfaction by reducing the possibility of providing inaccurate information to a customer.
- **Hourly Restorations/New Outages.** Analysis of outage trends by region and outage clearing device type can be used to determine if the restoration to new outage ratio is increasing or decreasing. This supports building processes for making informed decisions on calling in additional crews.

- **Data Entry and Validation Checks.** Often in the busy process of restoration, key pieces of information can be incorrectly entered. Analytics that generate a set of metrics for measuring performance can be used as a supplemental data validation method which helps ensure that data anomalies are caught and corrected early.

Historical analytics from an OMS – when combined with large amounts of data from other systems, such as an MDM – can be used to improve the accuracy of system restoration information. This analysis will support customer satisfaction efforts by identifying those customers who may be approaching a threshold for outage, can be used to replay utility responses to events, and to analyze for areas of improvement or proactively identify weakness in the system.

Outage management systems also provide valuable data that can be analyzed to improve asset utilization and drive preventive maintenance programs. When integrated with geospatial assets, maintenance management, AMI, and SCADA systems – the results of the data analytics become more valuable. This creates new opportunities to save money and track performance of system assets.

For example, device outage data can be combined with asset/location data to look for patterns of device failure that lead to changes in maintenance priorities. There are other possibilities such as:

- Relating momentary outages to asset and network issues
- Auditing construction and maintenance activities that lead to outages
- Tracing outage history to vendor quality control deficiencies
- Understanding the impacts of outage causes on revenue, regulatory compliance, and customer satisfaction

Emergency Response Data Sharing

For emergency response, advances in interoperability, such as the Unified Incident Command and Decision Support (UICDS) system from the U.S. Department of Homeland Security enable new capabilities for the sharing of public/private data. This interoperability and the new data sources enabled by UICDS improve situational awareness and enrich the data analysis both for utilities and for public authorities.

For utility operations, the additional data provided to the OMS through UICDS sources external to the utility from police, fire, emergency response organizations, and other utility operational systems, improves situational assessment and restoration. Transportation infrastructure status, potential or real hazard locations, location of available medical, fire and other resources all assist the utility field operations. For emergency response authorities, the utility data helps put the responders where they are most needed, keeps first responders aware of utility field operations and safety risks such as downed power lines, and focuses the utility restoration where it is most needed for public safety and disaster recovery.

Data sharing is further supported with the integration of the utility/public authority command structures. UICDS provides services to coordinate and share Incident Command System (ICS) data and operations, enabling the utility and public authorities to operate under a unified command.

Coordination of the utility outage detection and restoration processes with public authority incident management improves decision making, leading to better response speed, effectiveness, efficiency, and safety in emergency response.

Figure 2 illustrates the application of shared data to enable an integrated multi-source data approach to emergency management. This approach becomes increasingly powerful as more agencies and responders contribute to the overall situation awareness.

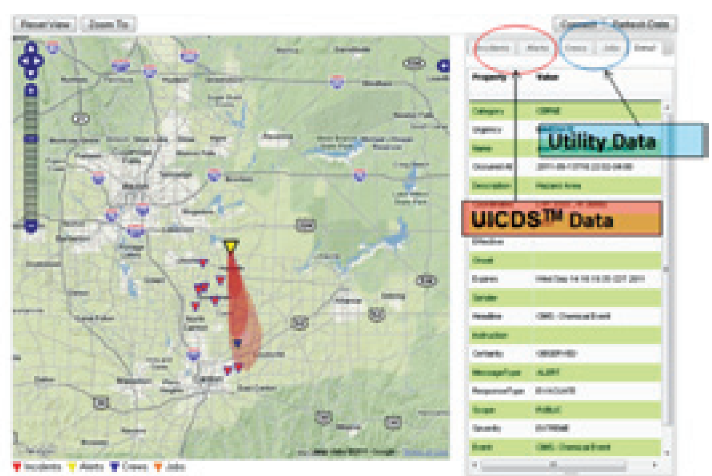

Figure 2: Sharing information between Utility and Emergency Response Organizations

Developing Asset 'Intelligence'

Big data technologies are the perfect tools for implementing device level asset intelligence. Asset management practitioners seek answers to the following questions:

1. What assets do I have and where are they?
2. Are these assets performing according to expected performance (utilization, availability, life time) criteria?
3. What is the present condition of the assets?
4. What are the expected risks of non-compliance with respect to established standards?
5. What optimal actions need to be taken to mitigate the identified risks?

Question 1 establishes the framework for the asset management space in terms of the physical nature, and location, of the assets. Questions 2 to 4 basically identify the right work to do and question 5 deals with doing the work right.

It is important to recognize that raw data can be found in various databases spread across the enterprise, and a common link enables the development of asset intelligence. A power transformer, for example, has related data in multiple databases: a Geospatial Information System (GIS) database to keep track of its location and positional attributes, an operations database that keeps track of electrical and non-electrical parameters and topology, a maintenance database that tracks maintenance information, an outage database that indirectly tracks performance, and a financials database that tracks associated costs.

Distribution transformer asset management is a good example of how big data and data warehouse concepts may be effectively combined to develop asset intelligence. Consider the following three metrics in the context of transformer sizing:

1. Number of times the transformer has been overloaded during its service life.
2. The ratio of total time the transformer was subject to overload to the total time in service.
3. The ratio of cumulative amount of loading greater than the transformer rating to the cumulative amount of total loading for the transformer.

The metrics provide a good understanding of the utilization of the transformer over the period of analysis. In this case, the total power flow of the transformer is calculated as the aggregation of all the customers that are fed off this transformer. The actual value of the individual customer loads comes from a big data source – the MDM. The association of the individual customers to the transformer comes from the topological model, typically shared between systems using the CIM. The decision to upgrade the transformer may be based on statistical characteristics of these metrics, calculated for all transformers in the service area.

Other metrics similar to those defined above may be used to quantify aspects of asset health, asset reliability and asset risk and to study the impact of various "what-if" actions as optimal strategies for asset management are devised.

Answers to the above questions may be obtained by identifying the number of times the transformer is overloaded (power flow exceeds nameplate, or rated, values) and the total time duration (in its service life time) of the overload. In case of both these metrics, a higher value means that the asset is over utilized, and a candidate for pro-active action to remedy the situation.

Optimizing Performance: Distribution System Management and Automation

Grid modernization is transforming the distribution system operations from a mostly manual, paper-driven activity to an electronic computer-assisted decision making process. New sensors, meters, and other IEDs provide increasing levels of automation and can supply a wealth of new information to assist distribution operators, engineers, and managers. This enables them to make informed decisions about improving system efficiency, reliability, and asset utilization, without compromising safety and asset protection.

One key operating requirement that can benefit from improved data analytics is Fault Location. When a customer outage occurs, distribution operators must dispatch crews to the affected area to locate the root cause of the outage and take the necessary corrective actions. Existing fault location methods, such as grouping customer 'lights out' calls and 'distance to fault' information from protective relay, can provide approximate fault location predictions. This narrows the portion of the feeder to investigate, but still leaves a significant portion of the feeder to investigate, especially if the feeders are very long and have numerous branches. By combining these existing data sources with voltage from distributed sensors and AMI meters, inputs from available faulted circuit indicators, and an 'as operated' model of the distribution circuit, fault location predictions can be significantly improved. The result is a much more accurately predicted fault location that dispatchers can take action on. The benefit is a more productive field workforce and faster service restoration for the affected customers. Figure 3 shows the output of a Fault Location (FL) application after most of the feeder has been re-energized (all except the faulted sections).

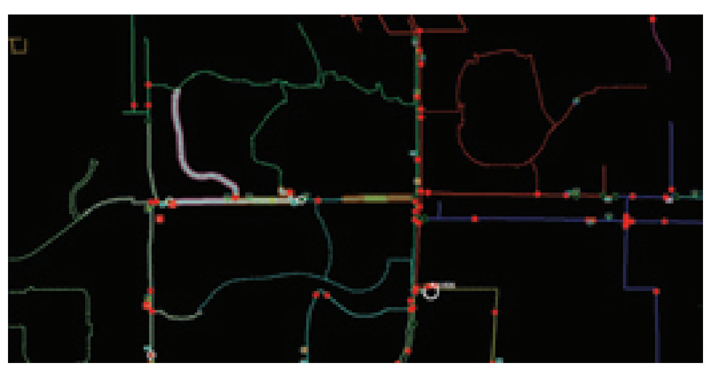

Figure 3: Output of a FL application, where fault locations appear as "halos."

Decision making at a growing number of electric distribution utilities is supported by a Distribution Management System (DMS) that includes advanced software applications for optimizing distribution system performance. Several key applications, such as Volt-VAR optimization, rely heavily on having an accurate model of the 'as-operated' state of the distribution network. Until recently, such models typically have questionable accuracy due to the lack of reliable measurements and errors in physical data extracted from the GIS. As a result, some utilities have been reluctant to place such applications in service, thereby missing an opportunity to optimize distribution system performance. Once again, data analytics may provide a solution to this problem. Data analytics that combine AMI load measurements with statistical load survey data can greatly improve the load models used by the DMS. Recently, researchers at the Electric Power Research Institute (EPRI) have shown that transformer phasing errors, a common modeling problem, and other modeling errors can be reliably detected by comparing AMI and substation voltage measurements. These analytics can greatly improve operator knowledge of the electrical state of the distribution system, thereby enabling the operators, engineers, and managers to take action to improve system performance without adding risk.

Many other examples for distribution feeder analytics exist, including detecting incipient faults and minimizing voltage regulator operations.

Summary

Analytics and big data tools are a new means available to utilities to discover new but useful patterns in multiple, large and diverse data sources. The recommended roadmap for getting to big data analytics starts with things that are not big data in the purest sense, such as AMI/MDM and outage management operational metrics. Once these more basic analytics are well in hand, the utility is ready to move to big data analytics such as, for example, device level asset intelligence or improving the underlying data used for fault location predictions. The roadmap is supported by integration within the enterprise, as well as outside of the utility industry, and through improved standards such as CIM.

About the authors

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Mark Wald is a Director at UISOL. He has over 25 years of experience in electric utility operations, including EMS network applications, energy markets, distribution applications, and IEC CIM standards. Mark is a member of IEC TC57 WG16, and is supporting the extensions of the CIM energy market model for demand response. He applies business intelligence to electric power operations, and is leading application of new standards for integration of utility and emergency operations. Before joining UISOL, Mark was at ObjectFX, Oracle, and Siemens (Empros). Contact Mark at *mwald@uisol.com*

Video Monitoring Solutions for Electric Utilities

Issues, Requirements and Examples

By E. Sotter Field Application Engineer, Systems With Intelligence Inc., G.P. Porciello, President, Systems With Intelligence Inc. and J. McClean, Vice President – Operations, Powerstream Inc.

Twenty-first century electric power utilities are faced with complex operational issues and challenges with respect to physical security of critical assets, particularly substations. These can include security threats to infrastructure and remote facilities, aging equipment and support structures, safety of personnel and the public, and overall rising costs due to unplanned maintenance, brownouts and even blackouts.

Video monitoring solutions are playing an increasing role in addressing these issues and, although typically used for security, they have the versatility to be used for a wide range of applications including equipment monitoring, asset management, and substation automation. In each case improved operations through automatic detection of events and other valuable information, can be obtained by automatically analyzing the content of the captured video through analytic software algorithms.

Challenges for Electric Utilities

Electric utilities provide a mission critical function and as such must ensure a reliable and stable flow of power at all times. Security threats, unplanned maintenance, malicious damage, and theft of materials are all increasing the operational costs for the utility in addition to increasing risks of brownouts and blackouts. These issues are further exacerbated by limited available personnel and unmanned facilities.

Energy providers are looking to technology more and more to help deal with these as there is currently a lack of automation systems that actually monitor the condition of critical equipment at substations and elsewhere on the grid. The industry has its own set of unique challenges, however, when deploying technology-based solutions. These include: finding solutions that are highly reliable and can withstand harsh substation environments; the high cost of equipment serviceability; implementing adequate connectivity solutions; interoperability with existing systems; and complying with evolving regulatory requirements such as NERC critical infrastructure protection (CIP).

The harsh substation environment is particularly problematic and requires specialized solutions. High levels of electromagnetic interference (EMI); wide temperature ranges; vibration and shock; and the presence of destructive pollutants all have the potential to interrupt or degrade performance of electronic equipment. As a result, design requirements must be more rigorous than those used for commercial grade installations. Although 'lesser' technologies used in such substations will work initially the inherent stresses will eventually surface and cause equipment failure.

Video Monitoring Applications

Two categories define applications:

1. **Security**

   Video monitoring is a key tool used to prevent and investigate theft, unauthorized access, vandalism, sabotage, terrorism or other uncontrolled damage to critical infrastructure. In recent years, high value metals found in electrical components are favorite targets and unmanned remote sites offer little obstruction to thieves. Apart from the theft, physical damage and destruction is often caused during the commission of the crime. Unplanned repair and replacement costs notwithstanding, brownouts and even blackouts can occur as the grid feed is 'taken.'

   A vital part of the intelligent video monitoring system is the capability to proactively alert personnel of an intrusion allowing security personnel to be quickly dispatched and any crime thwarted. Incidents are also recorded to provide investigators an opportunity to determine who perpetrated the crime after the fact.

   Complying with regulatory requirements, such as the NERC physical security standard aimed at controls to physically protect critical assets, is another area where video monitoring plays a vital role. Integrating video with access control provides the backbone of a physical security strategy that satisfies both NERC and general utility requirements.

2. **Asset Monitoring and Substation Automation**
Without adding personnel, improved efficiency and reliability of utility operations can be ensured by continuous and automatic remote monitoring of critical substation components. Early warning of impending equipment failures helps increase reliability without adding personnel. The chance of failures and downtime are reduced and asset lifecycles can be extended through preventive maintenance. The cost of protecting the utility's assets is negligible compared to the unit cost of the asset.

Intelligent video monitoring systems that utilize thermal cameras enables automatic detection of temperature increases in substation equipment. Through sophisticated video analytics algorithms for smart detection of anomalies, thermal signatures are analyzed and used as precursors to actual failures. 'Thermal rules' can be implemented to trigger automated alarm and email notification of possible issues. With the cost of thermal cameras coming down in recent years, automated thermal analysis has become a more cost effective tool in substation automation.

Integrating video into SCADA systems that are used to monitor and control an electric utility's operation is the next logical step. It provides enhanced understanding above and beyond that which can be obtained from graphical representations and numerical readouts. Visual confirmation of events or issues is particularly useful when personal safety is involved, such as verifying whether or not a breaker is open or closed before an operator enters an area.

Video Monitoring Solutions

A typical video monitoring solution utilizes components such as cameras, video recorders, servers, networking equipment, storage devices, and auxiliary equipment. Figure 1 illustrates a typical architecture for electric utilities and highlights the distributed nature of the utility infrastructure. This dispersed infrastructure raises a problem for video streaming as many substations are located in remote areas with no personnel on site and many times with only a low bandwidth channel for communications.

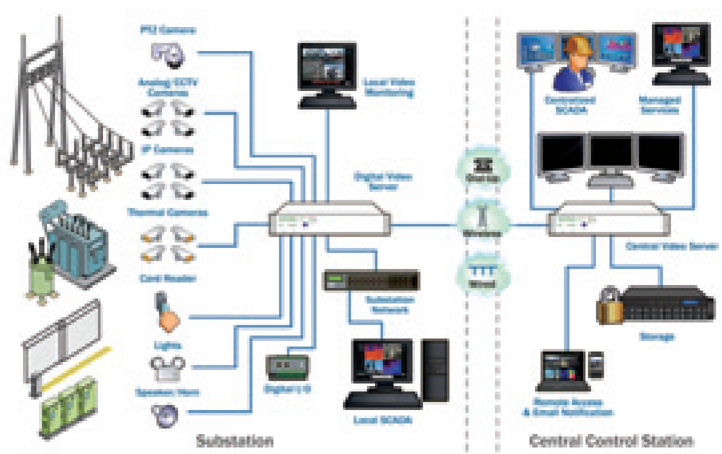

Figure 1: Video Monitoring Architecture for Electric Utilities

Digital Video Server. A digital video recorder (DVR) records video in a digital format to a disk drive or other medium. DVRs are typically located in close proximity to the camera(s) as they are generally directly connected to each other. With the proliferation of Internet protocol (IP) cameras, however, a direct connection is no longer required as video can be transferred over an IP network through switches and routers. These DVRs are referred to as network video recorders (NVRs).

The digital video server (DVS) is a new class of recorder that has all of the capabilities of the DVR and NVR, but makes it possible to integrate IP and analog cameras. Added functionality, such as digital I/O and SCADA can be incorporated into the DVS.

Cameras. Camera types fall into one of two categories – analog and IP, with analog currently being more widely used. Although both types capture live video in a similar matter, IP cameras incorporate the video encoding that enables transmission of live video directly over an IP-based communications network. These cameras are more complicated to configure but generally provide higher resolutions and additional features that enable users to remotely view, store, and manage video over the network. Analog cameras transmit the video with a direct connection, usually via coaxial cable, to another device that encodes the image.

Cameras can come in a fixed format, where the position and field of view is fixed, or as a PTZ (pan-tilt-zoom), which enables an operator to move the camera viewpoint around a wide area.

Video Management Software. Used in combination with either analog or IP cameras, video management software provides real-time and historical video monitoring, recording, and event management. Multiple cameras over many locations can be accessed via the software. Added functionality comes in the shape of installation and management tools for network video products, image enhancement capability, scheduling functions, and archive management. The software also handles the tasks of automatic notification of alarms or events through email or communications protocols. Automatic detection of events that occur within the video is made by using video analytic algorithms.

Video Analytics. In a typical monitoring application, a human operator has to constantly monitor a large array of video feeds for security threats or operational issues. As the number of cameras increases, information overload makes manual monitoring increasingly difficult. Analytics technology automates the monitoring and alerts the operator when unusual behavior or other events of interest are detected.

Video analytics are a set of software algorithms that analyses and extracts information from the contents of the video stream. These applications include:

- Motion detection, which automatically recognizes motion in a field of view
- Perimeter violation, or 'virtual tripwire,' that can monitor a fence line for any intrusion, such as a person jumping a fence
- Camera tampering to determine if a camera has been compromised
- Loitering to determine if people stay too long near a restricted area

This technology is also increasingly being used in substation automation as a feedback into an operational control or monitoring function.

Storage. Video monitoring systems that record activities and events require a significant amount of storage space, especially if archiving of the material is required. Reliability and scalability are key issues with typical solutions using a combination of local storage on a DVR as well as network attached storage where additional space can be added and expanded to terabyte storage systems.

Auxiliary Components. In some cases, video monitoring systems employ additional components to enhance or add new capabilities to existing operations. Access control and physical motion detection are used in conjunction with the video system to provide a completely integrated security solution. Cyber security concerns can also be addressed be incorporating intrusion detection systems and firewalls with the monitoring function.

Design Guidelines for Electric Utilities

When solving issues or improving operations within a substation, it is imperative that the utility selects the right technology for the application. The following provides high level design guidelines to consider:

Architecture

One of the most important considerations with video monitoring solutions is understanding the deployed architecture or topology. Figure 1 illustrates the distributed nature of the utility infrastructure.

Typically, most commercially available solutions utilize an architecture where there is one central server and cameras are connected – either directly or through an IP network. Oftentimes, it is assumed that there is unlimited bandwidth and that the communication infrastructure is not a limiting factor. This is generally not true for communications to and from a remote substation.

For utilities with multiple remote sites, each with different bandwidth capabilities, utilizing a centralized architecture results in a huge limitation as video competes for available bandwidth with critical network traffic 100 percent of the time. Requiring a large amount of bandwidth limits the number of users that can access the system and possibly shutting down the recording process if there are any problems in the network.

In a distributed architecture, cameras and at least one video server are located at each substation. The benefits of this approach are:

- Allows constant high resolution recording
- Optimizes bandwidth by only delivering video 'on-demand' over the network
- Is not affected by disruptions in the network
- Allows for multiple simultaneous users

In addition, a distributed architecture more easily allows the user to optimize the configuration of the architecture to the available network communication infrastructure while maintaining high fidelity in recording and long-term archiving. It also more directly matches the distributed nature of the utility infrastructure and reduces the dependency on available bandwidth.

Harsh Environments

The harsh substation environment presents particular challenges for utilities. Deployed technology solutions require specialized hardware components and packaging and software systems must be designed with ultimate robustness and reliability in mind. To ensure reliable and proper operation within the substation environment, equipment must meet or exceed rigorous specifications such as IEC61850-3 and IEEE 1613. Hardware must be able to operate in a temperature range of minus 40 degrees Celsius to plus 85 degrees Celsius without the use of fans while utilizing industrially rated power supplies – ideally in dual power supply configurations. In addition, communications using fiber interfaces are more reliable and immune to EMI than copper.

Cameras

Design considerations for cameras include:

a) Choosing between analog and IP cameras – while the trend to IP cameras continues, analog units can be suitable where cost and ease of use are of primary concern.
b) PTZ cameras offer increased flexibility but at a higher cost.
c) Camera resolution is determined based on the amount of detail needed in the scene for the specific application.
d) Lens choice which is based on the required field of view, low light level performance, depth of field, and overall image sharpness.

As most camera installations are in outdoor environments protecting the equipment is vital. Like other hardware components in the substation resistance to EMI, meeting substation design specifications, and the ability to operate reliably in a wide temperature range are required. Ingress Protection rating is also important with a minimum of IP66 (dust and water tight) recommended.

Since no two substations are identical, the selection of cameras and their placement will always be site specific.

Software

All video management software contain the basic functions to provide real-time and historical video monitoring, video recording, event management, and other support and management functions to access and configure multiple cameras over multiple remote locations. There is, however, a difference between video management software designed for commercial security applications and industrial automation environments. Features, such as industrial protocol support for easy integration into SCADA systems, ability to control digital I/O for use in an automation application, and the ability to integrate other automation equipment through various serial or communication interfaces should be available.

Software designed for industrial applications are generally more reliable since the critical nature of the application is taken into account during the design process. In particular, the available video analytic functions should be designed to work in outdoor and uncontrolled environments that are the norm for substation applications. In addition to automatic identification of events for physical security, video analytics algorithms for utility substation automation functions should also be available.

Bandwidth/Storage Optimization Techniques

Design considerations related to bandwidth and storage are very important especially for a distributed architecture. Configurable parameters related to video format, resolution, frame rate, and encoding quality are required to help optimize the implementation. Any deployed solution should allow flexibility in adjusting these parameters and should allow for the use of multiple video channels with settings for different users or functions, such as recording at a high resolution while simultaneously streaming at a lower resolution. Additionally, the effective use of video analytics can be used to reduce network bandwidth requirements. For example, automatic detection of events can be used to send video over the network only on defined 'triggers,' i.e. motion. Finally, the use of local storage and recording to reduce overall bandwidth requirements, with the possibility of scheduling the archiving of video to times when network usage is low, should be considered.

Conclusion

Video monitoring systems have the versatility to be used for a wide range of applications within electrical substations, power plants, and other critical infrastructure. Although typically used for security, this paper has shown that video can be used in new and innovative ways for equipment monitoring, asset management, and process control. By using video effectively, improved operations and valuable information can be obtained by automatically analyzing the content of the video. This will ultimately have the effect of optimizing utility operations, while reducing downtime and costs.

Given that substations are the most remote points of any grid (smart or otherwise), the real question that the utility should consider is not whether to implement a video monitoring system, but rather what is the most that can be obtained from it.

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THE BIGGER PICTURE

BY MAURA GOLDSTEIN BAKER BOTTS L.L.P.

A Lean, Green Fighting Machine?

Part 1: The Regulatory Risk Posed by the Army's Renewables Initiative

On March 15, 2012, the United States Army ("Army") released a draft request for proposal for 'up to $7 billion in renewable energy sources,' a massive procurement to be overseen by the Energy Initiatives Office Task Force ("EITF").[1] The EITF was established by the Army to focus on 'large-scale renewable, almost utility-scale renewable projects' that will provide alternative forms of energy to 'offset all or part of the energy needs of a permanent installation.'[2] These initiatives are intended to support the Army's net-zero strategy, whereby an Army installation is to produce as much energy as it consumes, its plan to enable installations to 'island' in the event of power grid failure, and its efforts to meet its renewables mandates.[3]

The final 'Request for Proposal for Large Scale Renewable Energy Production for Federal Installations' was issued on August 7, 2012 in the form of an Indefinite Delivery Indefinite Quantity Multiple Award Task Order Contract ("MATOC"). [4] The scheme outlined in the MATOC is one that relies on the authority of the Army under 10 U.S.C. §2922a ("§2922a") to enter into contracts with terms of up to 30 years to procure energy ("power purchase agreements" or "PPAs") as a means of attracting investment in greenfield renewable power projects to be built on-base. Applicants will be pre-qualified by the Army and then will receive task orders inviting bids on identified project opportunities in each of the areas of wind, solar, geothermal, biomass and other alternative energy technologies. The expectation is that a contractor that is awarded a task order will enter into a PPA with the Army, and this long-term payment commitment from the Army will enable the contractor to raise the private sector financing necessary to construct and operate a power plant that will produce the renewable energy required to satisfy project PPA obligations for 30 years.

This large-scale adoption of a long-term PPA approach to renewable energy procurement by the Army has caused great excitement because it represents a material change in Army energy procurement practice and promises to stimulate a large volume of investment in the renewable power sector. However, the novel approach has also generated concerns amongst both those already engaged in supplying energy to Army installations and those new to the scene. A review of the complex legal issues underlying the Army's renewable energy initiative demonstrates that these concerns are valid. If not addressed and resolved by the Army from the outset, legal uncertainties have the potential to dampen private sector interest, slow EITF momentum and result in higher renewable energy costs to the Army. This Part 1 explores the risk posed by jurisdictional conflicts between the Army and state energy regulatory authorities in relation to a §2922a PPA.

The project regulatory risk that arises in connection with a §2922a PPA is, perhaps, best captured by a recent 'déjà vu moment,' when the Army ran headlong into a decades long conflict between federal procurement law and state law governing the electric utility industry in connection with Fort Bragg's plan to comply with the Army's net zero strategy. [5] A key part of the plan is to attract private investment for the construction of renewable generation resources at the installation by utilizing authority under §2922a to offer long-term PPAs. The plan was stymied, however, by state law that makes plain that an entity generating and selling electricity to or for the public for compensation is a 'public utility' and subject to public utility regulation under North Carolina law.

While the North Carolina Public Utility Commission staff seemed sympathetic to the notion that §2922a confers upon the military the authority to enter into a long term power purchase agreement, they pointed out that the statute is silent as to the status of the contractor, and apparently felt compelled to remind the Army that the Federal Energy Regulatory Commission (FERC) 'has ceded regulation of retail electric sales to consumers *to the states*.' A white paper published by the U.S. Department of Energy (DOE) Clean Energy Application Center (CEAC) for the region reported this and the unfortunate 'barriers' posed by state law to the Army's ability to attract investment in renewable power plants, and then went a step further by invoking the Supremacy Clause of the U.S. Constitution to remind readers that federal statutes such as §2922a are 'the supreme law of the land.' The appropriate balance between state and federal jurisdiction raised in this example remains unclear. What is clear, however, is that a project developer of a renewable power project at Fort Bragg could easily get caught in the middle.

The recent application by the Army of §2922a is without precedent. To attract the scale of private capital investment required to fulfill its renewables mandates, the Army needed to offer long-term PPAs. The problem was that a PPA of more than 10 years' term could not be supported by conventional Army energy procurement contracting authority.

The conventional approach to energy procurement by government is embodied in a Utility Service Agreement. Under this sort of contract, the military is a retail customer generally agreeing to a year-to-year (or a maximum 10 year term) contract for electricity supply at retail rates. The generation mix, as well as transmission and distribution arrangements in respect of the electricity the Army purchases, is generally a function of the local regulatory environment; and options to ensure that a significant portion of energy purchases meet the idiosyncratic requirements of the Army's renewables mandates are limited. As a result, the Army needed a new way of doing business with the private sector.

It was in this context that the Army roused §2922a PPA authority from nearly three decades of dormancy. §2922a seemed an unlikely candidate to serve as the foundation for the launch of $7 billion in procurement under the MATOC. It had been adopted in 1982 in connection with a bill addressing the construction of military housing, but apparently never employed. However, on its face, §2922a seemed to offer a straightforward solution to the Army's renewables conundrum by providing broad authority to enter into 30 year power purchase agreements, as follows:

Contracts for energy or fuel for military installations

(a) Subject to subsection (b), the Secretary of a military department may enter into contracts for periods of up to 30 years—.

(2) for the provision and operation of energy production facilities on real property under the Secretary [of a military department's] jurisdiction or on private property and the purchase of energy produced from such facilities.

The real complications associated with §2922a PPAs are outside of the statute. One of the complications that a private party entering into a §2922 PPA should be alert to is the potential for conflict between the Army's proposed PPA and the law of the state in which a power project is to be located. This issue was the subject of years of litigation and, ultimately, legislative and regulatory action to require federal agencies to defer to state law when buying electricity. A federal statute (40 U.S.C. §591) commonly referred to as '§8093' states that '[a] department…of the Federal Government may not…purchase electricity in a manner inconsistent with state law governing the provision of electric utility service…'

When §8093 was adopted in 1987, there was already a dispute underway in the Eighth Circuit regarding the reach of the military's procurement practices relative to the states' regulatory power over utility customers. *Black Hills Power & Light Co. v. Weinberger* ("Weinberger") concerned Black Hills Power & Light ("Black Hills"), a state utility with a utility service territory in which Ellsworth Air Force Base ("Ellsworth") was located. Black Hills raised a challenge to Ellsworth's attempt to procure its overrun electricity needs through a competitive bid process.[6] The Eighth Circuit, finding for Ellsworth, relied on the doctrine of 'federal enclaves' to conclude that the Supremacy Clause's grant of exclusive legislative power to Congress with respect to federal entities bars state regulation unless there is 'clear and unambiguous' Congressional action authorizing state regulation of a federal entity.

Congress passed §8093 before the Eighth Circuit issued its decision in Weinberger, however the court reasoned that the legislation did not alter its analysis, explaining that Congress had adopted §8093 out of concern for the particular situation in which a federal facility 'abandons' a local utility system, and that the facts of Weinberger raised no such concern.

After the passage of §8093, Black Hills renewed its challenge in *West River Elec. Ass'n, Inc. v. Black Hills Power and Light Co.* ("West River"), arguing that §8093 supported its previous claim.[7] The district court reasoned that §8093 was not a 'specific grant of jurisdiction' to the state allowing it to overcome the Supremacy Clause. On appeal, the Eighth Circuit did not disturb its prior conclusion that Ellsworth was a federal enclave and affirmed the district court's holding that Congress 'has not provided the necessary authorization to defer its exclusive jurisdiction over Ellsworth.' It found that §8093...did not evince a 'clear and unambiguous declaration by Congress to amend the extensive and carefully-crafted body of federal procurement law.'

The most recent discussion of §8093 by a federal court appears in *Baltimore Gas and Electric Company v. United States* ("BG&E"). The validity of a separate Act allowing for privatization of utility services on military bases was before the United States District Court for the District of Maryland in BG&E.[8] The court adopted a Government Accountability Office ("GAO") decision, which found persuasive a legal opinion (the "DOD Opinion") prepared in 2000 by the Office of General Counsel of the U.S. Department of Defense ("DOD"), that the section applies only to the purchase of the commodity electricity, and not to the conveyance of an electricity distribution system. In the course of its review, the court stated that §8093 stands for the proposition that 'federal statutory provisions and regulations require that the Army must follow state law and regulations, including utilities regulations and franchise agreements, in its purchase of the commodity electricity.' The court did not attempt to square its contrary characterization of §8093 with that of the Eighth Circuit in West River.

Advocates for exclusive federal jurisdiction in relation to projects awarded under the MATOC have a strong legal argument that West River is still good law. However, those who believe that state regulatory powers should prevail would make the counter-argument that the lower court in West River distinguished that specific case from application of §8093 on the narrow grounds that the Ellsworth solicitation was not within the scope of Congress's concern to 'protect utility abandonment by their federal customers.' In contrast, the Army's stated intention underlying the MATOC is to replace the electricity that installations presently purchase from the local utility. In addition, BG&E can be construed as a more modern statement of the meaning of West River; and, indeed, the Federal Acquisition Regulation, a comprehensive set of regulations governing federal procurement, now incorporates the limitations imposed by §8093.

Whatever the exact scope of §8093, it does seem that, as a practical matter, the Army has admitted to its application to Army electric power purchases and, for purposes of the MATOC, is relying on a statute that happens to be an exception to §8093 in the form of §2922a. §8093 expressly provides that it 'does not preclude the Secretary of a military department from entering into a contract under [§2922a]...' Thus, it would appear that, even if to do so would be inconsistent with state law governing the provision of electric utility service, the Army may enter into a §2922a PPA and dispense with the complications of §8093 jurisprudence described above.

Unfortunately, however, this is where the next level of complexity begins, because even as the §2922a exception informs the Army of its position relative to state regulatory law, it is silent as to the position of the Army's PPA counterparty. We are left to wonder how a contractor is to be regulated, if at all, in a world in which §8093 does not apply. The question becomes even more pressing in the context of a specific project that is interconnected with the grid and, particularly in the case of intermittent resources such as wind or solar, is an integrated piece of a larger puzzle that relies on back-up energy from the local utility.

As it turns out, this very question was addressed, at least indirectly, in West River, BG&E and the DOD Opinion. Not surprisingly, the inference that may be drawn from each regarding federal and state jurisdiction is different. One may reasonably conclude that the West River court would uphold exclusive federal jurisdiction (as it did before the passage of §8093), while inferring that the BG&E court would apply a combination of federal and state interests. Arguably, however, it is the DOD's own Office of the General Counsel that has best explained the balancing act that would result.

The DOD Opinion, in its analysis of federal and state jurisdiction over utility services, noted that, whereas federal laws trump states laws when Congress has 'left no room' for state regulations, the answer is 'less clear-cut where state and federal laws do not directly conflict.'[9] In such cases, the DOD Opinion maintains, the Supreme Court has balanced federal policies against whatever safety, economic or health concerns the state could articulate. On this basis, the DOD Opinion concludes with respect to the specific circumstances under review that the state could not impose a preclusive license requirement on prospective contractors, but could regulate the operation of contractors to protect state policy interests.

In the case of a contractor under a §2922a PPA, it would appear that a project's exposure to regulation as a utility (or as another form of entity based on the degree and structure of regulation in the relevant state) will depend upon the specific characteristics of the project, the objectives of the federal policy, the prevailing local energy regulatory regime, the safety, economic, reliability or other regulatory measure proposed by local regulatory authorities and the degree to which it would conflict with the federal objective in each case. From a developer's perspective, this represents uncertainty and, unless state and federal authorities reach a consensus on a mutually acceptable regulatory regime from the outset, this uncertainty will pose an impediment to investment and financing.

Although the Army has generally indicated in the midst of the MATOC fanfare that it has been working with local utilities in connection with its preparation of project opportunities, it has not engaged in a direct discussion of §2922a PPA-related state and federal jurisdictional issues with prospective participants under the MATOC or in connection with other PPA opportunities at Army bases. To the contrary, in the most recent bid documents issued by the Army, bidders are required to represent and warrant that they will not be regulated as utilities under relevant state law.

If the Army does not take early and transparent action to acknowledge that there are open regulatory questions requiring resolution on a project-by-project basis by means of direct engagement between the Army and local regulatory authorities, then it risks losing momentum in its efforts to satisfy its renewables mandates. Prospective participants receiving requests for proposal that do not adequately identify legal risks or reflect efforts made to mitigate such risks will be discouraged by uncertainty and high transaction costs. Local regulatory authorities with limited opportunity to reach a consensus approach to complex jurisdictional issues are more likely to cause delay. In addition, of course, if legal risks are left unresolved, and the potential for litigation persists, then the Army can expect to pay a risk premium for those projects that do proceed.

The Army's renewable energy initiative represents an historical opportunity in the U.S. to achieve government infrastructure objectives using project development and finance methodology. If the Army takes the lead to address the regulatory concerns of all stakeholders in this new way of doing business, the initiative may serve as a powerful example of public-private and federal-state partnership success.

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With William T. (Tim) Shaw
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SECURITY SESSIONS

So, why can't I do that??

Watching the NERC Critical Infrastructure Protection (CIP) standards evolve over the past few years, and seeing all of the ongoing discusssions in the various on-line blogs about what may or may not meet with NERC compliance, leaves me with the belief that there are still many issues that have not been properly or adequately addressed. When the 'rubber meets the road' during the implementation of a cyber security program, that is when you run into the issues that don't seem to fit into the strictures of standards developed by well-intended people who don't do this for a living. We also continue to see the collisions between what corporate IT thinks is a best practice and what NERC thinks is a better practice. Let's look at some examples.

One of the common practices in big corporate IT is to outsource manpower-intensive activities in order to minimize 'head count' (a cute accounting term for staffing level) and possibly to move liability and risk to an outside organization (a strategy called 'blame-shifting'). A common example is the outsourcing of the IT help desk (irritating at times, but not necessarily a CIP compliance issue).

A more pertinent and growing example is outsourcing the 24/7 monitoring of the corporate network and the security mechanisms such as the firewalls, critical servers, host intrusion detection systems (HIDS) and network intrusion detection systems (NIDS). Why not let low-cost, but well educated and technically proficient, people in Bangalore watch over your critical infrastructure? You can set up a virtual private network (VPN) connection over the Internet and route all the alarms, alerts, and logs to their attention and inspection and at half the cost of staffing this function yourself. Makes good business sense, but does it make good CIP sense?

Recall that the basic purpose for producing the CIPs was to get electric utilities/entities to provide adequate cyber (and physical) security for their critical cyber assets (CCAs) in order to protect them from attack. A basic tenet of that requirement is the establishment of an electronic security perimeter (ESP). Although there have been lots of arguments over what creating an ESP really means and what constitutes a penetration of that perimeter, I would hope that everyone would agree that the intent is to prevent unauthorized, uncontrolled, and unmonitored (and potentially malicious) communications between CCAs and 'external' systems. A major aspect of creating an ESP is the placement, configuration, monitoring, and maintenance of boundary protective devices, i.e. firewalls, at all ESP penetration/access points. Let's ignore asynchronous, serial, low-speed [non-IP, non-Ethernet] communications for the moment as they present a different challenge and may not count. Let's also ignore wireless communications (cellular, IEEE 802.11 and Bluetooth) for the moment as they provide a whole different range of special challenges.

CIP-002-5 defines bulk electric system (BES) cyber system 'Associated Cyber Assets' and includes Electronic Access Control or Monitoring Systems (EACMS) in that category. IDS/IPS and ESP boundary firewalls would seem to fall under that definition and therefore they would need to be protected against compromise. The CIPs address requirements for verifying the trustworthiness of your personnel – especially those who are involved in the use, support, and maintenance of the CCAs. The CIPs also address the basic physical security requirements to protect as well as to limit and control physical access to the CCAs. The problem with out-sourcing the monitoring, and possibly the administration, of your network architecture and protective/detective assets, especially to a foreign organization (particularly in a country where a lot of people don't like the U.S.), is that you can't guarantee that they meet the same level of cyber and physical security as you do. Problems can arise even if you 'include language in contracts that requires adherence to the Responsible Entity's Interactive Remote Access Controls', as stated in CIP-003-5 requirement R1, paragraph 1.2.

Have you ever signed a contract with a vendor and then discovered that they failed to actually live up to the all of the elements of that contract and associated P.O., at least as you interpreted them? I know that I have, and they were mostly US firms. You might provide yourself with some legal/regulatory blame-shifting by including appropriate contract language, but in reality you really can't be certain that you are not opening up a very dangerous attack pathway directly into your ESP and your CCAs.

If you do decide to do this anyway you must open up a bidirectional access point in your ESP in order for it to work. Even if that connection is VPN protected, and there is no known attack methodology for compromising that connection today, that doesn't mean that one won't be discovered in the future. Lots of cyber security mechanisms believed to be unbreakable in the past have fallen to technology advances and new technologies – just ask the IEEE folks who came up with wired equivalent privacy (WEP) or the Government folks who gave us DES.

Another common corporate IT practice is the centralization of user authentication and security policy management, often through the deployment of technologies such as Microsoft's Active Directory© (AD) servers. These are typically not located within your ESP. This strategy allows corporate IT to 'push out' policy changes, including user account changes/removal to all of the computers and servers across the corporate WAN and to centrally manage user ID/account verification. That is very efficient from an IT manpower point of view, but if this approach is integrated into EMS/SCADA systems or plant DCS systems then you potentially create a cross-WAN, ESP boundary crossing communication requirement essential to the function of those automation systems, which are 'inside' your ESP. Those AD servers may or may not have adequate cyber and physical security and thus may not meet the requirements of being inside a separate, but linked ESP. Corporate IT usually dislikes allowing such things to be out of their control, but it is possible to have a duplicate AD server positioned within your ESP and then all you have to deal with is the periodic updates sent to this server from the master AD server. That kind of message traffic is actually pretty easy to run through an ESP access point firewall and then monitor with a NIDS. But you have to talk corporate IT into letting you set things up that way, which goes against their world view of best practices.

To take things even further, corporate IT has embraced the use of virtualization and thin-client architectures so they have control over the applications you are allowed to use and so they can rapidly provision additional virtual desktop PCs and application servers. It always seems as if they never plan for enough server and network bandwidth (probably as a cost saving measure) and so the responsiveness of your personal thin client can vary dramatically through the day/week. Of course that is because the workload on an IT server will peak and drop as people first arrive at the start of the day, take coffee and lunch breaks and then head home at end of the day. IT often plans their server processing power and network bandwidth to support the median or average load, thus things are slow first thing in the morning and speed up over lunch. Having been forced to endure working in this kind of 'IT paradise' for several years, I have often been reminded of why using centralized computer control was dumped when distributed control architectures were eventually developed. I have lately seen electric utilities where the SCADA/EMS group was placed under the management of the IT organization. As a result the next SCADA system upgrade/replacement was also a conversion to a thin-client architecture with the servers being controlled by IT and the control room operators of the transmission system being given web browser access to their system – essentially treating the SCADA/EMS system as just another corporate application. The servers were physically owned, managed, and controlled by IT. Again, this makes it very complicated to establish an ESP – let alone a physical security perimeter (PSP) – particularly when a good portion of the CCA(s) that need to be protected are 'virtual'.

Oftentimes, a gaping hole is created in the in the cyber security/electronic perimeter of many organizations due to the incautious/insecure use of portable electronic devices, such as laptops and tablets and the use of removable/portable computer media like the ubiquitous USB 'thumb drive' or DVD/CD platter. I can't remember the last time I was in a SCADA system or DCS system control or computer room and didn't see a laptop PC, USB thumb drive, cell phone or CD/DVD platter (not to mention less-often seen things like MP3 players and digital cameras). Because critical systems are often isolated (air gapped) or given very strictly controlled and limited communications connectivity to networks and other systems (at least one would hope so) the only reasonable way to transport patches, software updates, configuration files, collected data and the like is via portable media or portable devices that support file systems and storage. The problem is that these same media and devices can also be used to deliver malware; as the Iranians found out when Stuxnet was introduced into their control systems.

So, on one hand it is almost essential to be able to use portable devices and media with your critical automation systems and digital assets, but on the other hand this can lead to self-inflicted cyber attacks if you don't do it properly. Is there a safe way to use these things?

First it's important to recognize that there is a major difference between passive media, such as a tape, a floppy disk, a CD/DVD platter or a dumb USB storage device and an electronic device that has a processor, a file system and field-alterable stored programming that might include a laptop PC. Passive media has no ability to actively hide its contents from virus scanning tools. If known malware is loaded on passive media it is probably going to be identified via a comprehensive malware scan. I say 'probably' because some evaluation testing performed on several of the more popular virus scanning utilities showed that the detection of more recent malware is not 100 percent reliable. The reliability gets much better when several scanning packages are used and the packages are kept current with vendor updates. The secret is to run the scanning tools on a bare-bones, well-hardened, and properly patched stand-alone system, just in case there is dangerous malware on the media that attempts to compromise the scanning system itself!

On the other hand a severely compromised device, such as a laptop PC that has been infected by a modern rootkit, has the ability to hide malware from virus scanning tools, even making entire directories invisible, so that the likelihood of successful malware detection is low to non-existent.

In-between those two extremes are less-capable electronic devices with differing levels of vulnerability to malware infection and being able to be used as a delivery mechanism. Modern cell phones are probably the most dangerous devices in this group, particularly because of Bluetooth wireless networking support. But any device with USB connectivity and a mountable file system has the potential for being used for malware delivery. You normally have very few options for performing malware scanning on such devices. Worse, if connected to a Microsoft Windows computer that has universal plug-n-play services enabled (the default setting in older Windows distributions) such a device can install a rootkit in the form of a device driver.

You have a reasonable chance of avoiding infection if you establish and maintain good procedures for media scanning and use only passive media. You can even allow portable devices to be connected to your CCAs if you establish strict procedures to ensure that such devices don't leave your control and are not connected to insecure networks, like the Internet, or to systems outside of your control. There are some best practices for this and this is one case where corporate IT may actually have the 'right stuff' to keep you protected and your ESP secure.

Of course it is possible to find strategies that can both satisfy the corporate IT folks and meet the NERC CIP specifications, but that requires that IT be willing to compromise and accept that their best practices are not always industrial automation best practices. It may also require taking an approach that isn't the lowest cost way to do things. Getting management buy-in may be the biggest stumbling block of all, especially if they see the CIPs as just a bunch of stupid regulations that produce wasted time, effort, and funding to protect against a threat that isn't real. There are ways to explain the cost-benefit justification of reasonable cyber security, but that will have to be the subject matter for a future column.

ABOUT THE AUTHOR

Dr. Shaw is a Certified Information Systems Security Professional (CISSP), a Certified Ethical Hacker (CIEH) a Certified Penetration Tester (CPT) and has been active in designing and installing industrial automation for more than 35 years. He is the author of Computer Control of BATCH Processes and CYBERSECURITY for SCADA Systems. Shaw is a prolific writer of papers and articles on a wide range of technical topics and has also contributed to several other books. He has also developed, and is an instructor for, a number of ISA courses. Dr. Shaw is currently Principal & Senior Consultant for Cyber SECurity Consulting, a consultancy practice focused on industrial automation security and technologies. Inquiries, comments or questions regarding the contents of this column and/or other security-related topics can be emailed to *timshaw4@verizon.net*

Guest Editorial

What's in Store for 2013?

Making Sense of all the Predictions

By Mark Madden, Regional Vice President for Utility Markets with Alcatel-Lucent's America's Region

This time of year is always a fitting occasion to make predictions and resolutions for the year that lies ahead. Analyst firm IDC has come out with its top 10 predictions for North American utilities in 2013[1] while Zpryme published their December Smart Grid Index[2] which surveyed industry players on, among other things, their intentions and priorities for 2013.

It's kind of obvious that the effects of Hurricane Sandy figure prominently among the predictions. The scale of Sandy was unprecedented, and it seems the resulting debate has been similarly proportioned. But the aftermath of a natural disaster is always a confusing place to be and so it's taking a little time for thoughts to be collected and opinions to settle.

With more than 8 million people affected by power outages due to Sandy, some of whom remained without electricity for weeks, the debate about what our industry needs to improve has been pretty fierce. While some utilities certainly fared better than others, I don't think that's necessarily a reflection on anyone's performance; rather on the vital role that utilities play in their communities. Regardless, the expectation – and therefore some of the major predictions people are making for 2013 – is that we will see an increased focus on ways of ensuring that the next major storm to strike our shores does not have the same impact.

Away from Sandy, another recurring prediction for 2013 concerns cyber security. The Senate may have recently rejected the Cybersecurity Act of 2012 but it most definitely hasn't gone away for good. And even so, both the North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) regulations and the National Institute of Standards and Technology Interagency Report (NISTIR) 7628 both have plenty to say on the subject. In the last edition of Electric Energy T&D, there was an excellent guest editorial[3] on the subject by Eric Byres at Belden Inc. And in October the US Secretary of Defense, Leon Panetta, weighed in on the subject in a speech at the Intrepid Sea, Air, and Space Museum in New York, likening the threat to U.S. critical infrastructure as an impending "Cyber Pearl Harbor." Some recent research, again from Zpryme[4] , further indicates that cyber security will continue to be a headline grabber for utilities in 2013.

There's a third prediction that I've seen crop up on more than one pundit's list for 2013, and that is a focus on operational efficiency. Like the predictions following Sandy, there's no great surprise in that one. Operating costs have been a priority for many years and there is significant pressure on the industry to update and evolve our critical infrastructure to become more cost efficient and extensible in order to avoid, or at least delay, the need to build the really expensive things like power plants and transmission lines. There does seem to be a general consensus that 1) technology will be increasingly important for creating efficiencies, and 2) utilities will be bolder about investing in these new technologies in order to reduce the inefficiencies of the old.

Finding the thread

Call me crazy, but this predicting business looks so easy I thought I'd give it a go! Now, I am a telecoms guy, so naturally I'm coming at it from that perspective. But it seems to me that there's an obvious common thread to all the predictions I've already mentioned, and that thread is telecommunications. I'll reveal my 2013 prediction at the end of this article, but first I'll take you through my reasoning. Much of the debate post-Sandy has been about the smart grid. Did it fail us? Did it help? Have we done enough? Is it time for something new? There appear to be three camps:

1. The hard-liners, who say that smart grid can't save us from another Sandy and want to see supply physically hardened and protected through actions such as burying cables or cutting back trees around overhead lines.
2. The intellectuals, who believe that pushing on with smart grid deployments, i.e. increasing the intelligence and automation, will enable us to isolate outages at a more granular level, both reducing the number of people affected and speeding up recovery times. Simply put, if we can broadly deploy intelligent circuit reclosers and rerouting technology sitting every few houses rather than every few blocks, any interruption in supply can be limited to just those few houses rather than entire neighborhoods. Similarly, a central control room would be able to pinpoint where an interruption occurs down to a few yards or so, so dispatching a team to deal with it is faster and more efficient.

3. The alternativists who want to diversify supply with alternative and distributed generation, such as adding micro and renewable sources to the grid, or self-sufficient capabilities that can operate independently from the grid if necessary, such as New York University's cogeneration[5] capability.

I guess there's a fourth camp, which includes me – the pragmatists. That none of the above approaches on their own will be right for every utility and that a combination of all of them will be necessary.

Adding renewable requires extending communications connectivity to the farthest edges of the grid

The link to communications on all of these is strong. If we begin burying cables, then be sure to bury the controlling communications network alongside. If we add more intelligence and more devices to the grid, we need to ensure the communications have the bandwidth to transport that intelligence quickly and reliably, to and from where it's needed from the core to the farthest edges of the grid. And if we add more energy sources, they also need communications connectivity to monitor and control their energy flow so that they don't destabilize the grid and compound the problem.

With the predictions around cyber security, communications is obviously at the heart of the issue; if not addressed as it gets deployed, communications equipment provides the way in for cyber attackers. I firmly believe in my grandmother's old adage that prevention is better than having to find a cure. Therefore, any steps we can take to improve the security of the communications network by designing it in from the start so that it cannot be breached makes for a sound strategy.

There are many possible angles on the theme of operational efficiency. The IDC predictions talk about Chief Information Officers getting to grips with operations-enhancing IT investments, and further deployment of Distribution Automation and monitoring devices to improve grid operations. Once again, communications is a necessity in these areas. Jesse Berst, Chairman of the Smart Cities Council, is recently quoted as saying, "We are heading toward the day when utilities won't have to have the four or six or 10 separate networks they maintain now, but only one." For the sake of transparency, I need to mention that he said this in a review[6] of one of Alcatel-Lucent's products. But still; it's another respected industry heavyweight pointing to communications as a means to achieve significant operational efficiencies.

Future-proof foundations

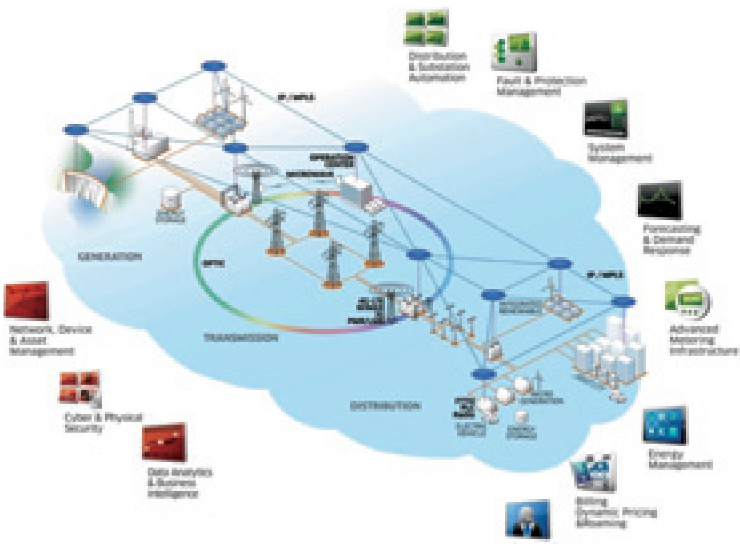
With that in mind, I'd like to share a few thoughts on what utilities can and perhaps should be doing with their communications networks in 2013.

The first consideration is that whatever is done needs to be future proof. We are in a situation today where many utilities are managing multiple networks due partly to institutional momentum, and partly because of a lack of ability to predict and/or justify to the regulators what potential needs may arise in the future. So the communications network must provide the foundation that can absorb new applications for increased operational efficiency, flexibility, and productivity as and when they are invented. Second, the solution must be highly reliable: the ideal solution is one that offers at least the same level of reliability, QoS (Quality of Service), and even better security than the communications networks currently in operation while supporting the full array of existing TDM and new IP/Ethernet services that are needed for core operations and smart grid deployments. Third, the network must get close to customers – both electricity consumers and producers – to empower consumption and production choices. Finally, all this must be achievable in a reasonably rapid and certainly cost-effective manner, keeping CAPEX and OPEX to a minimum.

It is generally acknowledged that IP (Internet Protocol)-based networks are the way to go. Why? Because IP is the dominant standard for communications networks globally. It is the backbone of the Internet, and as such, there are many parties with a vested interest in IP remaining the future-proof foundation of all communications quite possibly forever. Or at least until we have telepathy. But IP represents quite a shift for utilities and transmission operators who have been maintaining traditional time division multiplexing (TDM) over Synchronous Digital Hierarchy (SDH) or Synchronous Optical Network (SONET) networks. And whereas in the past distribution operators have only needed minimal communications coverage in most of their medium and low voltage service territories, they now face the challenge of extending and deploying new communications infrastructures outside the core and towards the remotest edges of the grid to support distribution automation, renewables and micro-generation sources that could destabilize the electrical load if not carefully monitored and controlled.

IP technology serves as the bridge between applications and the underlying communications medium. This is providing utilities with the capability today to deploy new IP-based Smart Grid applications, such as:

- IP-based supervisory control and data acquisition (SCADA);
- IEC 61850-based substation systems;
- Synchrophasor systems;
- Video surveillance systems;
- Distribution automation;
- Advanced metering infrastructure;
- Other applications that include voice over IP (VoIP), IP mobile radio, Wi-Fi® mobility, physical substation security, corporate local area network (LAN) access, and more.



IP/MPLS can be used throughout a Smart Grid communications network, supporting today's TDM applications and future IP-based technology

Putting IP to work for utilities

So while IP clearly can be considered as a future-proof possibility, does it meet the other compulsory criteria: Is it secure? Will it be reliable? Can I manage it? Can it support the applications I use today?

Well, the honest answer is no, not on its own. But there is a proven way it can be made to. To support mission-critical traffic, a technology called MPLS (Multi-Protocol Label Switching) must be added to the IP-based communications network. MPLS is commonly used by telecom service providers to add the deterministic performance advantages of a circuit-based network to an IP network and enable network convergence, virtualization and resiliency. In other words, with MPLS, IP becomes just as fast, predictable, and reliable for delivering all traffic as the current utility networks. Even that most critical of applications – teleprotection – has been proven to work over IP/MPLS[7] with the same or better performance as on TDM networks. It does this by separating (virtually) the different types of traffic or applications. The traffic flows can also be prioritized so, for example, teleprotection and SCADA will always get priority over CCTV or intranet traffic. That's right, I said intranet traffic: IP/MPLS connectivity out into your sub-stations and other remote locations can even provide the single connection for engineers into your corporate network.

But with that extension of connectivity into lower value and less-secured assets, like sub-stations, there is an increased risk of cyber attacks. I read a news article[8] in the New York Times a while back talking about a paper by a Chinese graduate student that discusses how easy it is to compromise the smart grid by breaking into low-value, less protected assets and causing a cascading failure across the grid. This is, of course, denied as being possible by some but regardless, with the right products, IP/MPLS can bring a variety of answers to the cyber security table:

- Mechanisms to protect the management, control and data planes through access control lists, filters and authentication of signaling messages, assist in the prevention of session hijacking, spoofing, denial of service attacks and other such malicious network behavior.
- Strong password security is provided by SNMPv3 confidentiality and integrity features and Secure Shell (SSH) encryption.

Security with an IP/MPLS network is further enhanced when integrated with:

- Stateful firewall to stop unexpected and unwanted traffic from entering the network.
- Network address translation (NAT) to protect and hide private addressing space from external entities.
- Group encryption to protect sensitive data during transit and ensure data integrity and privacy.
- Intrusion detection system (IDS) and intrusion protection system (IPS) to detect and protect against network and traffic anomalies.

Smooth evolution

So the technology to improve reliability, security and operations exists. IP/MPLS. But how do you get to it?

Well, a flexible, evolutionary transformation is desired in order to preserve existing investments and to minimize risks. As I've explained, IP/MPLS can support TDM and legacy applications and one approach amongst Alcatel-Lucent customers has been to deploy an IP/MPLS network then transfer applications in batches or one at a time, decommissioning old legacy networks as they go.

That means there's never any risk to reliability, and the transition can be managed as business models, technical expertise, or budgets dictate. The end result is that all your applications and services are concurrently supported by the same IP/MPLS network, so the overall number and costs of telecom equipment required and maintained are drastically reduced. You then have a future-proof network just aching to take on the traffic generated by an explosion of smart devices and new IP applications.

Another advantage of using IP/MPLS from the core all the way to the field area network is that it can be used on many transport technologies. Core networks commonly use fiber optic cabling, but that's not generally economically viable in remote locations. IP/MPLS can be combined with microwave transport in areas that lack fiber, or with wavelength division multiplexing (WDM) transport when a very large capacity is required. Frequently IP/MPLS is combined with high-speed Ethernet transport from 1 Gigabit (Gb) to 10 Gb and 100 Gb. It has even been deployed over WiMAX and other 'point-to-multipoint' radio technologies. That's quite a few supported technologies. The bottom line is that IP/MPLS is flexible enough to work across different physical and technological media, depending on the needs of the grid.

By the way, a single, converged, end-to-end IP/MPLS network only needs a single service management platform, making it far faster and more efficient to introduce, operate and troubleshoot any and all devices and services. With IP/MPLS, deploying new services has now become child's play; using the service management software, click on the end points and select a service such as SCADA from the menu and it is automatically and remotely provisioned with the correct QoS and security parameters for the application.

Betting on IP/MPLS

So do you still want to hear my crazy prediction for 2013? Well it's this: I believe that 2013 will be the year that IP/MPLS goes mainstream for utilities, from the core to the very edge of the grid. One by one the concerns have been allayed, the benefits have been proven, and the numbers have been shown to make sense. And whether or not you want to call it part of a Smart Grid strategy, I think fundamentally it just makes for a smart business strategy.

[1] Source: IDC Energy Insights Predictions 2013: North American Utilities

[2] Source: Zpryme Research & Consulting, Smart Grid Index: December 2012

[3] Source: Electric Energy T&D Magazine, November-December 2012, Guest Editorial: Securing Utilities from Cyberattacks "For the times they are a-changin"

[4] Source: Zpryme Reserach & Consulting, 2012 Utility Cybersecurity Survey

[5] Source: New York Times, December 18 2012, "How N.Y.U. Stayed (Partly) Warm and Lighted"

[6] Source: Smart Grid News, December 7 2012, "New Alcatel-Lucent grid product part of a larger grid communications trend"

[7] Source: Iometrix Test Report, August 26 2011, "Teleprotection over IP/MPLS Networks

[8] Source: New York Times, March 20 2010, "Academic Paper in China Sets Off Alarms in U.S."

The benefits of IP include simple ways to deploy and configure new services and devices, such as Alcatel-Lucent Service Portal Express for Utilities

ABOUT THE AUTHOR

Mark Madden is the Regional Vice President for Utility Markets in Alcatel-Lucent's Americas Region. In 2012, Mark was elected to the board of the Utilities Telecoms Council (UTC) Smart Networks Council. With Alcatel-Lucent, Mark is responsible for utility market strategy, strategic partnerships, and business development in North and South America. Mark joined Alcatel-Lucent in 1996 and has over 30 years experience with leading companies in the Information and Communications Technologies industry. Contact Mark at *mark.madden@alcatel-lucent.com*.

Guest Editorial 2

Outlook for the Energy Efficiency Industry

By Albert Thumann, PE, CEM

Since 1977, when the Association of Energy Engineers (AEE) was founded, energy efficiency has been a growth market regardless of which party occupies the White House. Demand for energy efficiency professionals also continues to grow. Over the last five years, even as the US economy was in turmoil, the AEE's membership has doubled to 16,000.

In 2012, the association conducted a survey of our members for additional insights into demand for energy efficiency, professional education and training programs, and trends in the industry. The survey found the following:

a) Growing shortage of energy engineering professionals

Sixty-seven percent of survey respondents predicted a shortage of qualified professionals in the energy efficiency and renewable energy fields in the next five years. Contributing to this is the fact that nearly a third (32 percent) of those surveyed say they plan to retire in the next 10 years.

AEE works with numerous colleges and universities to encourage students to enter the energy engineering profession, and our foundation provides a scholarship program for energy engineering students. However, despite the growth in demand for energy efficiency professionals, there are few degree programs related specifically to energy engineering and management, which may contribute further to a shortage of qualified energy engineers in the years ahead. A recent survey by AEE indicated that education for a degree in energy engineering was offered by the following colleges and universities:

- Arizona State University – solar energy engineering and commercialization graduate program
- Boston University – energy technologies
- Lehigh University (Pennsylvania) – environmental/energy engineering
- Indiana University-Purdue University Indianapolis – energy engineering
- Oregon State University – energy systems engineering
- Oregon Tech – renewable energy engineering, Master of Science in renewable energy engineering
- Penn State – energy engineering
- Princeton University (New Jersey) – sustainable energy
- University of California, Berkeley – energy engineering
- University of Illinois at Chicago – energy engineering; Master of Energy Engineering
- University of Michigan – energy systems engineering; Master of Engineering in energy systems engineering
- University of North Texas – mechanical and energy engineering

b) Growth in the clean energy marketplace

Clean energy from energy efficient technologies, renewable and alternative energy sources will continue to increase. The Center for American Progress predicts that by 2020 clean energy will be one of the world's biggest industries, worth as much as US$2.3 trillion. Business researchers Frost & Sullivan project the revenue from energy management services in North America alone will grow to more US$40 billion in 2013. There are several factors that contribute to this growth.

The market for energy efficiency continues to be driven largely by businesses' desire to increase profits by reducing costs – and energy is a major component of most businesses' overhead costs. In fact, 69 percent of those surveyed by AEE indicated that electric rates have increased since last year, while even more (88 percent) said their company has a sustainable development policy and energy efficiency is a component.

However, as energy costs increase, the cost of renewable energy continues to become more economical, leading more businesses to adopt renewable energy technologies. The AEE survey found that 73 percent of respondents plan to install photovoltaic (PV) systems at their facility in the next three years, while 30 percent plan to install geothermal in the same time period.

Another factor impacting the adoption of clean energy technologies is changing energy policies. For example, both Germany and Japan are working to phase out nuclear power. While some of this capacity will likely be replaced with newly abundant natural gas, renewable energy and energy efficiency will be increasingly important to meeting demand in these nations, and in nations around the world.

Conclusion

The clean energy industry is poised for continued growth and has the potential to outperform other sectors. The cost of energy efficient technologies, even without tax deductions, credits and utility rebates, continues to become more affordable and economically viable.

In addition, with retirements among current energy engineering professionals and a steady increase in demand for energy efficiency, the sector may also anticipate tremendous growth both in employment and in demand for quality education and training programs.

ABOUT THE AUTHOR

Albert Thumann founded the Association of Energy Engineers in 1977 and has served as its executive director ever since. He has personally trained more than 8,000 professionals on the efficient use of energy and has lectured around the world on energy topics. Thumann is a licensed professional engineer in three states and Certified Energy Manager (CEM). He received a Bachelor of Science in Electrical Engineering (BSEE) from City University of New York, and a Master of Science in Electrical Engineering (MSEE) and a Master of Science in Industrial Engineering (MSIE) from New York University.

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