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Market Transformation Past and Future

Electric Energy T&D MAGAZINE

Publisher:
Steven Desrochers:
steven@electricenergyonline.com

Editor in Chief:
Terry Wildman:
terry@electricenergyonline.com

Account Executives:
Eva Nemeth: eva@electricenergyonline.com
Murrae Gomola: murrae@electricenergyonline.com

Art Designer:
Anick Langlois: alanglois@jaguar-media.com

Internet Programmers:
Johanne Labonte: jlabonte@jaguar-media.com
Sebastien Knap: sknap@jaguar-media.com
Tarah McCormick: tarah@jaguar-media.com

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834 Montée Masson
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E-mail: jaguar@jaguar-media.com
Web: www.electricenergyonline.com

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Cover photo of Peter Weigand, Chairman and CEO, Skipping Stone, LLC

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POWERPOINTS

We're Only Human

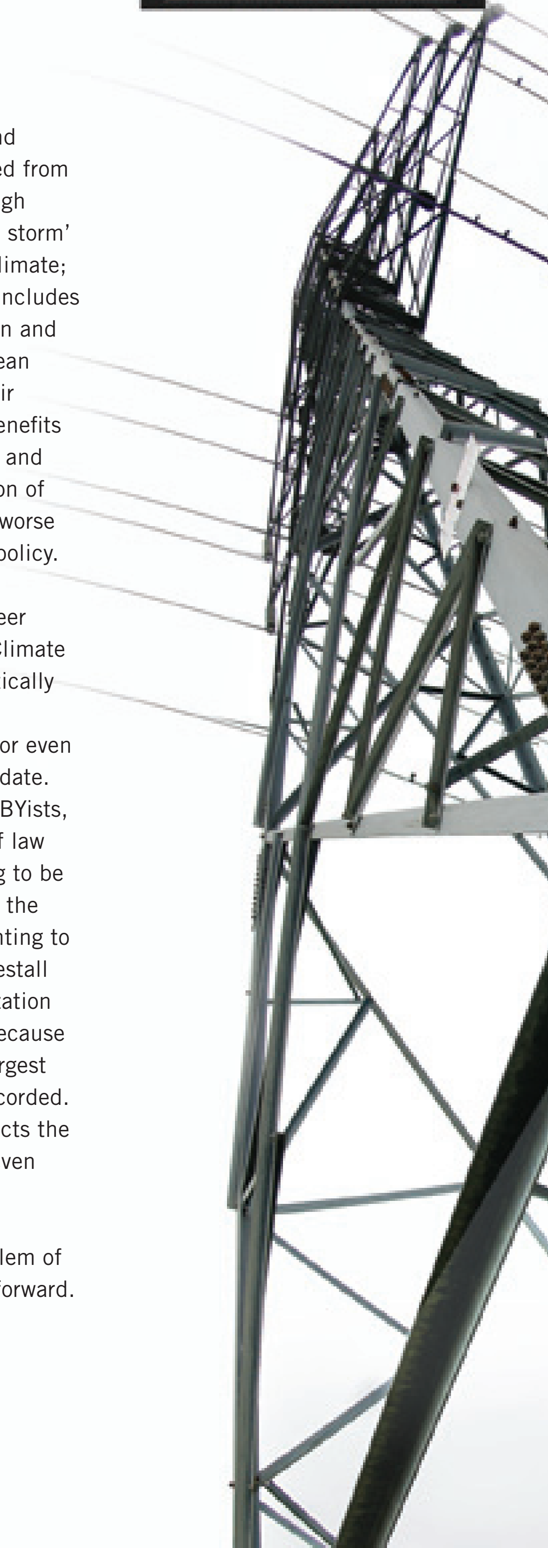
History shows the first evidence linking climate change to human activities was carefully documented in 1897 by Swedish physical chemist Svante Arrhenius (1859-1927). What began as more of an exercise about the effect of rising CO_2 on ambient temperature soon generated a flood of increasingly urgent and conscientious warnings about the rapid warming of Earth and the dire consequences of inaction. Even then, in spite of growing scientific and anecdotal evidence of destabilization of climate the dialogue on the phenomenon foundered under pressure from disbelievers and naysayers. It's long been known that CO_2 naturally occurs in the atmosphere, oceans, soil, plants, and animals. The trouble comes from human activity that alters the carbon cycle, both by adding more CO_2 to the atmosphere and by influencing the ability of natural sinks such as our oceans and forests to remove the gas from the atmosphere.

"We have entered a 'long emergency' in which a myriad of worsening ecological, social, and economic problems and dilemmas at different geographic and temporal scales are converging as a crisis of crises," says David W. Orr, the Paul Sears Distinguished Professor of Environmental Studies and Politics at Oberlin College in Ohio. "It is a collision of two non-linear systems – the biosphere and biogeochemical cycles on one side and human institutions, organizations, and governments on the other."[1] Unfortunately those on both the sides of the issue become unbalanced, unrealistic, and ideological and do not solve the fundamental problem of needing to manage carbon pollution.

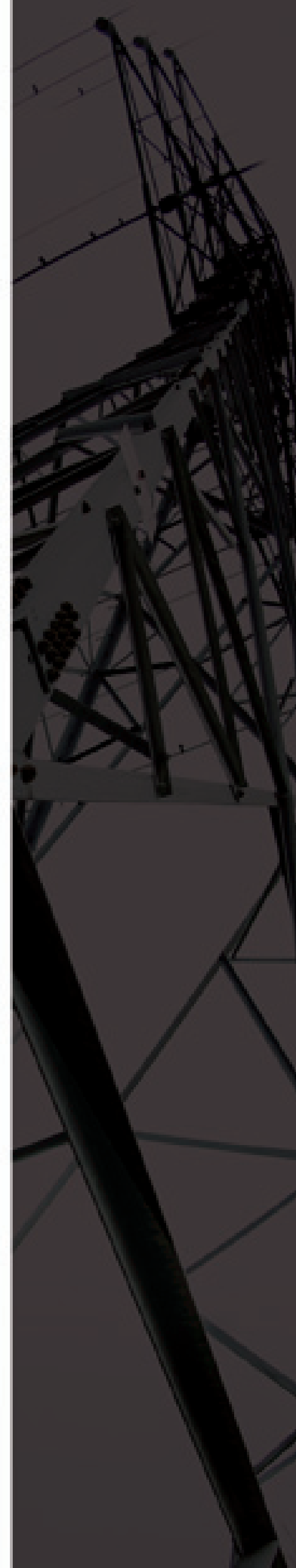
Sadly, the response at the national and international levels has thus far ranged from total indifference to being weak through inconsistency. We now face a 'perfect storm' caused by the collision of changing climate; spreading ecological disorder, which includes deforestation, soil loss, water pollution and shortages, species extinction, and ocean acidification; population growth; unfair distribution of the costs, risks, and benefits of economic growth; national, ethnic, and religious tensions, and the proliferation of nuclear arsenals. These are all made worse by systemic failures of foresight and policy.

Part of the problem we face is the sheer enormity and difficulty of the issue. Climate change is scientifically complex, politically divisive, economically costly, morally contentious, and all too easy to deny or even defer to others to deal with at a later date. Again cynics, non-believers, and NIMBYists, most of who are stirred up by plaintiff law firms looking for business, are proving to be the worst offenders. By not accepting the overwhelming scientific evidence pointing to the urgent need to anticipate and forestall the worst effects of climate destabilization we might as well roll up the streets because we will be guilty of committing the largest political and moral failure thus far recorded. Oddly this 'crime,' which totally impacts the future of life on this planet, doesn't even have a name.

This is all part and parcel of the problem of how we must govern ourselves going forward.



POWER POINTS



Forty years ago in his essay *An Inquiry into the Human Prospect* economist Robert Heilbroner stated, "I not only predict but I prescribe a centralization of power as the only means by which our threatened and dangerous civilization will make way for our successor."[2] He included global warming along with other threats to industrial civilization in his paper. Heilbroner also noted that, in the final analysis we might very well be found guilty of simply not caring enough to do what was right for posterity. He stated that the extent to which power must be centralized depends on the capacity of countries that are accustomed to affluence to exercise the self-discipline necessary to step up to the plate.

History again shows that the performance of highly centralized governments is far from encouraging. They are effective at waging war and partially solving economic problems but they continually fail to get out of the way of their own usually massive size, sluggishness, and multi-level bureaucracy.

It's not that it can't be done. I have never heard anyone grumble over the costs of water treatment. People know better. They know that if they don't do the right thing for their company and society, if they dumped foul wastes into public waterways, it would only come back and bite them on the backside. People know the resource is finite and we couldn't survive without clean water. Companies for the past three decades have been showing responsibility and few, if any, grouse about the price. This is evident in countless firms as costs of investments are capitalized, preventive maintenance is built into the operating plan, and staff members are properly trained to do their jobs. Water treatment is part of operations, no ifs, ands, or buts.

So why on earth are we debating climate change instead of managing gaseous waste the way we manage physical and liquid waste? I suspect the answer is as simple as the fact that, for the most part, we can't see or taste CO_2. It often simply blows away, leaving us with the age-old answer to many problems – out of sight out of mind. Is it that we can't know what we can't see? We can't understand what we can't taste? Wrong! We are a heckuva lot smarter than that.

"I believe we're mired in a dysfunctional debate on climate change because it's a classic way for politicians to exhibit their self-professed profundity," said John Hofmeister, former president of Shell Oil. "What I object to are self-declared experts who, lacking any scientific knowledge or credentials, basically repeat what they have read, have no certainty other than their opinion, and believe themselves omniscient on the subject. They can present themselves as the saviors of humankind, the protectors of the biosphere, the heroes of modernity, the avowed enemies of the unclean."[3]

We have already proved that we are well on the way to managing physical waste and liquid waste with tangible social and economic benefits. Why then can't we turn a social and environmental problem like carbon emission into value-creating enterprises that improve society as well as the sustainability of our earth? In actual fact we can set aside our arguing for or against global warming or climate change because that's not the point. We can also forget the extortion by developing countries for climate change remediation payments. The issue is whether we have the wherewithal, wisdom, will, and foresight to preserve and improve the human enterprise in the midst of a growing human crisis. Let's help all of those who need it with the technology of gaseous waste management at the same time we're working on it ourselves. With a population of 10 billion people by 2100, we will have no choice but to come to terms with the prickly issues of politics, political theory, and governance with wisdom, guts, and creativity.

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1 Orr, D. *Governance in the Long Emergency*. Is Sustainability Still Possible? Washington: Island Press, 2012
2 Ibid.
3 Hofmeister, John. *Why We Hate the Oil Companies: Straight Talk from an Energy Insider*. New York: Palgrave Macmillan, 2010

Systems With Intelligence is Expanding

December 2016

Systems With Intelligence, a Canadian provider of substation monitoring equipment, has announced the opening of its new office in Mississauga, Ontario. The new location is headquarters for R&D, manufacturing, sales and support.

Angelo Rizzo, the president and CEO of the company said, “Our business has been steadily growing over the last few years and we needed more space, the new office allows us to grow the team and expand our R&D and production capability.”

Systems With Intelligence designs real time visualization products using advanced thermal and visual imaging cameras that continuously sense and analyze the conditions of operating assets. Thermal analysis finds hot spots and detects problems in equipment before failures occur. The new location has state of the art research and development labs and production facilities to meet the growing demand from electric utilities. “Utilities are under constant pressure to provide higher levels of service without increasing rates. Our substation hardened systems allow utilities to find and fix problems before outages occur, saving them and their customers money,” said Rizzo.

Founded in 2009, Systems With Intelligence has been providing security and monitoring solutions to customers with applications in electric power substations, renewable energy and oil and gas markets. For additional information, please contact Systems With Intelligence Ltd.

Company Website: *www.SystemsWithIntelligence.com*

Energy Department Releases First-Ever State of the National Labs Report

January 2017

U.S. Secretary of Energy Ernest Moniz announced the release of the inaugural State of the Department of Energy National Laboratories Report.

The report highlights the remarkable accomplishments and capabilities of the National Labs, evaluates some of the improvements DOE has made in recent years in its management and coordination with the labs, and charts a course for continued American leadership in science and technology. Overall, the report concludes that the vitality of the DOE National Laboratories has improved over the past decade in part due to increased investments made into the labs and from a focus on enhancing the relationship between the Laboratories and DOE.

“Our National Lab system is an enduring science and technology powerhouse comprised of more than 20,000 scientists and engineers who deliver new discoveries and provide world-class technological capabilities,” said Secretary Ernest Moniz. “This report makes clear that the state of our National Lab system is strong, and that it has become stronger in recent years. This report also provides a roadmap to continue supporting American leadership in science and technology in our labs and beyond.”

Some of the specific lab accomplishments highlighted in the report include:

- Conducting fundamental and applied research that enabled both the shale gas revolution and the development of nuclear energy, photovoltaics, and energy storage for the transportation industry;
- Developing energy efficiency technologies and standards that have saved U.S. taxpayers over $1 trillion;
- Delivering forefront scientific discoveries, from new chemical elements to new states of matter;
- Sustaining safe and secure U.S. nuclear weapons stockpile in the absence of nuclear testing through high performance computing, cutting-edge innovations in facilities, and other advanced technologies.

The report organizes issues and recommendations into six themes: Recognizing Value, Rebuilding Trust, Maintaining Alignment and Quality, Maximizing Impact, Managing Effectiveness and Efficiency, and Ensuring Lasting Change.

As the report notes, significant progress has been made in many of these areas over the last few years - from prioritizing mission-driven DOE-Laboratory relationships rather than mere transactional relationships, to improving infrastructure planning and pursuing simplified contracting models. Secretary Moniz’s reorganization of the Department and the creation of a single Under Secretary for Science and Energy has maximized impact by establishing a series of crosscutting initiatives that have brought together experts from across the DOE-Lab complex to tackle major challenges like grid modernization.

The report also identifies challenges that lie ahead, such as maintaining a skilled workforce and sustaining the unique, complicated, fragile, and often aging infrastructure that supports the suite of critical facilities and assets.

The report also contains summaries highlighting the capabilities and accomplishments of each of the 17 National Labs, and details the DOE Laboratory management model and recounts the history of the Lab system. The report was prepared in response to the Congressionally-mandated Commission to Review the Effectiveness of the National Energy Laboratories, which recommended that the Department should better communicate the value that the labs provide to the Nation.

The entire report can be found here https:*//energy.gov/downloads/annual-report-state-doe-national-laboratories*

INDUSTRY NEWS

NYPA Launches Groundbreaking Monitoring and Diagnostic Center

Center Using G.E. Software Will Give Nation's Largest State-Owned Utility Ability to Monitor All of Its Assets Simultaneously

January 2017

The New York Power Authority announced that a comprehensive central command center is now online that analyzes the performance of its expansive generation and transmission network and identifies potential problems before they can cause service outages.

The center, using software provided by GE Power, will help NYPA achieve its 2020 Strategic Plan to improve the efficiency and reliability of its facilities while also making them more cost-effective.

The Integrated Smart Operations Center will initially monitor operations at NYPA's 500-megawatt combined-cycle power plant in Queens and expand to monitor all NYPA assets.The center will be used to predict potential failures and unplanned downtime to increase reliability and lower operational costs and risks.

The center also supports the goals of Governor Andrew M. Cuomo's Reforming the Energy Vision strategy to create an energy system in New York that is cleaner, more efficient and resilient. It will also help achieve the Governor's Clean Energy Standard, which requires that half of all electricity used in New York come from renewable sources by 2030.

"This is an exciting milestone in our digital journey," said Gil C. Quiniones, NYPA president and CEO. "The Integrated Smart Operations Center will become the new standard in utility asset management and help us fulfill our core mission to provide power to our customers that is both low in cost and reliable."

NYPA, the nation's largest state-owned utility, typically supplies 15 to 20 percent of the state's power daily from its 16 generating facilities and owns one-third of New York's high-voltage power lines.

The center will use asset performance management software that runs on GE's Predix operating system. Using sensors embedded in equipment such as turbines and transmission lines, it will better enable NYPA to better detect problems that could affect the utility's ecosystem, sometimes weeks in advance.

"With this deployment, NYPA is pioneering change in the digital transformation of the electricity industry," said Ganesh Bell, chief digital officer of GE Power. "GE's Asset Performance Management (APM) application on the Predix platform will unlock the value of existing data to impact machine health and reliability, setting NYPA up for success and ensuring its goals related to efficiency and customer demand can be met."

In time, NYPA intends to use the center to also monitor its cybersecurity, physical security, network operations and information technology and operations technology services throughout its generation and transmission system, which stretches from Massena, next to the Canadian border, to eastern Long Island.

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

Market Transformation Past and Future

We are in discussion with Skipping Stone's leadership team, celebrating its 20th year in business. CEO Peter Weigand, President Greg Lander and Partners Ross Malme and John Brown highlight major market changes that have transformed markets and where they envision future transformative market shifts.

EET&D: What prompted you to launch Skipping Stone 20 years ago?

Weigand: I was a senior executive at a major energy company tasked with transforming the company through a combination of mergers and acquisitions and overhauling the organization from top to bottom. Through that process, I used a variety of consultants and wasn't happy with the results for the money I was spending. Being an entrepreneur at heart, I decided there had to be a better model based on providing consulting services that used industry veterans only and on measuring projects based on client success. That model proved to be unique at the time and is still our model today.

EET&D: Over your twenty-year history what have been the biggest changes that have transformed energy markets in your view?

Weigand: When you put a number of industry veterans together, the fun part of what we do is to collaborate on market changes and develop innovative ideas and solutions for the benefit of a wide variety of clients. While I could list many areas of change, I think the most profound changes can be categorized into four (4) areas: 1 - wholesale markets, 2 - end user empowerment, 3 - renewables, and 4 - advances in technology.

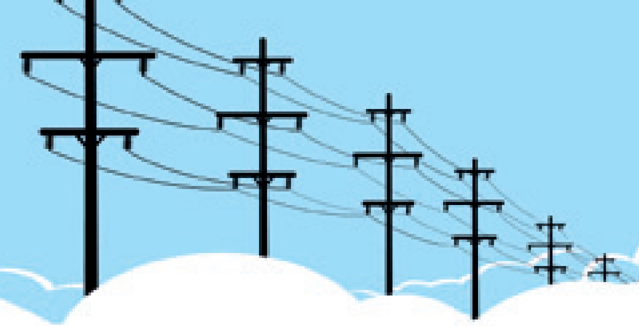
EET&D: Let's take these one at a time. Regarding wholesale markets, how has that impacted the marketplace?

Lander: There are two separate wholesale markets, natural gas and power. Each emerged during different decades and, based largely on their distinctly different business models, have taken their own paths.

On the gas side, it is entirely a bi-lateral market with contracts between two parties for everything from supply, to movement of gas, to consumption. When the wholesale gas market transformed from a pipeline-as-merchant market to its current restructured pipeline-as-transportation form, it meant that going forward all changes in pipeline configuration and services were to be effectuated only if and when there were willing parties agreeing to contract for specific services to support the change. In addition, it was determined there needed to be a workable secondary market in pipeline capacity. These two changes, and the essential bi-lateral nature of all these market structures, has drastically altered how the gas markets work. Where the wholesale gas market was simple pre-restructuring, it is now much more complex. This has driven trading, futures markets, and capacity release markets and has enabled more gas fired generation on the power side.

Turning to the wholesale electric side, with the introduction of Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) that operate alongside legacy, vertically integrated electric utilities, the wholesale electric market retains its centrally operated model. This model differs from the wholesale gas model in one significant way: all system configuration changes and new services are centrally administered with costs of changes socialized across the participants and service changes propagated by rules applicable to all largely without regard to any pre-existing bilateral arrangements.

This difference in business models has been most pronounced as these two markets become ever more interdependent, and coordination issues between them have come ever more in focus to policy makers and market participants alike.



Brown: As Greg said, the wholesale power markets were forever changed with the introduction of independent system operators, who now run a variety of markets such as generating capacity markets, transmission rights markets, and ancillary markets, plus real time energy market clearing, etc. This created an explosion of trading opportunities and changed how power plants are run based on economics not just reliability. In a sense, costs associated with reliability are now priced/recovered less through rate bases and more through wholesale market dynamics.

Malme: Over the past twenty years we have experienced an explosion in the number of companies and people now participating in the market. This could not have happened without deregulation at the wholesale level by FERC.

Weigand: For utilities, the changes in the wholesale gas and power markets have added multiple layers of complexity compared to twenty years ago. While still carrying the mandate for reliability, there are now a thousand ways to slice and dice how to accomplish that, yet to a large degree at the distribution level utilities and regulators are still tied to using old style ratemaking models. We see a major disconnect between the newer wholesale market models and traditional ratemaking that puts previously unrecognized risks on utilities. This is a very serious problem currently, and crying for new and viable solutions.

EET&D: What do you foresee in wholesale markets that will drive more changes?

Lander: An area we have been deeply involved with over the past couple of years is the synchronization and coordination between the wholesale gas and power markets. Now that the power market is driven more by gas than coal, plus the emergence of significant levels of renewables, the gas market needs to change to adapt. We foresee the gas wholesale market evolving from its current daily transaction methodology into one that transacts both daily and, increasingly, along the lines of an hourly or at least sub-day transaction model.

Weigand: We are seeing more and more international markets adopt American style wholesale market models. Currently we are involved in the Japan market, where they will be implementing both a wholesale gas market and an ISO-style power market over the next few years. At the same time, Japan is taking retail deregulation much further than the U.S. has by allowing every customer nationwide to choose their commodity supplier for both electricity and gas.

Malme: The use of demand response continues to change from a pure capacity play to where we envision it playing a larger role in the ancillary markets. This has just started to happen and as technology advances, so too will demand response as a more robust wholesale market tool.

EET&D: What do you mean when you say end user empowerment?

Weigand: Twenty years ago, customers purchased power on utility tariffs and maybe utilized demand side management incentives. Today, in many markets, customers can choose their electricity supplier, participate in demand response programs, install solar or other on-site generation and large companies have proactive sustainability programs. Add to that smart meter data, smart thermostats, LEED for buildings, smart cities, etc. In short, more and more customers are engaged in the energy markets directly or through retailers, solutions companies, utilities and technology providers.

EET&D: How has the demand side of the grid evolved over the last several years?

Malme: The old legacy-regulated demand side management programs, which the regulated utility used to manage through programs like industrial customer interruptible tariff programs and residential direct load control programs, are being replaced with new programs. Some programs allow the customer, perhaps through their aggregator or retailer, to bid into wholesale markets and yet others pay customers for shedding load during peaks.

Advances in technologies such as Advanced Metering Infrastructure (AMI) and near real time demand response management software (DRMS) have dramatically increased the value and reliability of demand response, not only to wholesale markets, but also to transmission operators, energy traders, distribution companies, CSPs, retail electricity providers, and the retail customers themselves.

EET&D: Where do you see the demand side evolving to in the future?

Malme: Going forward DR is evolving into one of several market products and services and will be combined with or operate along-side distributed energy resources (DER) including rooftop solar PV, and behind-the-meter energy storage. It will now begin to complement and, yes, these individual offerings will even compete against one another at the edge of the grid. With the onset of smarter and smarter buildings and cities, we think the demand side, or end users, will drive more innovation and opportunities than the generation side over the next 10 years. This is especially true if what Peter highlighted earlier regarding old style ratemaking limits the ability for utilities to invest and participate in demand side market opportunities.

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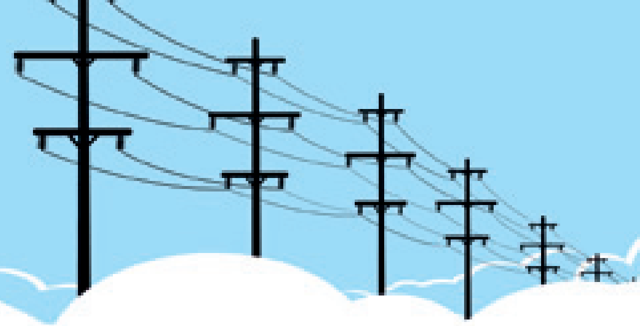

Weigand: We are seeing utilities create nonregulated business units to capture demand side opportunities as well as to expand outside their footprint. We expect that trend to grow much larger over the next 5 to 10 years. The reality is that if the traditional utility model and rate structures aren't addressed, it doesn't bode well for regulated utilities, and that isn't healthy for anyone.

EET&D: Where do you envision retail choice going over the next few years?

Brown: For the past couple of years, retail choice markets have crested the maturity curve. The number of retailers has shrunk due to consolidation, and new entrants are much fewer in number. In addition, some states, notably New York, are really tightening the market rules, which will likely result in many retailers exiting those markets.

Weigand: Of course, I'm a free markets believer. Utilities without retail choice have fought against it successfully for years, which is why no new markets have opened in the last decade or longer. At the same time, those same utilities, by and large, pass through the costs of the commodity to consumers without making a margin. One wonders why do this if you can't make any money at it? Perhaps the new model is for utilities to view themselves as a reliability and services company instead of an electricity commodity provider.

EET&D: Obviously, renewables twenty years ago weren't significant, why are they today?

Lander: Several key factors, the most important being government intervention with tax incentives and state-level renewable portfolio mandates. Neither of these would have happened, however, without political support from voters; therefore, the public believes green and climate change need to be addressed. Renewables is an easier way to 'support' this than perhaps using less energy.

Weigand: Over the past couple of years there has been a shift in renewable drivers. For consumers, it became easy to finance solar with no money down, long term contracts. For the Fortune 500, the driver is achieving sustainability goals via renewables because energy efficiency can only go so far. We are now seeing utility scale projects funded on the backs of corporate customers at a faster pace than traditional utility PPA's.

Brown: An important growth aspect of the renewable market has been participation by the finance community. Not just project finance, but trading and derivative participation with newer concepts like synthetic PPA's, contract for difference swaps, and others that serve to justify and finance renewables.

EET&D: You mentioned advances in technology as an area of significant change, can you elaborate on this?

Brown: Technology has transformed the way we buy and sell energy, manage the gas and electric grids, interact with suppliers and customers, and more. It has given us unprecedented access to data and information, literally touching every aspect of the energy value chain. Looking at the way market participants buy and sell electricity, we have seen major changes in the systems companies use to manage their portfolios and the associated risks and we've seen changes in how transactions are managed. On much like hourly trading in electricity led to technology changes on the electric side, on the gas side, there will be a new round of technology changes as pricing of gas and transportation services adds hourly and sub-day transacting to its compliment of service offerings.

In the late 1990s, I was at the Continental Power Exchange. We launched an online system for trading next-hour electricity - CPEX. These were physical trades that cleared through the system. CPEX ran on a dedicated private network as most people thought the Internet didn't offer adequate security. CPEX ultimately evolved into the Intercontinental Exchange (ICE), now the most used system for trading wholesale electricity. ICE runs over the Internet and offers physical and financial products for a host of commodities. Over this same time period we have also seen the evolution from spreadsheets to dedicated commodity trading and risk management systems that provide straight-through processing from deal entry to invoicing and risk management.

This has enabled unprecedented access to trading partners and products, as well as accelerated market expansion. Similar advances have occurred in the way people schedule and manage transmission with e-Tagging solutions and the Open Access Same-Time Information System (OASIS) network.

In our view, the gas side will see a similar evolution in transactions, risk management and tracking systems as hourly and sub-day pricing and transacting proliferates to support gas-fired generation, which is becoming ever more variable due both to the behind the meter changes stemming from DR/DERs and to the ever-increasing penetration of variable output renewable electricity generation at the wholesale level.

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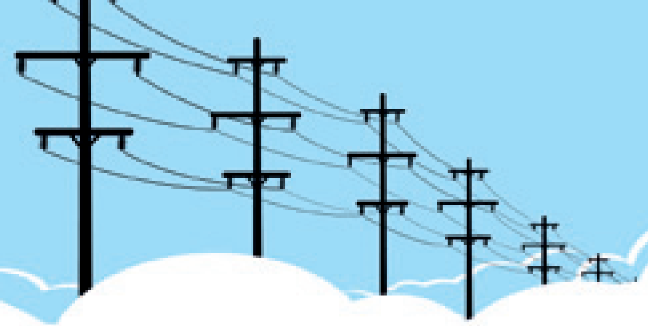


Malme: From the grid perspective, the past twenty years has seen the explosion of information and automation with everything from smart meters to AMI to substation automation – and many other areas. The current challenge is how to make all this big data pay off in terms of cost reductions, customer participation, profitability, etc.

Weigand: Twenty years ago you could probably count the number of technology vendors serving the energy marketplace. Today it's nearly impossible to count all the technology companies who have some sort of solution, whether software, hardware or information related. As the twenty-first century dawned we saw many billions invested in energy technology by venture capital, with investors still pouring money into energy tech. Over the past ten years we have seen private equity pour billions in through acquisitions and roll ups. Going forward we see the money crowd getting even more involved, including expanding their horizons to international markets.

Malme: Speaking of international technology opportunities, for the past several years we have been hosting trade missions from emerging country utility and energy ministries who are coming to America to learn how our energy markets work and to buy U.S. technologies to adopt for their own smart grid initiatives. America is leveraging, through significant exports, our global leadership position in energy technologies.

EET&D: So how do you make sense out of all this?

Lander: Because we work across several sectors, such as utilities, gas and power retail and wholesale, renewables, demand response and distributed energy, we get to see a wide variety of technologies. Add to that mix our perspective gained from many years in the energy business, we are able to provide our technology clients with strategies and implementation plans based on what the market actually needs today and what the changes we see coming will mean it will need tomorrow.

Weigand: For clients who are in need of technology, we always view technology solutions from our foundational core of measuring our success based on client success. As a result, we sit on the client side and if the solutions explored don't make business sense, then we, and they, won't be successful. Using this basic methodology keeps our consulting advice grounded in reality and while sometimes leading edge, never bleeding edge.

EET&D: What's next big thing on the technology horizon?

Brown: The Internet of Things (IoT) is in its infancy but already having a huge impact on the electric grid. We've seen great progress in grid automation and controls that improve efficiency and reduce emissions. We are making huge strides in device interconnectivity and data transparency. These advances are making things like distributed energy resources (DER) and microgrids possible. It's enabling consumers, or consumer driven algorithms, to make more informed decisions about their energy usage, thus lowering costs and increasing convenience. I don't think we have even touched the surface on the IoT front.

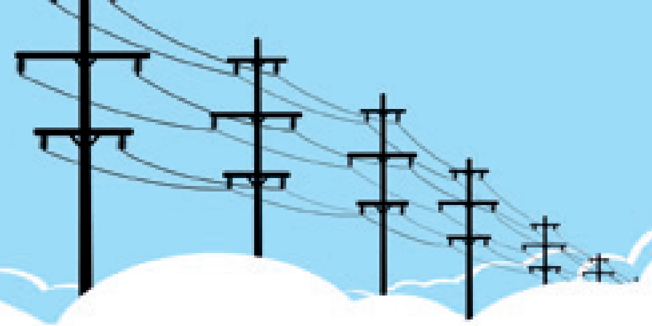
Malme: If I had to pick one area, it would be distributed energy resources. This packaging of generation assets, consumer empowerment technologies, building and home automation, batteries, renewables and market driven transactional capabilities is going to change everything. This impact will be felt here in the U.S. and even more so in emerging international markets.

Weigand: My pick is perhaps based on a more personal level. Addressing the challenge of making employees more productive and focused in the face of an overwhelming and growing stream of information and sources. Everything from smart phones to big data applications is making it ever harder for an individual to not only keep up, but sort through it all for what really matters. This challenge is going to get worse before it gets better.

Lander: For me it's going to be critical to see if technology can somehow better address the aging workforce problem. You can automate the two grids all you want, but ultimately someone has to install and maintain the basic infrastructure, as well as transact and enter those transactions into recording and implementation systems. While technology can streamline that process to make it more efficient, to date technology can't climb a pole, turn a wrench, or effectuate and communicate a transaction. It's going to be a huge issue, if it isn't already, to find skilled operations, transaction, and field labor that not only has the technical skills but also the market rules and technology skills.

EET&D: What does a utility look like ten years from now?

Weigand: I foresee a lot more consolidation. The need for economies of scale, leveraging field labor over geographic regions, and spreading investments across a larger customer base are some of the keys that will define the winners and losers.



Malme: Some won't look that much different than they do today, especially the very slow adopters of technology.

Brown: For those utilities that are creating new businesses under their nonregulated subsidiaries, I envision that they will become the power market majors of the future.

EET&D: Last question for Peter, where do you see Skipping Stone in the future?

Weigand: The first twenty years has been an interesting and exciting journey. The daily challenge of balancing experience against staying on top of new developments and then combining the two for the benefit of our clients is what makes this job both fun and rewarding.

I never set out to make Skipping Stone into a consulting giant, rather the goal was to provide real value for clients and at the same time attract talent to our team who enjoy doing that and are good at it. By nature that model doesn't lend itself to becoming too big as I don't think a big consulting company can sustain our model. This is why I haven't ever considered selling the company to one of the big consultancies. As long as clients will have us and I'm running the company, I don't envision changing our model in the future.

EET&D: Gentlemen, we can't thank you enough for taking the time to talk to our readers. Your take on the future of energy is at once fascinating and enlightening.

GREEN OVATIONS

Innovations in Green Technologies

Driving the Grid Forward:

Best Practices for Utilities to Prepare for the Electric Vehicle Boom

By Colin Gibbs

Introduction

With international goals to limit global warming levels to 2°C or less over the next several decades, the electric vehicle market has the wind at its back. However, despite lower operating and maintenance costs, the higher upfront costs of EVs can be a barrier to adoption. The answer to this challenge has resulted in everything from pooled purchasing programs to rebates to tax breaks, all of which are contributing to an increase in EV sales, with several major car manufacturers including Tesla, GM, Volkswagen and Nissan announcing the roll-out of hundreds of thousands more EVs in the next several decades.

According to the International Energy Agency (IEA), electric vehicles accounted for more than 400,000 cars on the road in the United States in 2015. While predictions for the continued growth of the EV market span anywhere from "one third of new car sales globally by 2040," according to Bloomberg New Energy Finance to "1 billion by 2050," according to the IEA, to "1.4 million in 2020," according to the 2015 EV Industry Insider Report, the bottom line is clear: Utility planners have a big wave of changes ahead of them in order to prepare for the EV boom.

A greater demand on the grid might seem like a potential problem at first glance, but with EV batteries now capable of storing 30kWh of electricity, enough to power an average U.S. residential home for one day, the grid may benefit from these eco-friendly vehicles in ways never imagined before. As they anticipate impacts to the grid from the growing electric vehicle market, utilities should keep the following best practices in mind.

Creating Effective Incentives

Just as utilities offer incentives for efficient equipment and building retrofits, rebates on electric vehicle supply equipment (EVSE) and the vehicles themselves are an important driver of consumer demand. Just like utilities once forged new paths with home improvement retailers like Home Depot and Lowes to create better energy efficiency programs, utilities can partner with EV manufacturers and dealerships to design programs and incentives that benefit both the grid and the consumer. Partnering with vehicle manufacturers also enables utilities to better anticipate the economic and demographic makeup of new EV purchasers, which can greatly aid in grid and infrastructure planning.

Some examples of utilities already executing this include PECO who offers rebates for EVs directly to residential customers, while Indianapolis Power & Light and Jacksonville Electric Authority offer purchase rebates on fleet vehicles for business customers. Puget Sound Energy (PSE) offers reduced cost electric vehicle supply equipment (EVSE) to commercial customers. Recent regulatory changes in a variety of states, most notably California, suggest that the opportunity for utilities to rate base (earn a regulated return) investments in EV charging infrastructure will become more commonplace. San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE) are in the midst of installing a combined 5,000 charging stations across Southern California through the Vehicle Grid Integration Program and Charge Ready Program, respectively. While some major differences regarding direct utility ownership of the equipment exist between these two programs, the premise of both is that the California Public Utility Commission (CPUC) will allow cost recovery of these large investments in new EV charging infrastructure.

Utilities should also look toward local and state public partnerships to offer convenient, ancillary incentives such as access to HOV lanes, reduced rate or free city parking and lowered vehicle registration costs for EV owners. All of these benefits can be part of the complete economic value proposition marketed to customers, while also providing utilities with a unique opportunity to shape the geographic load profile of EV owners.

Rate Design

Utilities should consider different types of variable rate structures that encourage EV owners to charge their vehicles when demand for energy is low and excess capacity is high. A recent report from Rocky Mountain Institute titled "Electric Vehicles as Distributed Energy Resources" noted that "early pilot projects are demonstrating that EV-charging load profiles can be effectively shifted to off-peak hours under time-of-use pricing if the off-peak pricing is around one-third of the on-peak price."

With these sorts of rate structures in place, customers can choose to pay more during certain times of day to charge their vehicles or be rewarded for charging vehicles during off peak times. Many utilities around the country, such as San Diego Gas & Electric (SDG&E), ConEdison, and Arizona Public Service (APS) have introduced time-of-use (TOU) rate schedules for customers with EVs. In addition to creating price signals that encourage charging at times most beneficial to the grid, these initiatives also allow utilities to separately meter the charging station, providing valuable insight into the charging behavior and use of EVs across their service territory.

While most TOU rates focus on encouraging residential customers to charge their vehicles overnight, Rocky Mountain Institute suggests that "new emphasis is being placed on workplace charging in some jurisdictions, notably California and Hawaii, where abundant solar generation makes daytime charging especially attractive." Daytime workplace charging would also allow utilities with excess renewable generation to absorb that capacity across a distributed network of EVs rather than curtailing it. It is easy to envision how such initiatives could evolve into an energy storage network in the future. EVs could store excess capacity generated in areas with a high penetration of distributed photovoltaic solar (PV) or centralized wind and then be dispatched as a resource during peak events or evening system ramping. This would decrease the need for large investments in centralized gas generation and result in a net benefit to ratepayers.

Pairing EV Efforts with Existing Utility Programs

EVs may not be a traditional energy efficiency measure, but they have the potential to benefit consumers and the utility in many of the same ways. Despite the required grid capacity to charge an ever increasing number of EVs, their proliferation gives utilities an effective way to address peak events, smooth system ramping and even regulate voltage. The flexibility of the EV load requires an extensive amount of customer outreach and education, which is an area where utility offered demand side management and demand response programs have excelled. Providing customers with interactive ways of communicating with their electric provider while proactively managing their energy use, such as through mobile apps and real-time monitoring of charges and rates, are goals that are consistent with many existing utility efforts and can play an integral role in the future of EVs.

Dynamic pricing schemes and demand response options should be offered through online portals and smart phone applications that deepen the utility relationship with customers and increase utility access to customer consumption and behavioral data. These strategies are consistent with utility business objectives to deepen the relationship with customers and increase overall customer satisfaction.

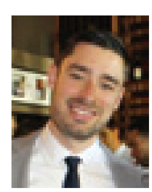
Conclusion

As vehicle costs come down, battery range increases and public policy objectives continue to push EV adoption, the electrification of the transportation sector is inevitable. Electric utilities will be instrumental in this transition and EVs could be a boon to the utility business while also offering immense public benefits.

Utilities should continue to build the infrastructure necessary to integrate the expected growth of EV owners either through third party partnerships or direct investment in charging equipment. Business and multi-family customers will offer big opportunities to provide charging access to large numbers of customers. Dynamic pricing options, such as time of use rates will allow utilities to influence the load shape of the EV population while offering critical economic incentives to drivers. Incentives of convenience, such as HOV access, free parking and reduced cost vehicle registration will enhance the ease of transition for customers while utilities continue to offer rebates on charging equipment and vehicles for both residential and commercial fleet customers. Lastly, utilities should integrate EV efforts with existing energy efficiency, demand response and solar programs.

Consider all of these trends in your distribution planning now to get ahead of the EV boom.

About the Author



Colin Gibbs is the Director of Business Intelligence at CLEAResult, which designs and implements energy efficiency programs for utilities. He leads a portfolio of technical consulting contracts, analytics projects and pilot initiatives. Colin has spent 10 years in the demand side management and demand response industry, designing and implementing residential and commercial programs for over 40 utilities around the US. He is based in Portland, OR.

From Research to Action

Laying the Foundation for Smart Inverters

By Dr. Guohui Yuan and Dr. Aminul Huque

This story was originally published as part of the U.S. Department of Energy's SunShot Initiative series of success stories in December 2016

Advanced inverters are a critical enabler of high solar photovoltaic (PV) penetrations because of their smart functionalities and ability to maintain a balanced grid. Deploying advanced inverters with smart grid capabilities in the field, however, is easier said than done. Thanks to the work of the Electric Power Research Institute (EPRI), the solar industry has a solid foundation for both using and improving inverter technology.

As a key component of modern solar systems, inverters convert direct current (DC) produced by solar panels into alternating current (AC), which is then usable by households and businesses. Advanced inverters are an important tool for utilities because they collect data on PV systems and can provide reactive power support to regulate voltage and frequency, enabling grid operators to pinpoint solar production levels and better control how much solar is on the grid.

EPRI's SunShot Initiative project served as an early model to the solar industry, demonstrating not only how to create a smart inverter, but how to test and deploy the technology in the field. EPRI began work on the project in 2011, partnering with solar companies, utilities DTE Energy, National Grid, and Pepco, and the National Renewable Energy Laboratory to create an advanced inverter that is consistent with utility communication system protocols. By establishing an end-to-end open standard protocol based communication with distribution management, EPRI's standards were able to bridge the gap between simulation and deployment.

The EPRI project team conducted rigorous testing at the National Renewable Energy Laboratory's Energy Systems Integration Facility and also at EPRI's Knoxville, Tennessee laboratory to ensure the new inverters would respond to expected commands at the utility scale. This phase gave the team greater confidence that the technology they developed was sound and ready to be tested in the field.

Next, advanced functionalities were implemented and tested on three distribution feeders for different circuit level benefits such as voltage variation reductions, power factor improvements, and loss reduction. The team was able to successfully test the inverters in the field and determine that there is significant value in both autonomous and communication controlled operation of the advanced grid support functions.

The successful lab and field demonstrations enabled the researchers to contribute research that led to amendments—IEEE 1547a-2014 and IEEE 1547.1a-2015—to the Institute of Electrical and Electronics Engineers (IEEE) interconnection standards on distributed energy resources. These amendments create inverter testing protocols and procedures, which give inverter manufacturers industry-accepted standards to guarantee their products and enable broader utility use.

EPRI's field testing also yielded lasting relationships with utilities. In concert with their research project, EPRI collaborated with additional utilities on both the design and demonstration phases, helping to broaden industry participation. These collaborations enabled EPRI to ensure a variety of inverter manufacturers and PV plant/feeder situations, providing greater learning opportunities and strengthening their research.

From Research to Action

In addition, one of the utilities EPRI collaborated with, National Grid, hosted two PV demonstration sites in Massachusetts as a part of its program to own and operate solar. As a result of the successful demonstration, National Grid expanded its program and now expects to own and operate up to 20 megawatts of PV plants and conduct further advanced inverter research with the help of EPRI. Furthermore, EPRI leadership awarded the collaborative team with the prestigious Technology Transfer Award for their collective contributions to the IEEE national standards and requirements for communicating with smart inverters.

Prior to EPRI's project, the value of smart inverters was only seen on paper through modeling and simulation exercises. Without a demonstration, there was no way to see how inverters would interact with other technologies and respond to real-world grid fluctuations. EPRI's research and industry leadership established the use of advanced inverters as we know them today, helping utilities better incorporate solar into their operations and planning while also minimizing grid integration costs. Learn more about the SunShot Initiative's Systems Integration program and EPRI's training, grid integration, and PV reliability projects with SunShot.

About the authors

Dr. Guohui Yuan is the program manager for the systems integration subprogram at the U.S. Department of Energy SunShot Initiative. His team supports research, development, and demonstration of technologies and solutions that enable the widespread deployment of solar energy on the nation's electricity grid. Dr. Yuan has been supporting the SunShot Initiative as a technical advisor since 2011. Previously, he held several key positions at industry-leading clean technology startups, including CURRENT Group, GridPoint, and WaveCrest Labs. He is a recognized thought leader, has many technical publications, and holds nine patents.

Dr. Aminul Huque is principal technical leader in the Integration of Distributed Energy Resources group at the Electric Power Research Institute (EPRI). His research at EPRI focuses on smart inverters, interconnection standards and grid codes, solar photovoltaics, energy storage, load integration, and microgrids. Dr. Huque is leading the IEEE P1547 voltage regulation subgroup and is an active member of the IEEE 1547 working group. Huque earned a Master's degree from Imperial College London in 2003, and a Ph.D. from the University of Tennessee at Knoxville in 2010.

The Internet of Things Starts with the Grid of Things - Part 2

By Zac Canders

Unbeknownst to me, in the Sept./Oct. 2016 issue of Electric Energy T&D Magazine, Ryan Zaczynski, DataCapable's Data Science & Analytics Director, gave away a big secret. My vision of the Future Grid:

"I want my toaster to talk to my Utility."
Zac Canders

We've all heard about the benefits of interoperability and Ryan's piece was a great start. In his tell-all editorial, Ryan set the stage for the Grid of Things; a simple framework by which interoperability of sensors, data, systems, telecommunications, protocol, utility teams, vendors, and the customer becomes a reality. The ink was barely dry on the press, and the editors of Electric Energy T&D asked for more insight. If Toaster-to-Utility communications were moving from the realm of 'possible' to 'inevitable' then the logical question is "how".
So as 2017 kicks-off, it's appropriate to provide some inspiration and recommendations for anyone out there that wants to be part of the interoperability story. **A step-by-step guide on how to embrace interoperability**.

BECOME INTEROPERABLE

Grid Interoperability is the proverbial jam of my demand-response made toast! Across these past few years' vendors and utilities across the World have joined together to improve service reliability and embrace the dynamic needs of electricity customers. Interoperability is a challenge that is uniting power system engineers, utility professionals, software developers, and energy executive teams. Together we are solving complex utility problems and driving change.

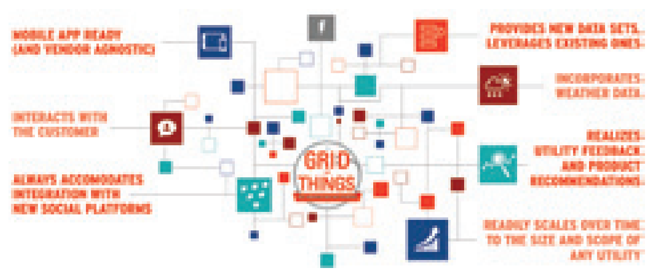
And as my travels have taken me to nearly every corner of the planet, I've had the opportunity to witness a common, and much-needed, theme emerge. **Interoperability is Easy**.

Have you ever found yourself asking…

Why can't utilities share their data in real-time with other utilities?

Why can't product and service providers and emerging startups seamlessly access utility data?

Why isn't it easier to collaborate with utilities and other product and service providers?



HOW TO BECOME AN INTEROPERABILITY LEADER

Back in the days of 2014, no utility on the planet could share their outage data via a standard. Please go make a cup of coffee, sit down, and reflect on this for a minute. In a world connected by a whole lot of wires the one thing we, the utility industry, couldn't do was share outage data during disasters or large-scale grid events.

How did we build a grid that couldn't share data? I pointed a finger of blame at utilities, regulators, and even the vendors supporting the industry. Soon I realized, it wasn't the fault of these parties. If the Grid was going to change, then the people supporting it would need to collaborate. It was time to take the first step in the journey of interoperability.

Step 1: Build the Collaboration

Utilities across the planet have sought solutions to provide holistic views of damages and grid events to support each other with the sharing of crews and assets during times of natural disaster. The value is very clear:

- Energy managers for grocery stores across the World have dreamt of the day that outage data could help them identify when to provide mobile generation services or contact donation organizations to prevent food spoilage.
- Emergency responders on every continent (minus Antarctica) have been begging for ways to understand when and where to stage shelters and supporting crews during a crisis.
- Insurance firms have dreamt of ways to minimize and predict the impact of large weather events, thereby mobilizing adjusters faster and reducing the burden of breakdown insurance on their clients.

The first step in every interoperability journey is getting support from vendors, utilities, customers, regulators, and associated energy stakeholders. In the example of getting outage data shareable, leaders from across the World united, built a forum to discuss the plan of attack, and assigned roles and responsibilities. Together the Collaboration ensured that security, technology architecture, standards, feedback, and goals of interested parties were accounted for.

Step 2: Put an API on It

> *Think of an API as a contract. It details the exact structure of request and response. It provides a documented, upfront approach on how to work with data and will remain constant over time.*

Once you have your interoperability use case, the next step in the journey is Step 2: Put an API on it. Specific to Step 2, interoperability isn't bolted on, it needs to be part of the entire journey. By providing an Automatic Programming Interface (API) you are doing two things:

1. **You are embracing the core fundamentals of interoperability.** You are agreeing to share your data via standards and best practices in software development. You believe in the power of making your data available to others:
    - Product and service providers no longer compete on data but rather the information that can be derived.

2. **You are actively joining the club that wants to kill vendor lock-in:**
    - Gone are the days where siloed systems and solutions are embraced (or even enforced) at utilities and within product and service organizations.

In the outage data example, the Collaboration started an interoperability party. By spinning an interoperable tune, others showed up to the dance. Additional utilities, vendors, and interested parties from across the World have started getting involved in both the sharing and requesting of outage data via the API. By following the guide detailed here within, the Collaboration made interoperability easy (**Step 1**) and expanded the value by having an API (**Step 2**).

The outage data standardization leveraged the Common Information Model (CIM), a standard developed by the electric power industry that has been officially adopted by the International Electrotechnical Commission (IEC). The outage standard provides real-time, utility-sourced, outage information from across the planet.

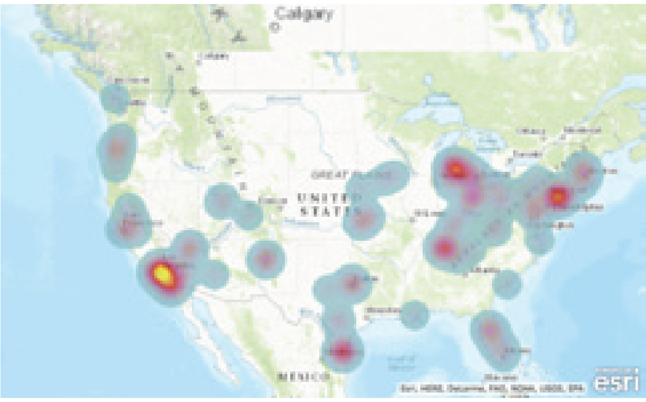


Image 2: Outage events from across the World can be easily visualized in a myriad of applications. All provided by the Collaboration that embraced interoperability.

Step 3: Actively Support Interoperability with Standards

Embracing **Step 3: Actively Support Interoperability with Standards** may be the hardest (and most time consuming) part of the journey. While I've spoken to how true change takes passion and an API, Step 3 and **the role of standardization is a key component that can't be overlooked.**

In Step 2, I spoke of the International Electrotechnical Commission (IEC) standard for outage data shareability. By leveraging the power of the CIM standard (Common Information Model), a passionate and dedicated group of utility professionals and leading software firms did something truly remarkable. The collaboration shared outage data in real-time across each other's systems and service territories via a standard. As of January 2017, seven utilities and ten globally recognized product and service providers have embraced the Outage Data Initiative (ODI) standard. **So who lead the charge on standardization?**

You guessed it!!!

The Collaboration (Step 1). This included technical experts, geo-spatial leaders, software developers, engaged utilities, passionate governmental organizations (including the United States White House Office of Science and Technology Policy). This included leading utility experts that supported and designed the API, authentication, security and IT architecture.

If the Collaboration was going to provide the World with global power outage data, it had to align with **Step 3: Actively Support Interoperability with Standards.** Sure, the Collaboration could have shared outage information without a standard. But by embracing a standards-based approach, the Collaboration ensured that the current and future users of this data would benefit from the well-defined common set of objects and relationship represented in the outage standard.

While **Step 3: Actively Support Interoperability with Standards** was the hardest part of the journey. The financial value for utilities and their customers is extremely clear. In September 2016, an electric utility in the northeast United States asked a new market entrant to include standardized outage data in their application.

The integration effort took a remarkable ***14-minutes*** to have real-time outage data visible inside the vendor's application. All provided via a standards based approach to interoperability.

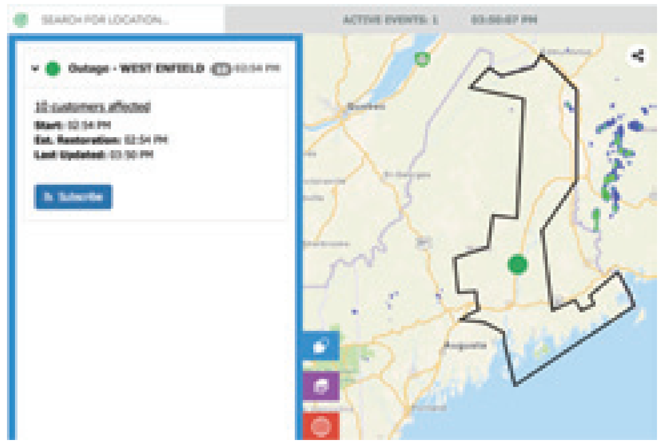


Image 3: Standardized Outage Data as overlaid with weather imagery.

THIS GRID OF THINGS STORY HAS JUST STARTED...

We're all pushing to make the grid safer, more reliable, and ready for renewables integration. Hopefully, you are as excited as me to join this Grid Interoperability journey. I personally want each and everyone of you to get involved. Send me a note at *Zac@DataCapable.com*.

Collaboration, standards, and APIs will drive the next generation of utilities and it won't happen without your involvement. Across the coming months, the Collaboration mentioned in this article will be supporting a five-part editorial series on "The Grid of Things" for Electric Energy T&D. It will conclude in an industry first (and extremely exciting) demonstration that's going to require your help.

About the author

Zac Canders is the Co-Founder and CEO of DataCapable. In this role, he leads DataCapable's worldwide delivery of the UtiliSocial platform. The first customer engagement system designed for utilities. He is passionate about the reliability of the global grid and "Connecting to the Customer of 2017". He has also authored numerous papers and extensively supports interoperability initiatives.

Advantages of Hybrid Wireless Field Communication Networks for Smart Grids

By Bert Williams

To reap the reliability, efficiency, security and customer satisfaction benefits of building a smarter grid, electric utilities are deploying smart meters, intelligent electronic devices (IEDs) and other digital apparatus along distribution feeders and in substations. Electric utilities are also equipping field workers with laptop, tablet and handheld computers. Coupling these field devices with specialized computers and software in substations, plus enterprise software applications in utility data centers is a sound business and technical strategy. Why? Because it enables the operation of valuable utility applications such as automated metering infrastructure (AMI), substation automation, distribution automation, outage management, and automatic load shedding. This coupling also facilitates the ability to manage alternative energy sources.

While devices and application software get the bulk of the publicity, an oft-overlooked element – two-way communication – is required to make the smart grid smart. As shown in Figure 1, two-way communication enables intelligent devices in the field to provide data to applications running on computers in substations and data centers.

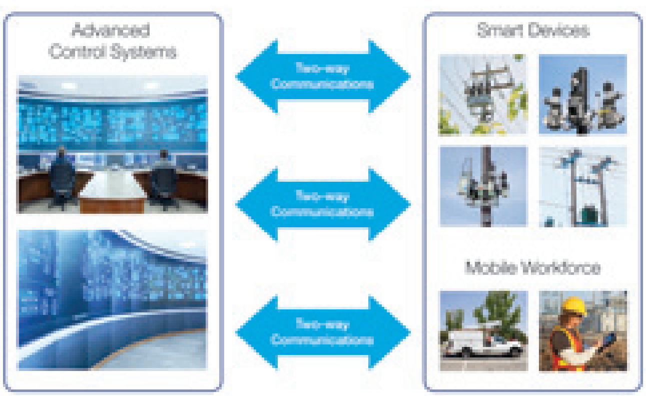


Figure 1 – Two-way Communication.

Because electric utility distribution grids can cover vast areas, wireless field communication networks are often the only technically and economically feasible choice. But wireless comes in a wide variety of flavors – broadband mesh, narrowband mesh, broadband point-to-point (PTP) and point-to-multipoint (PTMP), narrowband PTP/PTMP and cellular data services, to name a few. Which one is right for an electric utility's field communication network?

The answer is that one size doesn't fit all. It depends on various factors. These include: the number of assets to be connected to the field communication network in a given area, the requirements of applications to be run over the network, the topography of the utility's service territory, and more. In fact, different wireless technologies may be required in different areas of the utility's field communication network.

Utility Communication Network Architecture

To understand why one size doesn't fit all, first consider the architecture of utility communication networks. Most utilities implement a two- to four-tier smart grid communication network architecture, depending on the specific applications they plan to deploy. Each tier places different requirements on the communication network. The tiers are defined as follows and illustrated in Figure 2, on the following page.

- Tier 1: This is the utility's core Internet Protocol network, which often connects many of its distribution substations. This tier is generally implemented with fiber. In areas where Tier 1 connectivity is required, but it's economically or technically infeasible to deploy fiber, broadband PTP/PTMP is often used to extend the reach of the fiber network.
- Tier 2: The Field Area Network (FAN) fills the gap between the core Tier 1 networks and devices, as well as personnel, in the field. Substation automation devices, distribution automation devices, AMI collectors, and mobile workers equipped with laptops, tablets or handhelds connect to the FAN. FANs are generally implemented with a combination of broadband wireless mesh, narrowband PTP/PTMP and cellular data links. Endpoint connections to the FAN can use wireless, wired Ethernet or serial links.
- Tier 3: The Neighborhood Area Network (NAN) includes smart meters and AMI collectors. The NAN is generally implemented using narrowband wireless mesh or cellular data. When a broadband wireless mesh network is used to implement the Tier 2 network, the AMI collectors in the Tier 3 network are generally co-located with and connect to the broadband mesh routers that form the Tier 2 network. The NAN may also provide the communications interface for the Home Area Network.
- Tier 4: The Home Area Network (HAN), is usually implemented using ZigBee™ or HomePlug™ technology. This provides connectivity to smart grid devices, applications and displays inside homes and businesses. If supported by the AMI system, HANs can connect to NANs via the smart meters deployed on the customers' premises. Otherwise, the HAN will connect to the utility's operations center via the internet.

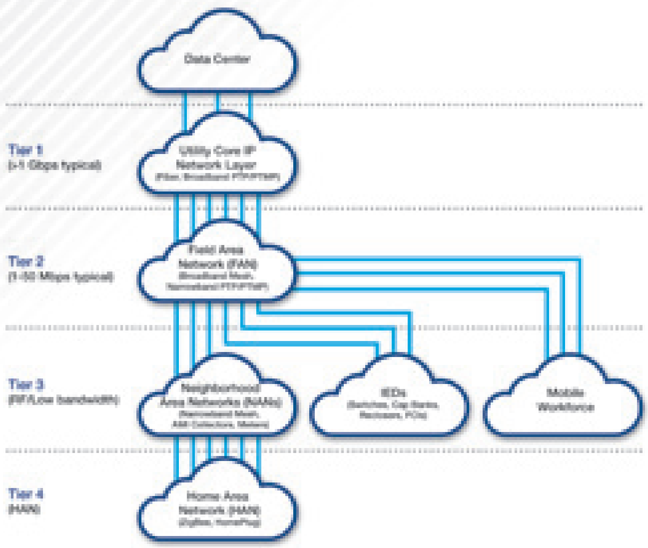


Figure 2 – Typical Utility Communication Network Architecture

Different Topography, Different Technologies

As can be seen in Figure 3, the best wireless communication technology choice varies with service area topography as well as with network tier, especially in the Tier 2 FAN.

In most areas, fiber, augmented by broadband PTP/PTMP as required, is the choice for the Tier 1 core IP network. An exception is ultra-rural areas, where the utility does not have enough assets or customers to economically justify a private broadband connection. In these cases, when coverage is available, a public carrier wireless data connection is recommended.

For the Tier 2 FAN, broadband wireless mesh offers the best reliability and performance. Broadband wireless mesh is best suited for dense urban, urban and some suburban areas where the number of utility assets and customers per square mile is high enough to make it an economical choice. In some areas, the effective range of broadband mesh communications can be extended by the use of directional antennas, as opposed to the omnidirectional antennas generally used. However, in suburban and rural areas where density of utility customers and assets is lower, broadband mesh may no longer be economical. In this case, narrowband PTP/PTMP is generally the best solution, although broadband PTP/PTMP may be deployed if more bandwidth is needed. As with the Tier 1 network, ultra-rural areas may not have enough assets or customers to economically justify a private communication network connection. If coverage is available, use of a public carrier wireless data connection is recommended.

Narrowband mesh is the technology of choice for the Tier 3 NAN in almost all cases. Even in ultra-rural areas, narrowband mesh may be economically feasible due to the longer range supported by the lower frequencies used by the technology. In rare cases, where cellular coverage is available, cellular data connections may be deployed in the meters themselves. However, it is more likely that narrowband mesh will be used to connect the meters to the AMI collector, and that the collector will be backhauled by a cellular data service. This is shown on the right-hand side of Figure 3.

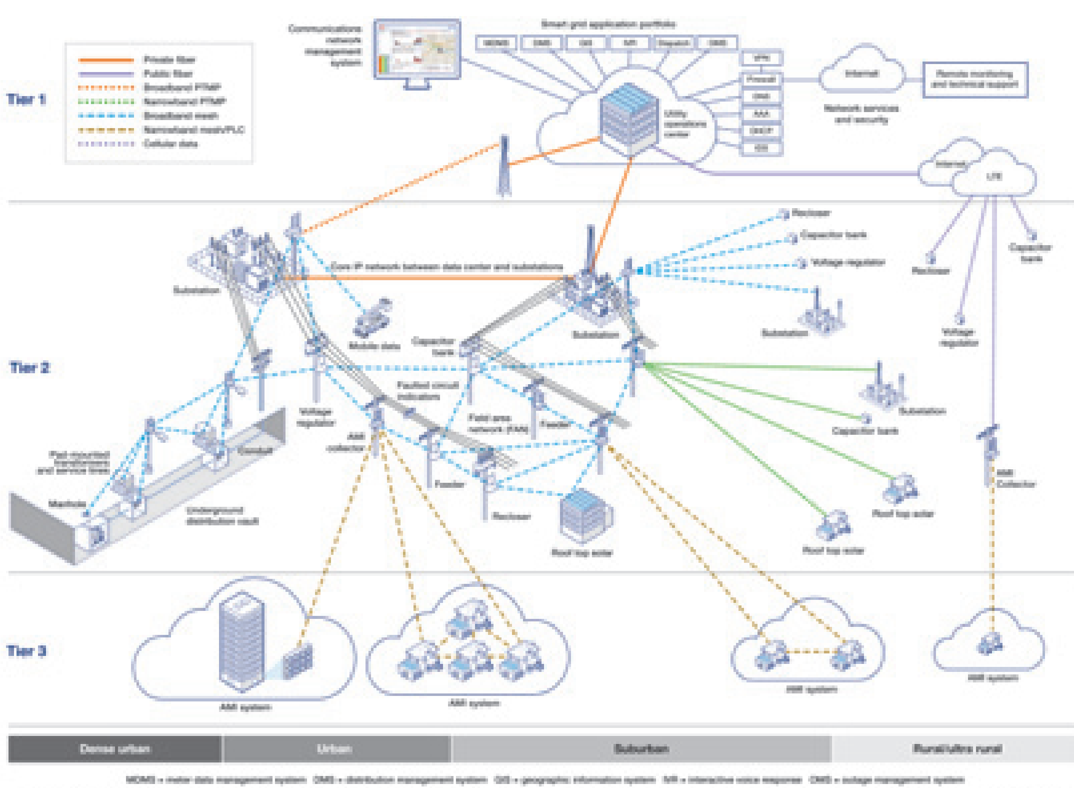


Figure 3 – Recommended Implementation of Utility Communication Network Architecture Technology Fit

Different wireless communication technologies have different strengths and weaknesses. These are summarized in the chart in Figure 4.

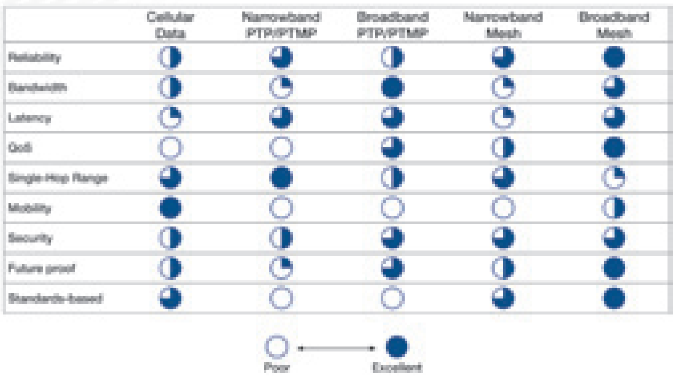


Figure 4 – Wireless Communication Technology Strengths and Weaknesses

Some characteristics, such as high reliability and solid security, are desirable in all networks. Other characteristics are important in some cases but not others.

For example, high bandwidth and low latency are important for Tier 1 and Tier 2 because these tiers aggregate traffic from the lower tiers. In addition, they must support the needs of even the most latency-sensitive applications. As a result, broadband technologies are a good fit at these tiers.

On the other hand, for metering applications, bandwidth and latency are less important. Therefore, narrowband mesh is a good fit for Tier 3.

When providing communications to rural and ultra-rural areas, long single-hop range is a key to economic feasibility. Thus, narrowband PTP/PTMP and cellular data are best suited for rural and ultra-rural areas. Conversely, they are less often used in dense urban and urban areas, where technologies with less single-hop range can be used to economically construct networks.

A summary of the technologies with the best fit by network tier and topography appears in Table 1:

	Dense urban	Urban	Suburban	Rural	Ultra-rural
Tier 1 core IP network	Fiber	Fiber, Broadband PTP/PTMP	Broadband PTP/PTMP, Fiber	Broadband PTP/PTMP, Cellular Data	Cellular Data
Tier 2 field area network	Broadband Mesh	Broadband Mesh	Broadband Mesh, Narrowband PTP/PTMP	Narrowband PTP/PTMP	Cellular Data
Tier 3 neighborhood area network	Narrowband Mesh	Narrowband Mesh	Narrowband Mesh	Narrowband Mesh	Narrowband Mesh, Cellular Data
Tier 4 home area network	ZigBee, HomePlug	ZigBee, HomePlug	ZigBee, HomePlug	ZigBee, HomePlug	ZigBee, HomePlug

Table 1 – Best Fit Technologies by Network Tier and Topography

Many Technologies, One Network: The Unifying Role of Communication Network Management

With different tiers and multiple technologies spread across a large geographic area, it's tempting for a utility to design, implement and operate many different field communication networks. This thinking can, however, lead to operational inefficiency, poor network reliability and security, or worse when, for example, it results in different networks having different security policies.

A communication network management system (NMS) can play a unifying role, providing visibility and control across the entire network, regardless of location and technology deployed. This holistic view enables utility operators to quickly pinpoint and address key health and life cycle challenges that are major sources of inefficiency and risk. Key requirements for such an NMS include providing network-wide visualization tools for fault configuration and performance management from a single console. The combination of rich data collection at the edge of the network and powerful analytics at the core deliver unprecedented visibility into network operation, simplifying management, improving operational efficiency, and accelerating problem/resolution time.

Conclusions

One size doesn't fit all when it comes to utility field communication networks. A wide variety of wireless communication technologies are available. Utilities should use this to their advantage, deploying the best-suited technology based on factors such as network tiers, population and asset density, topography of the service territory and application requirements.

However, technologies shouldn't mean different networks. The various technologies should be blended into a single, hybrid network. A robust, multi-technology communication network management system can unify various wireless – and wired – communication technologies into a single network with end-to-end visibility and control.

About the author

Bert Williams is the Director, Global Marketing for ABB Wireless and brings 30 years of experience in successfully leading the marketing organizations of networking companies. Mr. Williams was Vice President of Marketing for Tropos Networks from 2002 to 2007 and returned to the company shortly before its acquisition by ABB after working as an executive marketing consultant for four years. Prior to Tropos, Mr. Williams held senior marketing positions at Alteon WebSystems (acquired by Nortel Networks), Qualix Group, SynOptics Communications (part of Bay Networks), Synernetics and Advanced Micro Devices. Mr. Williams holds a BS with University Honors in Electrical Engineering from Carnegie Mellon and an MBA from Harvard Business School.

Building a Foundation to Move Your Utility Grid Modernization Strategy Forward

By Jennifer Ahearn

Grid Modernization encompasses a vast variety of different functionalities, capabilities and technologies, which can seem overwhelmingly complex for a utility embarking on a Grid Modernization journey. For the purposes of context, let's start with a common understanding of what Grid Modernization means in this discussion. While almost every project impacting the grid could be considered a modernization, in this article I am referring to the proper noun, Grid Modernization. This embodies changes to legacy distribution systems as well as the deployment of new technologies (e.g., distribution management systems, high speed communications, advanced sensors, energy storage) to provide the functionality and capability needed to support new distributed energy resources (DER) and more customer-centric interactive marketplaces that will enable a cleaner, smarter energy future.

Many utilities in the US have been embracing core Grid Modernization goals for years: cleaner, safer, and more reliable energy service. Innovative utilities, even those without significant regulatory pressure, recognize the importance of further future preparation. Faced with increasing penetration of distributed energy resources and increased stakeholder engagement, utilities are feeling the pressure to develop a strategy that prepares them for this transition and enables pursuit of the right opportunities for new operational and business strategies. They are now pursuing emerging opportunities to better engage customers, utilize DER, and deliver innovative energy products through new markets. But if these new Grid Modernization goals aren't already a part of a utility's corporate strategy, where do they start?

For the past three years, we have been working with utilities in several states on Grid Modernization strategy and technology implementation. The following explores a representative approach, the "Line of Sight" methodology, which utilities have found incredibly beneficial in establishing clear links between desired outcomes, core functionality, and foundational technology.

Creating a Line of Sight

Today's utilities are improving operational performance through continued investments. However, to ensure alignment with long-term needs, these investments must also be viewed with a perspective towards future strategic goals around Grid Modernization. The modern grid will rely on a full suite of technologies that improve operational performance, enable integrated planning, and support a higher degree of customer engagement. At the same time, the complexity of the business and regulatory landscape will require a higher degree of strategic planning and risk management.

Source: BRIDGE Energy Group

The Line of Sight methodology helps utilities and regulators establish a framework for developing, evaluating and communicating Grid Modernization technology portfolios. The framework is designed to create links between strategic objectives identified by utilities and policy makers and specific technology implementation projects. Adhering to this methodology can help utilities evaluate numerous technologies and systems available within the context of future goals as well as identifying key interdependencies between program initiatives, technologies, and business processes.

Strategic Objectives

An effective Grid Modernization program starts with identifying the high-level goals and objectives that will define the program's success. In some states, there are already well-defined policy goals that can be used as foundational principles to begin building a successful program. For example, California, New York and Massachusetts are leading the country with statewide initiatives such as New York's, Reforming the Energy Vision (NY REV). These initiatives are motivating utilities to become more customer-centric through data and knowledge sharing, 3rd party engagement and market enablement as well as the development of innovative energy products and services. By aligning corporate objectives with key foundational principles, utilities have clearly defined objectives to begin shaping their Grid Modernization plans.

In environments where Grid Modernization policy is in its earliest stages, utilities may have an opportunity to help shape policy proactively. By taking their corporate strategic objectives and applying a Grid Modernization lens, utilities can begin to make foundational investments in their infrastructure and technology that will benefit the customer -- while proactively engaging the other parties. For example, while the complexities of a dynamic energy marketplace continue to emerge, the simpler principle behind that marketplace is the enablement of more informed customer knowledge and choice. Not only is this idea more tangible, but also it is likely already aligned with a utility's corporate vision and mission. Having clearly defined strategic objectives are not only beneficial for the creation of an actionable vision, but allow for simpler and more effective communication when articulating the plan to stakeholders.

Capabilities, Functionality and Enabling Technologies

Once objectives have been established, utilities can then begin the task of applying a methodical approach to break down specific capabilities and functionalities required to achieve objectives. Clearly defined capabilities and functionalities are critical to determine which technologies will have the most efficient and effective impact on current and future operations.

In the case of enabling customer knowledge and choice, a utility may decide that to meet that objective it will require more granular energy usage data, the ability to analyze that data to develop compelling products and services, and a means to provide those options to the customer. While there can be multiple technology solutions that meet an array of requirements, mapping a technology decision back to specific capability, functionality, and strategic objective will enable leaders to secure buy-in from all stakeholders when considering infrastructure and operational investments.

Project Portfolio

Today's technology deployment plans for Grid Modernization are typically defined for five to ten years. Communications systems, smart metering, and distribution automation can take several years to deploy. Moreover, interdependencies between different systems can require a high degree of planning and coordination. Not every utility may be positioned to take on such a large-scale implementation all at once. However, developing even just a single objective using the Line of Sight methodology provides an opportunity for that objective to be baked into existing operations or business initiatives. At a minimum, this will not only benefit the customer and the grid, but also give credence to a utility's future Grid Modernization proceedings when the time comes for action.

In addition, the cost of Grid Modernization plans can run into the billions of dollars, requiring careful choices about what to implement and when. Objectives, capabilities, functionalities and technologies can be woven together to develop a portfolio of projects, which become the bones of a well-thought out, integrated Grid Modernization plan. A portfolio approach enables utilities and regulators to evaluate the costs, benefits, and business cases of different scenarios and program options.

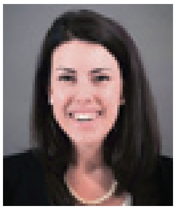
Modern Grid Benefits

Benefits realization is critical to the long-term success of Grid Modernization. In the past, most technology investments were carefully analyzed before deployment, but not after. Establishing a clear program for quantifying pre-and post-implementation performance metrics and benefits helps ensure that outcomes align with objectives. In the case of evaluating customer empowerment goals, utilities should look to program adoption and participation rates of new offerings and services, even looking outside of the industry to create benchmarks for those evaluations. The utility should also consider what qualitative benefits customer empowerment has on the smarter, cleaner future vision of the utility, and the societal benefits that come with it.

Taking Action

Given its fluid and evolving nature, Grid Modernization is not a pursuit that can be addressed in one fell swoop, nor should it be. While the Grid Modernization influence is moving into different areas of the country at different rates, all utilities have an opportunity to take action and be a proactive party in moving the future vision of the utility forward. By using a methodical, rigorous process to facilitate a logical, pragmatic approach, utilities large and small can develop right-sized initiatives that benefit their customers, their regulators and their business.

About the author



Jennifer Ahearn is an Associate Consultant at BRIDGE Energy Group. She has worked on multiple Grid Modernization efforts. Most recently, Jennifer has worked with a leading utility in New York to support the visioning of the Distributed System Platform and required foundational technology to execute their overarching grid modernization strategy and ensure alignment with both state legislation and the utility's strategic business goals.

THE BIGGER PICTURE

BY WILL FELLERS

Key Elements in a Modern Transmission Vegetation Management Program

Vegetation failure is one of the leading causes of service outages, according to data from utilities and other organizations that track utility infrastructure. Not only is vegetation failure a significant safety risk to the public and employees tasked with maintenance, it also exposes utilities to extreme liability when considering catastrophic consequences, such as wildfires and cascading blackouts, and results in increased costs, decreased revenue and a spike in dissatisfied customers.

For more than 100 years, utility vegetation management (VM) practitioners have utilized a variety of data to both optimize and streamline budgeting, schedule prioritization and risk aversion. Since the first power line corridors were constructed, the methodologies for right-of-way (ROW) evaluation have continually evolved, and now the options for remote sensing data collection, high-performance analysis and data interpretation seem almost limitless.

The Evolution of Vegetation Management

Prior to the revised standard laid out by the North American Electric Reliability Corporation (NERC) in 2009, federal requirements for VM activities were mostly voluntary. Very early ROW management strategies focused on manual clearance of fast-growing tree species. To mitigate annual maintenance burdens of dealing with rapid resprouting and regrowth, utilities began to use herbicides heavily in the 1950s. As the adverse effects of herbicides became more clear, utility VM programs halted indiscriminate spraying and transitioned to localized and targeted applications.

In the 1970s, VM programs borrowed sampling techniques from standard forest inventory practices. These techniques enabled them to statistically evaluate their entire ROW system, offering a major leap forward in data quality and accuracy. By combining inventory with forestry-based growth models, managers now had solid statistical evidence to justify anticipated budgetary requirements.

With the rise of desktop computers in the 1980s and 1990s, utilities began to benefit from the inherent powers of data archiving, access, organization and communication. Utility VM professionals also could conduct significant research to learn more about what tree species fail and why, as well as predicting risks based on historical datasets, to optimize prioritization.

The traditional methods used for monitoring ROW vegetation have remained essentially unchanged for decades. Vegetation specialists and foresters either had to do labor-intensive ground-based surveys or conduct quicker, but less precise, inspections from a helicopter. Both methods rely heavily on subjective visual interpretations and introduce potential for significant error. Increasingly, utilities are turning to powerful remote sensing platforms, such as LiDAR and hyperspectral sensors, to get highly accurate spatial data, then leverage advanced analytics to deliver actionable intelligence at a speed and scale never before possible.

After the 2003 Northeast blackout, the federal government passed the Energy Policy Act of 2005, effectively supplanting previous voluntary requirements. The law mandated NERC to solicit, approve and enforce new reliability standards. As a result, utilities were required to modernize their VM programs, ensuring there was up-to-date information available at their fingertips for their entire network, as well as defensible insights on future vegetation status, risks and impacts.

Significant advancements in hardware and software offerings are beginning to change the equation for electric utilities, enabling them to comply with NERC regulations, as well as more easily acquiring and analyzing data that helps them answer business-critical questions. Through a variety of cutting-edge hardware, software and cloud-based solutions, VM programs are now seeing real increases in management velocity, enabling them to meet, and exceed, their goals for user reliability and public safety.

Remote Sensing, UAVs Deliver Advanced Data Acquisition and Efficiencies

All VM practitioners are faced with the responsibility of tracking vegetation and understanding how it interacts with their infrastructure, at both the micro and macro scale.

Regulatory requirements introduced with the introduction of NERC's FAC-003 and FAC-008 drove the need for VM crews to rapidly assess the status of vegetation near hundreds of thousands of miles of high voltage transmission lines. To accomplish this, many utilities adopted laser systems mounted on large fixed-wing and rotary aircraft. This approach is most cost-effective for seasonally addressing large geographic areas containing significant line mileage. But often, VM programs only need to assess much smaller targeted areas, for which mobilization of large-scale airborne platforms does not make budgetary sense.

To address smaller geographic areas, utilities have added unmanned aerial vehicles (UAVs) equipped with purpose-built sensors to the traditional fleet of fixed-wing aircraft and helicopters. These new technologies enable utilities to choose the best, most cost-effective means of data acquisition for each project. UAVs are capable of covering small areas for a very reasonable price, and can be rapidly deployed to collect ultra-high resolution data. Where manned aircraft are suitable for system wide assessments, UAVs are considered an ideal, tailored solution for post-storm assessments, use in areas with challenging terrain, and for targeted 3-D modeling, to name a few applications.

These new remote sensing options reduce or eliminate the need for traditional, time-consuming and labor-intensive field verification, and deliver highly accurate snapshots of transmission infrastructure and encroaching vegetation.

Now let's look at how we can leverage these data collection and analysis technologies to implement a next-generation VM program.

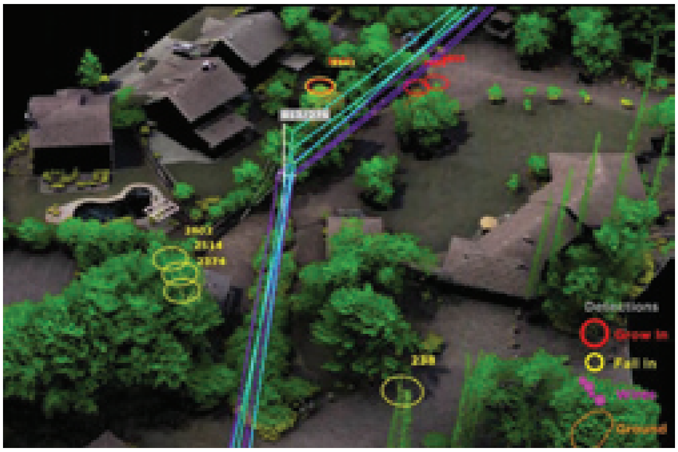
Step 1: Identifying Vegetation Species and Health

A critical first step to addressing vegetation risk is to assess the spatial proximity of vegetation to conductors, considering multiple weather-related and electric load scenarios. This type of analysis offers the descriptive context necessary to catalog all potential threats of electric reliability caused by tree fall, grow-in and spark over risk.

While informative, every utility has institutionalized insights regarding site-specific vegetation threats to their systems, including risks posed by specific species and the prevalence of vegetation health issues.

Using sensors that support multispectral analysis, recent advancements in advanced analytics enable aerial surveys to single out species that pose the most risk in specific geographic areas and identify whether these trees are diseased or dying. This feature reduces the need for field surveys, making foresters and arborists more efficient and targeted as they take action to preserve the reliability of the transmission system.

Vendors of remote sensing data are increasingly providing highly accurate location information for individual trees along utility networks. By combining 3-D geospatial characteristics of individual trees in relation to utility infrastructure with species and health information, VM programs have a powerful new way to assess current and possible future risks to the network.



LiDAR examination of tree risk along transmission corridor

The understanding of species-specific height potentials and growth rates also have a direct consequence when planning pruning or tree removal schedules, developing integrated vegetation management (IVM) strategies, as well as understanding the consequences of extreme environmental conditions including drought, high wind, heavy snow or hurricanes, among others.

Worldwide, massive tree die-offs have been on the rise due to a variety of pathogens and insect infestations. For example, the devastating effects of the emerald ash borer on ash trees, the pine bark beetle, and Sudden Oak Death disease in the West are forcing VM programs to find new ways to rapidly assess and monitor conditions across expansive regions. Hyperspectral sensors now offer the capability of quickly analyzing and assessing conditions for wide areas from the air.

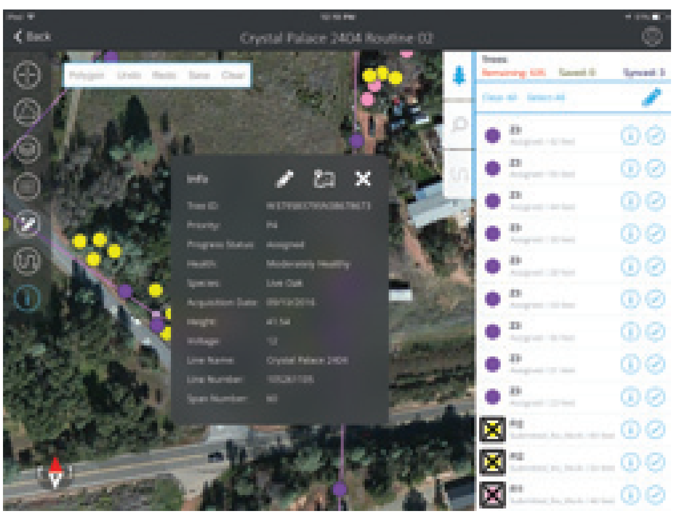
Every utility faces risks associated with dead, dying and stressed trees. These risks often require immediate action and cause the most critical concern to VM programs. New developments in advanced analytics, using aerial data, give utilities access to highly accurate and timely information for individual trees across vast areas. What used to take foot patrols months or years of sampling can now be accomplished in weeks, even days, with highly accurate, full data coverage.

Step 2: Leveraging Predictive and Prescriptive Analytics

Traditionally, VM programs relied on annual or periodic ground-based foot patrols along entire networks to identify hazards needing treatment. VM managers have to subjectively interpret the possibility of future risks in their decision making process. Varying skillsets and priorities often lead to over- or under-management of vegetation along utility corridors, resulting in the realization of unnecessary expenditures or unaddressed risks.

With the adoption of LiDAR-based aerial patrols following the 2003 Northeast blackout, utilities had a powerful new tool to catalog dangers from vegetation. Descriptive analytics derived from LiDAR quickly formed the backbone for many VM programs, describing a wide variety of information specific to vegetation, geospatial location and the relation of vegetation to infrastructure. While informative, it is a relatively simplistic approach suited to describing the current state of vegetation and answering the critical questions related to what, where and how much. Predictive analytics take this data a step further by attempting to predict vegetation status and interactions with infrastructure at some future state.

Going beyond predictive analytics there is prescriptive analytics, which offers managers actionable insights and solutions based on possible outcomes. For example, management teams can use a prescriptive model to optimize ROW treatment plans, prioritize spending based on condition- or risk-based models, incorporate IVM treatment plans, or budget for the next cycle of prescriptions and treatments.



Mobile work management interface for field workers, showing tree species and health information and offering real-time synchronization with other business processes.

Step 3: Cloud-based Access to Real-Time Analytics, Anytime, Anywhere

Historically, analytics from remote sensing data were often delivered as PDF reports, Excel spreadsheets, 2-D digital maps, or even simply the raw data. While informative, this presentation of the data created significant hurdles for VM programs that were overwhelmed by the massive quantity and unorganized nature of the incoming information. The results created frustration and confusion in the VM community and also increased exposure to substantial liability when reported vegetation risks were buried in piles of documents and left unaddressed.

With large amounts of data being converted into high-quality analytics, an organized, intuitive and integrated delivery mechanism is required to be in place for utilities to fully leverage the intrinsic advantages of the extracted information.

Modern software platforms are now being offered to organize and package analytics, while aiding in deployment of the mobile workforce and offering other integrated work management tools.

Cloud-based platforms offer stability and scalability, and enable utilities to create and manage a single source of location-based data across the entire organization. They also offer real-time access to actionable analytics to support business processes to any user, whether they're in the office or in the field.

Because field staff often work in remote areas, software platforms are now available that enable them to work offline and automatically update work records when connectivity is reestablished. The power of syncing tree data and work histories with organized, enterprise-level databases now affords management the opportunity to provide real-time snapshots of vegetation status and a historical baseline for planning future field work. Also, tight integration with existing management systems for accounting, engineering and operations supports closed-loop processes, ensuring data stays current so vegetation management teams can direct daily duties to maximize budget and infrastructure reliability.

A Look into the Future

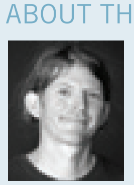
Across the industry, VM programs are faced with increased scrutiny related to risk exposure and operating expenses. Cycle, foot and visual patrol-based inspections are becoming increasingly difficult as operating budgets are under-funded, cut or significantly reduced over time. The traditional VM model requires new approaches as utilities accommodate additional infrastructure, alternative power sources and new customer bases.

Increasingly, autonomous robotic systems are being developed to track changes in vegetation health and growth rates, as well as changes after natural disasters for ongoing, real-time assessment, as opposed to the typical annual or periodic patrols.

Other trends in remote sensing applications point to an increasing variety of sensor types collecting more data in an even shorter period of time. This collection speed requires forward-thinking utilities and vendors to deliver solutions that can ingest the ever-increasing data load and promptly convert it to actionable information.

Continued research in remote sensing technology, sensor development, artificial intelligence, cloud-based applications, processing automations and interactive/immersive digital environments will drive the continued evolution of utility vegetation management long into the future.

ABOUT THE AUTHOR



Will Fellers is the Product Manager, Quantum Spatial Inc. Since 2006, Will has spearheaded the technical development of a comprehensive set of innovative products utilized across technical platforms at Quantum Spatial. He and his team are currently focused on state-of-the-art solutions for remote sensing applications using machine learning/artificial intelligence systems, advanced data analytics, high performance cluster computing, immersive 3-D environments and cloud-based data distribution models.

SECURITY SESSIONS

By Doug Houseman and Sean Morash

Models, Patrols, and Pads

In the future, all of the analytics, automated restoration, transactive energy and other changes to operations will rely on one key foundation: the underlying grid model and its accuracy.

Back in the 1960's, the grid model was a single line drawing that was done with a T-square on a drafting board. Transformers were typically denoted at the end of each lateral without regard to actual placement or connectivity to customers. After all: what more did the industry need? There were no sensors, no controls, and no generation on those circuits; phase imbalance was handled by moving a transformer from one set of connections on the feeder to another. The system was set up to build it and forget it. The model only had to be as accurate as the engineers, planners and field personnel needed.

Over the next 50 years, the industry made a large number of decisions regarding data location that did not fit in the grid model. Transformer to meter relationships went into the Customer Information System (CIS) for instance, information on assets ended up in asset management systems and so forth. The grid model was transferred into both the Geographic Information System (GIS) and the Outage Management System (OMS), and in many cases individual circuits were placed in the modeling tools like CYME and Synergy. Since there was little real-time operation, this worked well and each business area had direct control of the data they managed.

Fast-forward to the current decade and grid operations has (or will depending on where you are) changed drastically. Remote fault indicators, distributed generation, demand response and dozens of other technologies are impacting the grid. Instead of having little or no visibility beyond the substation, new meters, intelligent grid devices and distribution automation have provided lots of sensor data. The problem is that the data can be misleading if the grid connectivity, equipment location, customers served and other information in the model is wrong. Something as simple as the restoration from a car hitting a pole can change the grid configuration, especially if the pole that was hit had several services on it. Existing models tend to go out of date over time, and diligent upkeep can be time consuming and viewed as an operations and maintenance (O&M) expense to be avoided, but a pair of common modern technologies are making patrol life easier.

In the 1990's, patrolling a line was done with a clipboard and a good pair of boots. Typically the patrol was a 4 to 5 mile per day activity, with the notes being turned in weekly and manual update being done in a few days to a few months later. In some cases, the updates had to be routed to 2 or 3 departments to have data entered into the different systems.

Fast-forward to today and technology has offered advances that mean that patrols can cover 8 to 10 miles a day and data updates can be completed within 24 hours, and in some cases in near real time. Key technology comes in two forms: small all-terrain vehicles [ATV] (ala the John Deere Gator) and pad style computing devices [PAD] (e.g. iPad, Android Pads). The ATV provides mobility and the ability to carry additional instrumentation, cameras, water and other supplies. The PAD provides the ability to see what the various existing models show and allow rapid entry of changes to the models. Obviously, field collected data should be reviewed before being put into the master data bases, but key information can flow back to engineers and planners via text messages, or emails, allowing them to ask questions before the crew moves on too far.

For example, one circuit model in a recent patrol was shown in the grid model as being secondary – beyond the distribution transformer and was displayed as a transformer on a pole. When the patrol team arrived, it was clear that the model was incomplete. The secondary was actually primary and there were 3 pole transformers at that location.

Within 10 minutes, the patrol was able to send an email, mark with GPS the locations of the 7 poles on the lateral, and the locations of the 3 transformers. By the time they had the information in the PAD, one of the engineers who was emailed asked to have the team determine the transformer sizes and take photographs of the poles in the lateral. Another 5 minutes' worth of work was done and the inaccuracy in the model was fixed.

Prior to use of a PAD, the team had to have a laptop or carry drawings into the field to mark up. In both cases, the patrol team needed far more training in entering data. With modern PAD tools, the team member only has to touch the screen to indicate a location, or open a pull down menu. Determining accurate locations meant surveying equipment or separate GPS equipment. Now holding the PAD close to the pole or other equipment can give a GPS location automatically within a few seconds. Picture taking and review is easy. When a film based camera was used, bad pictures could only be determined after the film was developed. Now a quick look at the screen will provide an answer about is the photo showing what the engineer or planner back at the office will need to know.

A current project is looking at the first pilot set of circuits, and updating those circuits. The goal is an up-to-date grid model that can be used by the GIS, OMS, grid modeling tools, and other systems that need an accurate grid model.

Now reality has to set in: patrolling once every 5 to 10 years can help find major issues, but every storm, collision, or touch to the grid may change the model. EPRI and others are working on ways to automatically determine whether there have been changes to the grid. One method is to look at meter recorded momentaries, switching and capacitor bank transients, and other recordable changes in the voltages of the circuit.

But the ATV and PAD can cut the cost of patrols by as much as 50 percent, verification revisits by 70 percent and improve data accuracy and speed of entry significantly. While many of us worry every day about the next analytic, we all need to remember that the grid model is the base of most of our analysis.

Doug Houseman's Holiday Wish List

Holiday lists are a tradition in much of the world. In many cases children wish for items that are not actually available, hoping beyond hope that someone will create what they want. This article is in that vein of wish lists.

Too often when doing design work on 'future grids' the key equipment needed does not exist yet. Some of these items are in the lab, and some are math concepts, but they all lead to new equipment that improves reliability, resiliency and hosting capacity for DER.

We can start with some simple applications of power electronics and solid state equipment with two items that would greatly increase the ability of the grid to deal with phase imbalance and improve hosting capacity.

With the typical demographics on a distribution circuit and the typical first-come, first-serve policy in most states, phase imbalance rapidly becomes an issue. So two items help fix this:

1. Solid State Phase Balancer: a device that can take excess energy off of any 1 phase and transform it to match the energy on any other phase and inject the power into one or both of the other phases, allowing a physical balance of energy. There are a number of challenges with safety and operations that need to be dealt with, but this device allows continued imbalanced installation of DG beyond conventional hosting capacity.

2. Solid State Tap Changers that can work on each phase differently. In some cases the voltage on one phase may need to rise, while the other two need to decline (or other combinations). The solid state tap changer allows far more operations per day than any conventional tap changer and allows rapid adjustment to voltage based on the actual production and consumption on each phase of the circuit.

The next item actually exists and a few utilities are installing them, but most are not. That is 5, 10, and 20 MVA, modular substations that are double insulated like a typical pad mount residential transformer. The nice things about designing with modular substations is that they can: be kept in stock, quick to install or replace, much lower cost, and the criticality of a modular substation is much lower. Getting to N-1 on a 100 MW does not require 2 - 100 MW substations, but rather it can be 11 – 10MW substations, increasing reliability, while reducing costs by up to 70%.

Next on the wish list: low cost sectionalizers that can be used to replace fused cutouts on a 1 for 1 basis. This will allow faster, automated restoration to more customers. Ideally the sectionalizers can operate on single phases at a time, so that if the fault only effects 1 phase, the rest of the customers can be restored.

One of the real hassles in the industry is upgrading the voltage on an existing circuit. Take a circuit that started life as 9600 volts, today it might be nice to take it to 22KV. To do that is a long, slow process and involves a huge amount of labor. What the industry needs is a portable upgrade system that allows quick changes to voltage, with minimal interruption to all customers. I have no clue how to do this, or what the technology is, but I want one.

A simple request on my list is for small capacitor banks and highly intelligent controllers that can be given a set of parameters to operate within. The capacitor bank would be segmented so the controller could turn on or off a small piece at a time, giving a much smoother operating curve and letting to be used in far more situations.

Next is an item on my list to frustrate hackers, that is a set of communications and controls that would fail useful, rather than safe. Typical IT systems fail safe, turning everything off until the hack can be defeated. In the electric grid, failing safe in the IT sense, means the hacker wins. Instead the systems need to gracefully fail in such a fashion that the remote controls turn off, but the device still delivers power. This should work on all field devices from meters and interconnects to capacitor banks and relays.

While I love the Open Field Message Bus (OpenFMB) and I think it has huge play in the industry, I want the bigger brother of the OpenFMB, The Distributed Intelligence Node, with the ability to operate based on parameters without a connection to the central location. This node would be the ultimate autonomous controller, it will need a pile of software to go with it, like DER management, Power Quality Management and other useful software. Think of it as the ultimate Nintendo Console and a pile of games to play on it. Obviously it has to fail useful, and be highly secure.

Next is a gift for my engineering and design side, which is a complete rewrite and update of the Color Books, many of them are out of date and the utilities in many cases have written internal engineering and design standards because they are out of date. New color books will take a huge amount of work, but should accelerate the next generation of the grid faster than any other single gift anyone could give the industry. It would also make training planners and engineers much faster and easier. Ideally it would come with a 20 lifetime subscription to regular updates.

The next 3 items on my list are for making the best use of renewable resources. First, is process storage (e.g. hot water and ice) to fit into existing district heating and cooling systems. This would allow excess renewable generation to be quickly stored for use later in the day. Second, is Vertical Solar Air Heaters. These simple devices can take a large amount of heating load off the grid, and provide very low cost heating to most homes. They would be installed on the south wall of most homes and smaller buildings and provide up to 100% of the heat that a home needs. The concept has been around for 60 years, but no commercial manufacturer has made real product out of the units. Third and final in this set of presents, is solar panels that are backed with a water or glycol working fluid to absorb the waste heat. In the summer the system would reduce the temperature in the solar photovoltaic system – improving efficiency and in the winter it would provide useful heat. All year round, it would provide hot water for showers and other purposes.

Finally, I want to see nano-alloys out of the university lab and into production. A number of people have demonstrated lab scale (a few millimeters) conductors that have 2 to 4 times the ability to move power as conventional conductor. Nano-copper would easily replace paper wrapped leads in tight underground situations. Being able to move far more power in existing underground ducts would help with the next generation of city power networks.

There are dozens of other presents on my Holiday wish list, from analytics to a single Grid Management System to replace DMS, ADMS, OMS and all the other MSes that the distribution system operators are now contemplating – sort of an ERP for grid control. And more and more and more and...

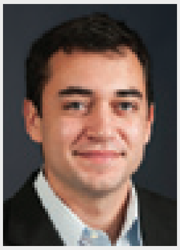
So, I hope Santa has room in his bag for some of my wish list. I want to see a highly effective grid moving forward, and all of these items will help.

I hope someone will read my list and take it as inspiration – creating not just what I wish for, but something much more useful.

ABOUT THE AUTHOR

Doug Houseman
As the Vice President of Innovation and Technology at EnerNex, Doug works with clients all over North America and Australia on issues related to smart grid/metering/ homes and with regulators, utilities and vendors to help move the industry to the next generation grid, and the next generation of customer relationship.

Doug has more than 30 years of extensive experience in the energy and utility industry and has been involved in projects in more than 30 countries. As a leader in grid modernization thinking, Doug was asked to author significant portions of the IEEE's GridVision 2050 and to revise CEATI's Distribution Utility Technology Roadmap. He is a member of the GridWise Architecture Council (GWAC) where he had a hand in both the Smart Grid Interoperability Maturity Model and Transactive Energy. Doug was named part of the World Generation Class of 2007, one of 30 people in the global utility and energy industry so named. He was the lead investigator on one of the largest studies on the future of distribution companies and in the last five years, has worked with more than 100 utilities and manufacturers, 50 governments, and five international agencies/NGOs.



Sean Morash
As a consultant with the EnerNex Smart Grid Engineering team, Sean produces solutions through research based on a working knowledge of Smart Grid related applications, including communication technologies and protocols, advanced sensing and control, renewable energy, electrical, mechanical and information systems integration, enterprise information architecture, cyber security, information modeling, and related disciplines and methodologies. He specializes in the simplification of complex modern grid themes and systems.

Guest Editorial 1

The More Things Change, the More They Stay the Same!

Reflection on Field Mobility in Utilities over the past 20 years

By Mary Brittain-White

Socrates in the 5th Century BC commented that children had lost respect for their elders and were generally playing up, a great example of how the passage of time changes very little. So how has twenty years changed the landscape in Utilities with their use of Field Service Automation?

The answer is disappointing, the key challenges essentially remain as they always have been even though the tools have been changed by advancing technology. Most of IT would now be howling for my blood, everything they yell has been radically improved and certainly zillions have been spent on achieving this outcome.

So to substantiate my position perhaps we first need to agree on what are the key challenges for field mobility? My assertion is that the two core challenges are still yet to be fully conquered:

Field Technician Acceptance

We commissioned a University of Technology[1] study in 2016 on the key heuristics (usability principles) required in mobile design. By observation of various applications live in the field they established eight key design principles, by example the tech needing to understand what his work and data that he collects meant within the whole process. However, other highlighted requirements show that the basics of the field solution being "fit for purpose" are still rarely achieved: IT departments love to roll out a "one size fits all" strategy resulting in technicians standing in direct sunlight with iPad screens they cannot see, HTML5 based programs that work poorly when not in coverage and a workflow imposed on them that suits back-office operations and not a holistic field work process are all common issues.

Additionally, literacy issues with field technicians are rarely conceded in design: to do this would require consistency in icon usage and navigation so that rote learning is achievable, alternatives offered to replace long written descriptives (e.g. unlimited photos, videos, voice annotation) need to be supported, and workflows thought through from reducing technician input (e.g. automated GPS and time stamping) rather than seeing technicians as in-field administration workers.

What has been achieved? Attaching asset history so that the field team understands the previous maintenance activity and the attachment of GIS and LIDAR extracts to give schematic information to field teams allows field crews to work in full knowledge and make better decisions. Field devices have also evolved markedly, from luggables to truly mobile, from shockingly expensive to cheap, from offline to mobile enabled.

Management of Field Activity

No doubt the advent of 3G/4G devices sending back work-order updates is a core achievement of the period. Supervisors and management can now see in near-real time the progress that crews have made, this is in contrast to twenty years ago when the status quo was radio or phone updates on emergency jobs and next day at best for general maintenance work. So transparency of field activity can now be achieved.

However, the IT myth of this period is optimised scheduling: the principle is that computers, not schedulers, can best organise work and reduce drive time, conflicts on equipment usage and skill set requirements. The IT capability to deliver optimised scheduling is real, but its practical and successful application to the field is rare and its cost to Utilities has been enormous. The emperor with no clothes is that optimisation is often turned off as Utilities revert to local knowledge to manage their scheduling work boards.

Why does this happen?

Guest Editorial [1]

The More Things Change, the More They Stay the Same!

The fundamental for optimisation to work is twofold:

1. **Quality data**: does the Utility have reliable data for how long a particular job type takes? Availability of technicians? Skills set updates and equipment availability? Without accurate information the optimisation result is worse than wrong – it has the authority that it is right when it is not.
2. **Constant fine tuning**: as the business changes, are the parameters on which the optimisation is based managed to reflect those business changes? This is a business analyst role which reflects data analysis of field performance and changing company priorities.

…but these two proficiencies are rarely in place, meaning that shortly after implementation the optimisation starts steering off course and by the mid-term its results are not respected internally. Millions of dollars have been spent, the internal effort has been enormous so no one wants to declare the project failure, they just move on.

There are exceptions of course: utilities that focus on data quality and the fine tuning. However, the stand out sector for success is cable. Why? Their number of job types are limited, single men rather than crews predominate, parts requirements and asset management minor in comparison to a traditional gas, electricity or water environment. So we have a solid example of technology working but need to find a newer delivery model to allow similar success in the traditional utility space.

So what for the next twenty years?

The move to out-sourcing of field crews, adding a separation layer between work preparation and in-field delivery and quality management will add complexity to the above issues rather than simplicity. However, I believe a change of attitude to IT solutions is occurring – a shift back to a pragmatic valuation of outcomes and a need for smaller steps with demonstrable advances is gaining traction. With such a trend the need is to seek solutions that are best of breed rather than IT logos or compliance to standardisation across the corporation – if we put the field worker as central to how we implement innovation then we can achieve real returns.

It is just a change of priority.

1 Reference to UTS Heuristics Study

ABOUT THE AUTHOR

After 20 years in the wireless data industry, of which 16 years are with Retriever, **Mary Brittain-White** has established herself as a thought leader in the area of wireless field automation. Prior to founding Retriever, she worked for a Silicon Valley based Motorola subsidiary, RadioMail, which pioneered wireless email. From University, she joined IBM and over a 14 year career there held Sales and Marketing executive management roles. She has a Bachelor of Economics from Sydney University and a post graduate Executive Development program from Melbourne University.

Guest Editorial 2

Transformer Risk and Reliability

Well-planned PM Programs Can Double Transformer Life

By Alan M. Ross

Transformers are the heart of an electrical system. As such, any discussion on reliability must start with the transformer. Yet, while robust reliability standards have been developed by IEEE, CIGRE, IEC, and ASTM for most productive equipment within their respective areas of expertise, transformer reliability is not an area of focus for most modern facilities. The reason is that the risks associated with potential transformer failures have been overlooked. Unfortunately these risks are now threating the productive capacity of plants and facilities to avoid unplanned outages.

Transformer Risk and Reliability

The Risk/Reliability equation can be expressed as follows:

$$\text{Risk of Failure} = \frac{\text{Productivity x Consequences}}{\text{Detectability}}$$

The probability of transformer failure has been low for decades. This is rapidly changing as aging transformers are being replaced with newer units, assuming this action will eliminate the probability of a failure. This reasoning however is no longer valid because the newer units now have an increased level of risk. One reason has been past reliance on a 'bathtub curve' that projected higher failures at start-up for one year, then a leveling out of risk. However, with newer transformers, the initial risk has now been increased from one to three years. Simply replacing old units with newer ones does not eliminate the probability of failure. The older units were built to account for potential errors. Today's computer modeling allows transformers to be built to exacting and precise standards; they are no longer 'overbuilt.' In addition, there is now greater price competition with more transformer OEMs in the market, which has also led to greater cost controls.

Probability of Failure

According to insurance industry reports, failures of aging transformers have increased from less than two percent over the past decade to now three percent. While this isn't much of an increase, it is not so much the probability of failure that makes the difference. Rather, it is the consequences from those failures that are dramatically increasing. According to Figure 1—Consequences From Transformer Failures—the best method of determining consequences is to monetize the potential impact, an extremely difficult task. In our experience, we have seen consequences from minor irritations to complete shutdowns costing multiple millions of dollars.

Consequence	Very High	High	Moderate	Low
Plant/Line Downtime	Major	Minor	None	None
OSHA/EPA Event	Yes	No	No	No
Business Interruption Insurance	Yes	No	No	No
Replacement Lead Time	>90 Days	60-90 Days	30-60 Days	<30 Days

Transformer Reliability Planning

Clear standards exist for the chemical testing of transformer fluids. However, a great deal of discretion is applied to which transformers are tested and when. Coupled with advances in testing technologies and monitoring capabilities, there is a disparity of approaches when seeking to arrive at the best reliability plan for transformer fleets. Determining the consequences that may result from a failure is a good first step. Suggested steps in designing a reliability plan are outlined in Figure 2. While a Basic plan might suffice for a small pad-mount transformer, a more advanced plan would be warranted for a critical unit. Basic plans lead to the highest potential for unplanned outages. Whereas Assurance plans – while never guaranteeing that an outage will not occur – are by far the safest plans for critical units.

BASIC	AWARENESS	PREVENTIVE	ASSURANCE
Highest rate unplanned outages.	Reduced Rate of outages	Minimal exposure to unplanned outages.	Avoidance of outages
Short-term gain Long-term negative Impact	Improved awareness of unit condition	Limited prema-ture agin of units	In control of uptime reliability
		Reduced capital need	Life extension of asset beyond industry norm.
Expensive reactive repairs.	Still conducting Expensive repairs		Minimal capital need.

Paper, Oil and Detectability

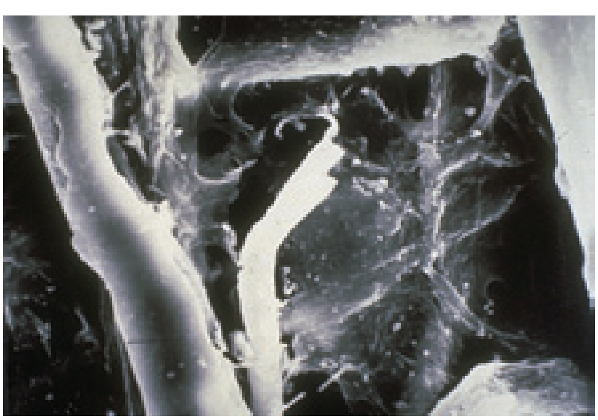
Kraft paper is the insulating material used to separate the copper windings in transformers. This provides mechanical and dielectric strength and dielectric spacing. The life of the transformer is based on the life of the paper. As paper degrades, the reliability of the unit degrades proportionately. It is essential to understand that the degradation of the paper is irreversible.

Dielectric fluid (mostly mineral oil) acts as a coolant, provides additional dielectric strength, protects the paper and plays a lead role in detecting problems in the transformer. The most fundamental action in transformer testing is a diagnostic testing of the fluid, regardless of its composition. Chemical testing is the accepted industry standard for detecting the reliability of a transformer.

Oil plus a catalyst like paper, copper and iron – coupled with an accelerator like heat and moisture – creates oxidation. The oxidation byproducts are numerous:

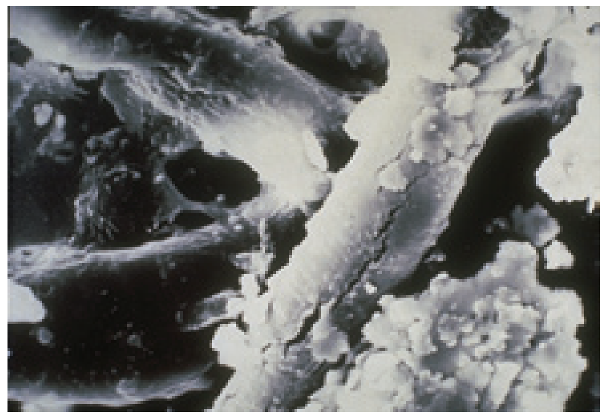
- Alcohols
- Peroxides
- Ketones Aldehydes
- Metallic Soaps
- Epoxies

The singlemost byproduct of oxidation that degrades paper significantly is acid. The following photos (in 750x magnification) show unacceptable levels of acids in paper.

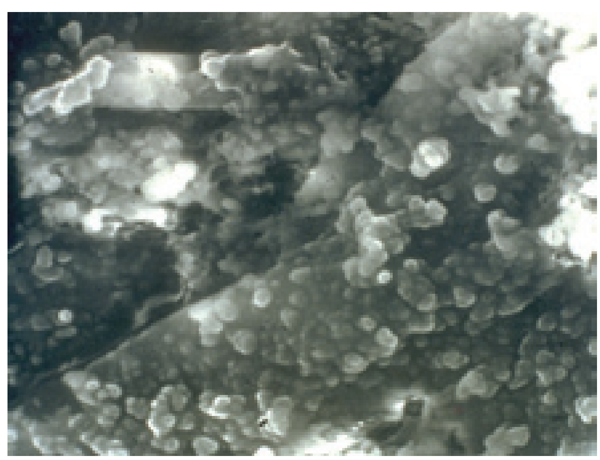


An acid level of 0.5 is considered the beginning of a Questionable level. Given that paper degradation cannot be reversed, a Questionable level of acid is the first sign that maintenance is required.

An acid level of 0.10 is considered to be the beginning of an Unacceptable result. Typical signs of this degradation level are the buildup of the acid along the fiber strand and the beginning of splitting within the strand is shown.



An acid level of 0.15 shows even more paper degradation and acid build up. Fiber strands are breaking and acids continue to accumulate.



At an acid level of 0.30, the paper begins to look more like porridge than paper. Much of the dielectric strength is lost, and the life of this paper does not bode well for the reliability of the transformer.

Additional chemical testing for greater diagnostics are:

- Liquid screen
- Inhibitor content power factor
- Karl Fischer (moisture)
- Gas in oil (DGA), Metals in oil
- Furan
- PCBs (when appropriate)

Field Inspection

The value of a simple field inspection is often overlooked when sampling transformer fluids. A good visual inspection should look for and document the following:

- Area accessibility
- Paint condition
- Gaskets
- Bushings

Also the readings and accuracy of the following gauges should be checked:

- Level
- Temperature
- Pressure/Vacuum

Infrared and Chemical Testing Are Best Done Together

While IR testing is basically standard for electrical systems, the annual IR test is usually conducted for the entire facility, and the test of the transformer is seldom correlated to the time a fluid sample is pulled for the chemical analysis. Conducting a thorough IR scan at the time of fluid sampling provides better information for the IR and better information for oil analysis. This allows the engineering team to better identify the cause of a hotspot picked up on the IR report. Another benefit of coordinating IR with fluid sampling is that the resulting data can be integrated with the chemical data. Should there be an issue, this avoids the need to search for two sets of data that do not correlate because of the timing when each test was conducted.

Infrared scanning should focus on detecting…

- Temperature under 65°C/55°C
- Heat dissipation from top of the transformer tank/radiator to bottom of the transformer tank/radiator
- Low oil level
- Temperature difference between two similar bushings
- Hotspots showing on tank, LTC component, throat connections, or bushings

Preventive & Predictive Maintenance

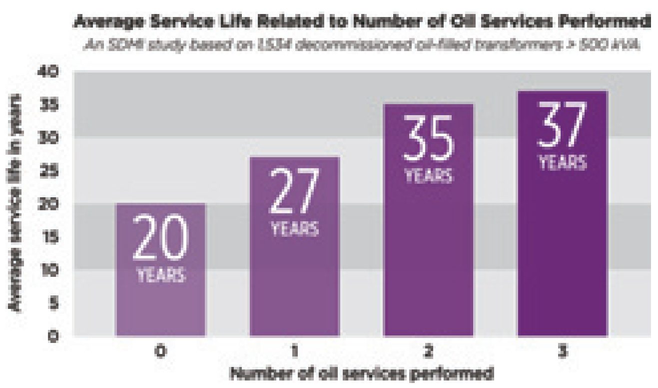
One of the most disturbing trends in determining reliability is a tendency to ignore any sort of maintenance on transformers other than reactive maintenance. Considering the irreversible nature of paper degradation, it would seem logical to use diagnostic testing to determine the maintenance standards you will follow. In far too many cases – when conducting a Root Cause Analysis of a failed unit – the condition of the equipment prior to the failure was clearly documented as Questionable to Unacceptable, two ratings we use based on the specifics of the diagnostic tests. As shown in the acid photos, an acid level of between 0.5 and 0.10 is Questionable, and a level of more than 0.10 is Unacceptable.

In any reliability program, when equipment reaches these levels, the CMMS launches the process of addressing the issue in time to avoid a failure. One of the difficulties in doing so is because most CMMS and EAM programs do not have a built-in capability for transformers. As a result it is recommended that a more comprehensive data management program be installed to include transformer testing.

A good PM or PdM program includes:

- Vacuum Processing / Degassing
- Re-inhibiting
- Moisture Reduction
- Hot Oil Cleaning
- LTC Inspection and Repair
- Re-gasketing
- Refurbishing
- Full Electrical Testing

The impact of such testing services on transformer life is shown in Figure 7, Average Service Life Related to Number of Oil Services Performed. This study was based on more than 1,500 decommissioned units.



For the units in the study where no PM or PdM service was performed, the units survived for just under 20 years. This is what the insurance industry and many OEMs have predicted. But with just the performance of one service, the life was extended to more than 27 years. Two service procedures resulted in a life extension to just short of 35 years, and three services extended the life of the unit even further. It is without question that the life of a transformer can be doubled by properly maintaining the oil, removing moisture from the paper, and doing basic connection or bushing repairs. To summarize, a well-maintained unit is at a reduced level of risk and is much more likely to survive external faults than a poorly maintained one.

Fault Gas Monitoring

Transformer monitoring is a rapidly growing field. The market for DGA monitors is estimated to be more than $755 million by 2020. This includes expansion from predominantly utility and generation monitoring into wider and broader applications throughout the power grid. It is now common to purchase DGA monitors along with the purchase of a new transformer. Adding monitors to critical in-service transformers has become a significant component of transformer maintenance and reliability programs.

DGA monitor manufacturers use many different technologies for the purpose of dissolved gas detection in active monitoring. The largest manufacturers predominantly use gas chromatography (GC), photo-acoustic spectroscopy (PAS), and solid state (SS), thermal conductivity detector (TCD), or selective membrane (SM) based sensors. Other emerging DGA monitoring technologies include non-dispersive infrared (NDIR) and carbon nanotube (CNT).

SDMyers conducted an 18-month study that included all major OEM monitors that account for 95% of monitors in service. The study included monitor responses to fault simulations. Our findings are summarized as follows:

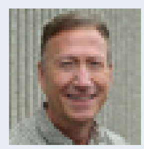
- The monitors worked. While there was some differences in lead and lag times for gas detection, overall DGA monitoring works well.
- There can be false positives. This requires diligence in understanding which data to avoid. However, when false positives are simply and routinely ignored, the level of risk to the unit is increased.
- Data management for monitor data can create data chaos. Correspondingly, most monitoring data is not integrated into the chemical, mechanical or electrical testing data.
- Hydrogen was present in every simulated fault condition, making the monitor an effective low-cost 'check engine light' of sorts. Running a chemical DGA after an alarm can then determine the precise nature of the events. Combining the DGA with the hydrogen monitor is suitable approach to transformer monitoring. There are certain transformer applications where multiple gas monitoring would be recommended, based on requirements for a broad range of gassing conditions and for transformers with a very high consequence from failure.

Summing Up

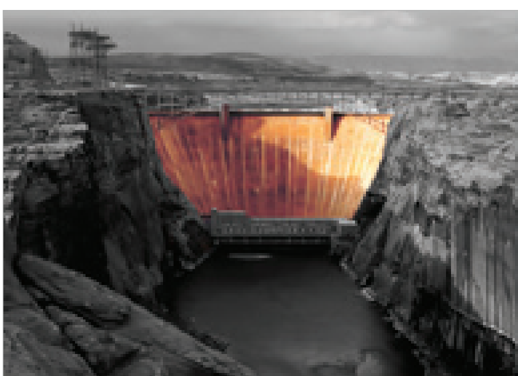
Without a well-planned oil service maintenance program, the risk from an unplanned fault either up or down line can result in substantial costs in both time and money. Yet with an astute, planned maintenance program, it is possible to nearly double the service life of the transformer. We would do well to remember the Risk/Reliability equation:

$$\textbf{Risk of Failure} = \frac{\textbf{Productivity x Consequences}}{\textbf{Detectability}}$$

ABOUT THE AUTHOR



Alan Ross of SDMyers is responsible for developing and executing long-term reliability strategies and next-generation leadership for all domestic and international operating units. He often presents at industry conferences and has authored two books, *Unconditional Excellence* and *Beyond World Class*. He completed his undergraduate degree in Mechanical Engineering at Georgia Institute of Technology and an MBA in Marketing from Georgia State University, graduating Magna Cum Laude. Alan is a Certified Reliability Leader, SMEP designee to the DOE's Strategic Transformer Reserve task force and a member of the IEEE Reliability Society.



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