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Electric Energy T&D MAGAZINE

NOVEMBER-DECEMBER 2015 Issue 6 • Volume 19

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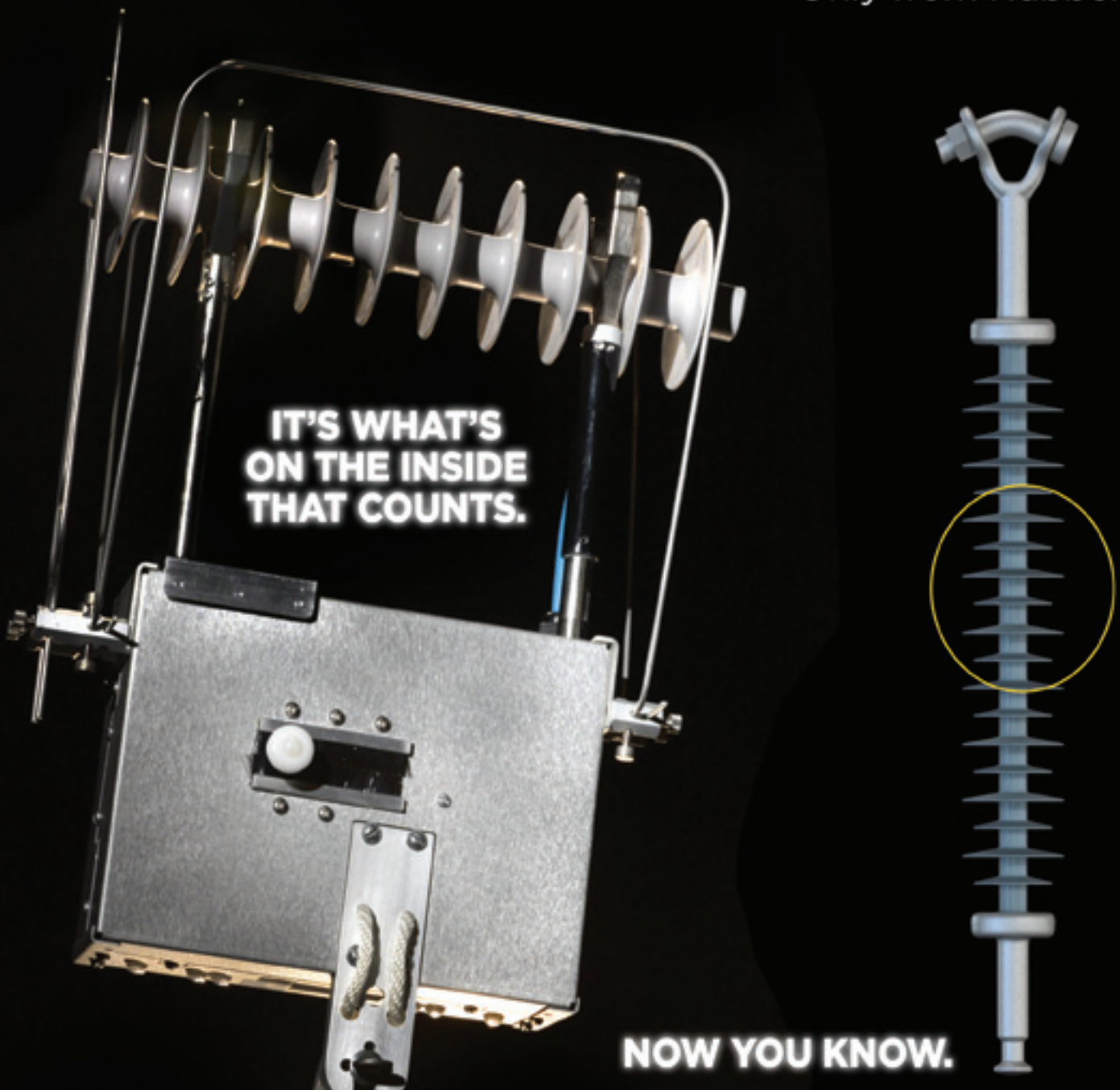

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Electric Energy Magazine is published 6 times a year by: Jaguar Media Inc.
834 Montée Masson
Terrebonne, QC Canada J6W 2C6
Tel.: 888.332.3749 • Fax: 888.243.4562
E-mail: jaguar@jaguar-media.com
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Post Publication mail agreement #40010982
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POWERPOINTS

Editor-in-Chief
TERRY WILDMAN

No Right Answers

In the last issue I mentioned that Canada was in the middle of an election at the federal level. I'm happy to tell you that Canadians from coast to coast to coast turned out to vote in large numbers. A new government has been elected with a majority of seats in the house. Finally. We have a new Prime Minister who is armed with a love of country and a commitment to all Canadians to do the right things. He will be stepping into the ring with the desire to fight to reduce our dependence on fossil fuels and kick-start Canada's rightful position as one of the countries most dedicated to solving the on-going phenomenon called climate change.

Extreme and record-breaking storms, floods, heat waves, droughts, and related wildfires worldwide are undeniably and dramatically demonstrating the need for meaningful reductions in the generation of the carbon emissions that are augmenting these extremes. But the long-range outlook for achieving the reductions needed to avoid the climate catastrophe does not look promising – as long as carbon-based fuels remain the chief movers of commerce and of transportation in particular. Things won't change as long as this pattern is being replicated throughout the fast-developing world.

Abundant stores of natural gas in both the U.S. and China have now been made accessible by breakthroughs in seismic imaging, horizontal drilling, and hydraulic fracturing. This has opened the opportunity to replace much dirtier coal as a major fuel for the generation of energy. The proviso is that any type of drilling for gas must be carefully regulated with regard to water contamination, carbon dioxide and methane emissions, and earthquake. Yet natural gas should be considered an *interim* solution only, since it is still a fossil fuel that emits about half as much greenhouse gas (GHG) as the burning of coal. A sustained glut of inexpensive natural gas could actually short circuit the prospects for new investments in wind and solar power. This would undermine the large-scale development of truly clean energy as well as efforts toward energy efficiency and conservation.

In its biennial *Energy Technology Perspectives* report released in July 2012, The International Energy Agency (IEA) described three possible, dramatically different trajectories for climate change. The gravest of these is a business-as-usual attitude in which the world will experience a temperature rise of at least six degrees Celsius above pre-industrial levels. Unfortunately this is our current trajectory. A second possible scenario would reflect some of the current pledges of governments for more robust climate policies by which temperatures would still increase by four degrees Celsius. Thirdly, most scientists agree that, to avoid the worst effects of climate change, it will be necessary to limit the temperature rise to two degrees Celsius by no later than 2017.

Paradoxically, there is currently a powerful drive in the Western Hemisphere, notably in the U.S., and Brazil to boost the output of fossil fuels. Under its last Federal government Canada was also looking to increase output from the tar sands. The process releases staggering amounts of carbon and has destroyed more than 300,000 ha of boreal forest – which is a vital sink for carbon pollution. Fortunately Canada's newly-elected prime minister will be putting the brakes on the amount of oil being mined from the bitumen going forward, preferring instead to develop renewable sources of energy. To meet retrieval of fossil fuels, new high-tech methods have been introduced. These new methods are being used to extract previously identified reservoirs that were long considered unreachable because they were too far offshore, too deep in the ground, or too solidly encased in rock to be extracted profitably.

This brings me to another thought. I can't remember the last time the use of corn for fuel crossed my mind but the practice still goes on with ever questionable results for the climate and negative impacts on the poorer people across the globe. There is no such thing as a 'free market' in energy. In the U.S., fossil fuels, together with corn ethanol, that currently get 88 percent of monies set aside have benefited from years of subsidies and supporting infrastructure.

They remain heavily subsidized to this day. The oil industry, in particular receives generous tax breaks at every stage of the processes of exploration and extraction. The fact of the matter is that the industry would be highly profitable even without tax incentives. By way of example, U.S. federal subsidies for energy (2002-2008) looked like this:

- Fossil fuels – USD72.5 billion including, USD70.2 billion for traditional fossil fuels and USD 2.3 billion for carbon capture and storage.
- Renewables – USD29.0 billion including, USD16.8 billion for corn ethanol and USD12.2 billion for traditional renewables.

It should be noted that the subsidy figures for corn ethanol ignore the negative effects not only on world hunger but also on climate change that result from the massive conversion of forests for the production of the gas as well as the amount of water needed to grow this thirsty, fertilizer-intensive crop.

According to Lester Brown of the Earth Policy Institute worldwide direct fossil fuel subsidies in 2010 amounted to roughly USD500 billion, one-quarter of this amount supporting production and the remainder supporting consumption. Humanity is thereby spending nearly USD1.4 billion per day to further destabilize the climate. Comparatively, renewable energy received just USD66 billion, one-third of which was spent on biofuels.

Brown has cautioned that global demands on the earth's natural systems are exceeding their sustainable regenerative capacity by an estimated 30 percent. The need to develop a realistic, working relationship between our economy and the natural environment is vital particularly when the world is expected to add another three billion people by the middle of the twenty-first century.

A stark example of this mismatch can be seen in the conflict between our expanding use of crops for fuel and the needs of humanity for food. Edible crops such as corn, cassava, rapeseed, and sugarcane are raised in the less developed countries explicitly for use as fuel. China, Europe, India, Indonesia, and Thailand are striving to meet strict biofuel targets. We must not forget this is only one of the reasons for the surge in prices of food that has recently proven so devastating in impoverished nations. Other factors include the relentless growth of world population, extreme weather events like floods and drought, a jump in meat and dairy consumption associated with rising affluence, and heavy market speculation in commodities, in particular grain and petroleum. But aggravating all of these factors is the production of crops for energy, which almost invariably competes with the production of food.[1]

The world's leading exporter of grain is by far the U.S. And because the conversion of grain into ethanol has been mandated by the federal government in its Renewable Fuel Standard, an investment frenzy has developed around biofuels. The net result was a boost in grain prices well above historic levels – in a world that no longer has excess cropland to play with. It has also resulted in extreme hunger and hardship in the developing world. People in low-income, grain importing countries are taking a real beating.

Lester Brown has noted this irony:

> The grain required to fill an SUV's 25-gallon (U.S.) tank with ethanol just once will feed one person for a whole year… [There is] an emerging competition between the owners of the world's 910 million automobiles and the 2 billion poorest people… The average income of the world's auto owners is roughly $30,000 a year. The poorest people can earn on average less than $2,000 per year. The market says: "Let's fuel cars."[2]

By July 2012, the hottest month in the U.S. since record keeping began in 1895, the devastating effects of severe heat waves and drought on harvest had made it evident that it is neither sensible nor safe to build an energy sector that is even partially based on water- and weather-dependent crops. With the nation's worst drought in over fifty years, much of the corn crop was lost forcing government predictions on the corn yield to the lowest point since 1995.

This is where I take one side of a fork in the road and talk about some financial heavyweights and what their take is on corn ethanol and biofuels in general. Although he professes great concern about climate change, the Gates Foundation had at least USD1.2 billion invested in just two oil giants – BP and ExxonMobil as of the end of 2013.

Gates's approach to the climate crisis is to develop a silver-bullet techno-fix in the future, without stopping to consider viable – if economically challenging – responses to the here and now. He is calling on governments to massively increase spending on R&D with the view to uncover 'energy miracles.' By miracles he means nuclear reactors the types of which have yet to be invented. He also wants to see machines that can suck the carbon out of the atmosphere. Mr. Gates has already sunk some of his own money into various schemes to block the sun and his name is listed on several hurricane suppression patents.[3]

Entrepreneur Richard Branson's success is built partly on the fact that he controls all major operating aspects of each of his businesses. He asked himself why pay the oil giants to power his airplanes and trains when his labs could invent its own transport fuel. If it worked, the gambit would turn him into an environmental hero. Virgin Fuels was born and later became the Virgin Green Fund.

Branson launched into his new enterprise by investing in various agrofuel businesses including a very large bet of roughly $130 million on corn ethanol. Virgin also attached its name to several biofuel pilot projects including one that could derive jet fuel from eucalyptus trees and another from fermented gas waste. In spite of his ambition, he readily admits that the miracle green fuel he was hoping for hasn't been invented yet. The other side of the coin is that thanks to the influx of fracked oil and gas, biofuels are taking a back seat. Another thorn in Branson's side is that it's all but impossible to sell the airline industry as being green.

Out of sight, out of mind it may be. What started as an encouraging idea seems to be quietly hamstringing many parts of the world. This should be very worrying to all and sundry who wish to one day get on top of climate change.

[1] Roxanne Warren, "A Market to Match Ecological Truths," *Rail and the City.* MIT Press (2014):
[2] Ibid
[3] Naomi Klein, "No Messiahs," *This Changes Everything: Capitalism vs The Climate.*Toronto, Knopf Canada (2014):

ACCIONA to build an electric power grid in northwest Mexico for 90 million dollars

The Federal Electricity Commission awarded the project to transmit the energy generated in the Empalme II plant to the States of Sonora and Sinaloa

November, 2015

The Mexican Federal Electricity Commission (CFE) has selected ACCIONA Infraestructuras México, through its Industrial Division, to design and construct a 117-kilometer-long power grid to transmit the energy generated in the combined cycle Empalme II plant to the States of Sonora and Sinaloa.

The project, valued at 90 million US dollars (around 85 million euros) is the first construction of a power grid in Mexico awarded to ACCIONA by the CFE and it will be designed and built by companies of the ACCIONA Instalaciones México Group: ACCIONA Ingeniería and ACCIONA Industrial.

The grid will consist of 117 kilometers of high-voltage power lines and four substations, and it is expected to enter service towards the end of 2017.

ACCIONA Infraestructuras México Director-General Guillermo Jiménez points out that this project will help to cover the growing demand for electricity in the northwest of the country: "We are proud that our company has been entrusted to be part of this new phase in the development the power sector in Mexico, spearheaded by the country's Energy Reforms."

The project was awarded to ACCIONA Infraestructuras México in a public tender that attracted bids from eight national and international firms.

Mexico is one of ACCIONA's principal strategic markets. The Spanish group opened its first office in Mexico in 1978 with its Infrastructure Division. Today, ACCIONA has major projects in all its business areas: Infrastructure (Construction, Water, Industrial and Services), Renewable Energy, and other businesses such as property development (through ACCIONA Parque Reforma).

After more than 30 years, ACCIONA has consolidated its presence and deep knowledge of the local operating conditions in the country. Its commitment is evident in its long-term investments, in its talented Mexican team and in its commitment to sustainability and innovation as the drivers of its day-to-day operations.

ACCIONA México is currently developing the Phase 5 power plant in the state of Baja California Sur; the Jala-Puerto Vallarta road; the first General Hospital of the Mexican Social Security Institute (IMSS) in Nogales and the Atotonilco wastewater treatment plant, one of the biggest water treatment projects in the world. ACCIONA Servicios is also providing services to the General Motors plant in San Luis Potosí.

Trauschke to succeed Delaney as Chairman of OGE Energy Corp.

November, 2015

OGE Energy Corp. (NYSE: OGE) announced that Sean Trauschke, President and CEO, has been named Chairman of the Board and will succeed Peter Delaney. Delaney will continue to serve on the Board of Directors until the end of the first quarter of 2016.

Delaney, formerly President and CEO of OGE Energy, announced his plans to retire from the Company at the Company's annual meeting in May. In keeping with those plans, he retired as CEO in June 2015 and Trauschke was named to replace him. Delaney then became interim CEO of Enable Midstream Partners, a midstream natural gas business in which OGE Energy is a partner, while remaining Chairman of the Board of OGE Energy Corp. Delaney's retirement as Chairman was the next planned step in the succession plan.

"First of all I am honored to be named Chairman of the Board of such a fine company," said Trauschke. "To lead a 113 year old, Oklahoma-based company is a privilege. Secondly, it is even more of an honor to have the backing and support of Pete Delaney. He has been an outstanding leader of our company and in the community."

Delaney said, "My management efforts at this time need to be focused on an effective transition of leadership by year's end to Enable's new CEO, Rod Sailor, so this is a good time to complete the transfer of executive duties at OGE to Sean. I am confident in Sean's ability to lead OGE Energy forward in the years to come."

Trauschke joined OGE Energy in 2009 as vice president and CFO. He was elevated to president of OG&E in July, 2013, and to president of OGE Energy Corp in May, 2015. Prior to joining OGE Energy, he served in various leadership positions at Duke Energy. He holds a bachelor's degree from the University of North Carolina at Charlotte and a master's degree in business administration from the University of South Carolina.

Delaney joined the Company in 2002 as Executive Vice President-Finance and Strategic Planning and as CEO of Enogex Inc., the company's natural gas subsidiary, following more than fifteen years in the investment banking industry. He was appointed Executive Vice President and COO of OGE Energy Corp. in 2004, and appointed President and COO and elected to the company's Board of Directors in January, 2007. In September, 2007 Delaney was named Chairman and CEO of OGE Energy Corp.

Ontario: City Greater Sudbury Recognized for Initiatives to saveONenergy

November, 2015

Greater Sudbury Mayor Brian Bigger accepted a cheque on behalf of Council for $239,836.52 in incentive rebates, upon the successful completion of 30 energy conservation projects under the Independent Electricity System Operator (IESO) saveONenergy program.

"I would like to thank Greater Sudbury Hydro and the IESO saveONenergy program for supporting the City of Greater Sudbury in our efforts to lessen our environmental footprint," said Greater Sudbury Mayor Brian Bigger. "We look forward to finding additional ways to reduce costs associated with energy consumption for a sustainable future and a healthy community."

The IESO saveONenergy program is facilitated by the Greater Sudbury Hydro EnergySavers team. Under the most recent Ontario Conservation Framework, the City of Greater Sudbury successfully completed 30 energy conservation projects, including lighting upgrades, more than 3,000 streetlight conversions, and equipment retrofits at several municipal facilities. In addition to the incentive cheque, these projects amount to approximately $270,000 a year in energy savings.

"We've been working very closely with Sajeev Shivshankaran, the City's Manager of Energy Initiatives," said Jill Kirwan, Energy Conservation Coordinator with Greater Sudbury Hydro. "He, and we, are committed to finding the best opportunities for the City to save energy as well as to recoup some of their investments on capital improvements through the incentive programs."

Enbridge Acquires 103-Megawatt West Virginia Wind Project

November, 2015

Enbridge Inc. (TSX:ENB)(NYSE:ENB) announced the acquisition of a 100 percent interest in the 103-megawatt (MW) New Creek Wind Project, from EverPower Wind Holdings, LLC. Enbridge's total investment is approximately US$0.2 billion.

Located in Grant County, West Virginia, New Creek Wind will comprise 49 Gamesa G97/G90 turbines and is targeted to be in service in December 2016. The project was developed by EverPower Wind Holdings LLC., an independent U.S. renewable energy developer.

"With strong fundamentals and commercial underpinnings, the New Creek Wind Project is a strong fit within our low-risk value proposition, and advances a key corporate priority of growing our renewable generation platform," said Vern Yu, Senior Vice President, Corporate Planning and Chief Development Officer, Enbridge Inc. "We welcome the relationship with EverPower, a safe and community-focused developer, owner and operator of U.S. wind projects."

The project is backed by renewable energy credit (REC) sales and off take agreements with fixed pricing through mid-and-long-term contracts.

New Creek will be constructed under a fixed-price engineering, procurement and construction (EPC) agreement with White Construction Inc. Gamesa will provide turbine operations and maintenance (O&M) services under a five-year fixed price contract, following which Enbridge will operate.

Including this acquisition, Enbridge has invested approximately CAD $5 billion in renewable power generation and transmission since 2002. Enterprise-wide, the Company now has interests in nearly 2,000 MW of net renewable generating capacity operating, secured or under construction.

New Creek Wind Project At-A-Glance

- Location: Grant County, West Virginia
- Installed Capacity: 103 MW
- Turbine Technology: 49 Gamesa G97/G90
- Developer: EverPower Wind Holdings, LLC

Merger of Enersource, Horizon Utilities, PowerStream; Acquisition of Hydro One Brampton Approved by All Shareholders

November, 2015

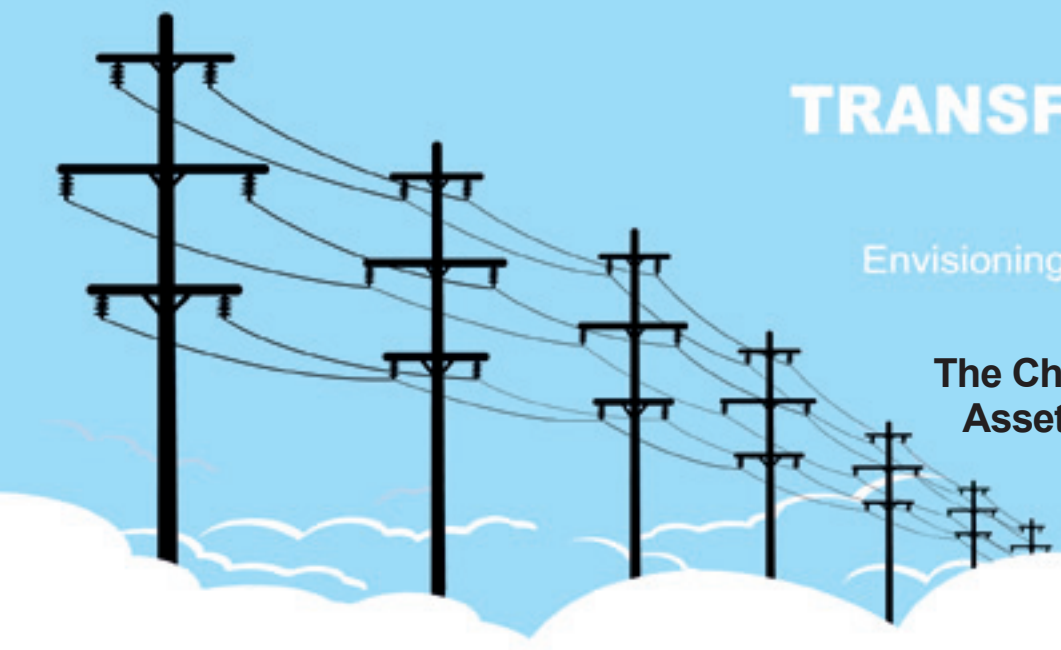
A proposal to merge municipal electricity utilities Enersource, Horizon Utilities and PowerStream and jointly acquire Hydro One Brampton has now received approval from all shareholders.

The City of Markham became the final shareholder to approve the transaction, subject to having certain agreements in place. The other six shareholders involved in the transaction include the municipalities of Barrie, Hamilton, Mississauga, St. Catharines and Vaughan and Borealis, a division of the Ontario Municipal Employees Retirement System and a shareholder of Enersource.

"The merger is a win-win for customers and shareholders," said merger spokesman John Crean. "By generating cost savings through significant economies of scale, the merger will reduce the rising cost of electricity for customers and improve returns for municipal shareholders - monies that can be invested back into communities. By maintaining competitive local distribution rates, the communities also remain attractive to new investment, which benefits all municipal taxpayers and electricity ratepayers."

Once the agreements are finalized, details of the transaction will be forwarded to the Ontario Energy Board for regulatory approval, a process that is expected to take several months. When the transaction is completed, the new utility will deliver electricity and related services to more than 900,000 residential and commercial customers in the Greater Golden Horseshoe area, making it Ontario's second largest local electric distribution company.

Background on the merger is available at: *www.enersource.com; www.horizonutilities.com; www.powerstream.ca*



THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

The Changing Landscape of Asset Management in T&D

The landscape of asset management in T&D is changing rapidly. After decades of relative stability, the need to incorporate smart metering and smart grids to accommodate renewables and distributed generation is putting increasing pressure on asset managers. At the same time a growing number of regulatory bodies are moving to risk-based frameworks, forcing a re-think of how we manage our fleets of aging assets. Finally, the new ISO 55000 standard that was released in early 2014 is gaining traction in the utility space and is raising the bar of what is considered 'competent' asset management. EET&D spoke to Boudewijn Neijens of Copperleaf about these important developments.

EET&D: It looks like asset management is caught in the eye of the storm right now. How can asset managers safely navigate through this rough patch?

BN: These are turbulent times indeed. The old British poster 'keep calm and carry on' comes to mind, and interestingly the Brits are indeed coming to the rescue: much of the new thinking around best practices in asset management comes from the UK-based Institute of Asset Management (IAM). For the last twenty years they have been publishing a growing body of knowledge in this space. They also triggered the international effort that recently brought us the ISO 55000 standard for asset management.

EET&D: There is considerable excitement around ISO 55000. Tell us more about this new standard.

BN: It is important to understand that the ISO 5500x series are management standards for asset management, in the same way that ISO 9001 is a quality management standard and ISO 33001 is a risk management standard. In other words, these standards do not address technical issues; they set the scene for the management processes and systems one would expect to find in well managed companies. Since T&D organizations typically manage billions of dollars' worth of assets, a standard in this area is welcome news.

It has the merit of highlighting and clarifying some of the core principles that should be used to manage assets. In particular, it outlines the importance of two core concepts:

- the fact that assets are only relevant if they generate value for the company and its stakeholders; and
- the fact that assets can fail to perform their assigned tasks and that the risks attached to such failures must be understood and managed.

More importantly, the standard gives us a great vehicle to elevate the asset management debate to the leadership level in many companies. It reinforces the view that asset management is not a form of glorified maintenance, but actually impacts all aspects of an asset-intensive corporation.

EET&D: How will this affect T&D organizations in particular?

BN: In most markets T&D operators are monopolies and as such heavily regulated. As expected, these economic regulators are very interested in the new ISO standard since it gives them a ready-made asset management framework developed with input from relevant stakeholders and vetted by international experts. I expect quite a few regulators will gradually push T&D operators to adopt the standard, either by demanding formal certification or by requiring demonstrable alignment with the standard's spirit. In effect, regulators will want to see proof of competence in the area of asset management. This is already the case in the UK and in the Netherlands, and quite a few North American regulatory bodies are following these developments with interest.

Other stakeholders are also showing interest in the standard, most notably insurers who want proof that asset risk is well understood and managed; and the legal community which will see the standard as the minimum level of duty of care that should be expected of the asset operator.

All this explains the flurry of activity in various industry sectors to interpret the standard and provide additional guidance directly applicable to each sector. The water & waste industry in Australia has already published its own guide to implementing ISO 5500x, under the assumption that the industry regulator will soon expect compliance. Similarly, the rail sector is producing a set of rail-specific international guidelines. In the T&D world, Cigré has just launched a workgroup that I'm chairing, tasked with producing guidelines around the general process assessment steps and information requirements for ISO 5500x for utilities.

EET&D: You mentioned risk and value as core concepts. Can you expand?

BN: In many organizations risk is primarily seen as something driven by the outside world (e.g. the risk attached to changes in oil price) or attached to project execution (e.g. the risk of project delays or cost over-runs). But in asset-intensive organizations a large part of the risk picture is linked to existing assets. An asset failure can have serious consequences, both on service levels and on safety and environmental fronts. This means we need comprehensive and up-to-date asset plans for critical assets to ensure their ongoing performance and reliability, and ultimately, to deliver on the strategic objectives of the company. Moreover, most assets degrade over time, underlining the importance of a robust asset sustainment strategy to mitigate asset risk: doing nothing is not an option.

This has driven the need for improved decision analytics. Without getting into too much detail, an organization needs processes and systems to address the following aspects:

- Descriptive analytics: describe the current state of the assets (e.g. condition scores or health indexes) and leverage this data to determine immediate intervention needs;
- Predictive analytics: use the data collected above to feed models predicting future asset condition, risks and needs – i.e. inform a credible long term plan;
- Prescriptive analytics: based on the needs identified above, build intervention strategies and decide on the best use of the organization's limited resources (financial, human, equipment, etc.) using optimization and simulation tools.

In this context, the concepts of value and risk are key vehicles allowing asset managers to communicate with other internal stakeholders (think finance, engineering, planning) and with external parties (the board, regulators, etc.). They allow us to quantify the value of investing or re-investing in our assets, thereby leading to more rational and defensible decision making.

EET&D: You mention decision making. How do T&D organizations compare to other sectors in this respect? Are we in the lead?

BN: Decision making is a fascinating subject. I'm always amazed how poorly we are equipped to make key decisions, be it in our personal lives or for business. In many cases we heavily rely on expert opinions, which are certainly useful but should be supported by data and rigorous processes to ensure decision making is systematic, consistent and transparent. In my experience, organizations often have a relatively well structured process for large new build projects, but sustainment decisions are not as well managed. Yet there are generally many more sustainment decisions to be made, and these generally consume the largest part of our financial and human resources.

At Copperleaf we often use a five-step decision-making maturity scale to gauge where our customers are and want to be.

Source: Copperleaf Technologies

I'd say T&D organizations are no better or worse off than other asset-intensive sectors but face unique challenges disrupting their businesses, which make effective decision making even more crucial. We therefore see T&D companies as being in the lead when it comes to exploring best practices in asset management and adopting best-in-class solutions.

EET&D: We often hear that standards are merely a tick-box exercise and deliver little value to organizations. What is your view?

BN: The benefits you extract from the alignment to a standard or to a set of best practices are entirely under your control. Some organizations might elect to go for a minimal effort simply to obtain certification. Others will use this initiative as a catalyst to become excellent at asset management. There is growing evidence that companies aiming for excellence reap significant benefits. For instance, a major Dutch electrical and gas utility has managed to improve its reliability to become the best in the country. It improved its safety record by 25 percent while at the same time becoming the lowest-cost operator, without affecting the financial bottom line. On the 'soft' side, its employees now understand the asset management processes much better, its board is now fully engaged in rational discussions using risk and value as key metrics to approve major capital decisions, and the economic and safety regulators fully trust the company.

EET&D: How do you recommend starting such a journey?

BN: Often it's a matter of starting with a gap analysis. Where is your organization today, and what end state do you want to aim for? Then it's a matter of breaking the project down into manageable chunks. We see many organizations starting with a proof of concept in a particular department, and possibly limiting the scope of the first phases to items that can quickly deliver results and increase the level of buy-in and interest in improved asset management. For instance, building a value framework that allows organizations to effectively evaluate the true contribution of each proposed project in alignment with the strategic objectives of the organization can be an eye opener and a very useful first step. Similarly, many organizations will want to spend time early on refining their risk matrix to ensure everybody uses a consistent model to quantify risks, and that only risks that matter to the organization are taken into consideration.

EET&D: We can't thank you enough Boudewijn for taking the time out of your schedule to chat with us. At the rate asset management is changing and growing in T&D, it's good to know technology is keeping up the pace.

White papers on the importance of value and risk in decision making can be found at *www.copperleaf.com*. For more information on best practices in asset management visit the Institute of Asset Management's website *www.theiam.org*.

About the author

Boudewijn Neijens holds a Master degree in Mechanical Engineering from the University of Brussels, an MBA from INSEAD in France, is a Certified Asset Management Assessor and holds a Certificate of the Institute of Asset Management. He has been involved with high-technology start-ups for the last 25 years, currently in the fields of asset management and environmental data processing. He is Chief Marketing Officer at Copperleaf Technologies in Vancouver, BC. In this role he works with large asset-intensive corporations around the world to refine their asset management practices in the areas of Asset Investment Planning and Management, decision support systems and risk-based planning models. He is the president of the Vancouver chapter of the Plant Engineering and Maintenance Association of Canada, and the Vice-Chair of the Canadian chapter of the Institute of Asset Management.

GREEN OVATIONS

Innovations in Green Technologies

SMUD's Do-No-Harm Approach to Vegetation Management earns Environmental Praise

By Steve Hallmark

Sacramento has long been called the City of Trees. In the 900-square mile area we serve, SMUD's vegetation management team performs vegetation inspection and planning, and oversees the maintenance of more than 200,000 trees. That's just the beginning of the story because our team also maintains the easements and rights of way in or adjacent to SMUD's generation, distribution, and transmission infrastructure, much of it in the foothills and mountains of the Sierra Nevada.

Every year, we manage more than 500 miles of transmission right-of-way corridors in order to ensure reliable, safe delivery of electrical energy throughout the SMUD system. Regular schedules to clear vegetation away from power lines, poles, transformers, substations, and other various SMUD facilities are vital to reduce the chance of power outages.

The transmission corridors are key not only to SMUD's power grid, but also the grids of the utilities that comprise the Balancing Authority of Northern California (BANC). BANC is a Joint Powers Authority that matches generation to load and coordinates system operations with neighboring BA's. These include SMUD, Modesto Irrigation District, Roseville Electric, Redding Electric Utility and Trinity Public Utility District as its founding members. BANC is the third largest Balancing Authority in California and the 16th largest Balancing Authority within the WECC area. Millions of northern Californians' electricity needs are dependent on the system and it's crucial that every preventive measure is taken to keep the lights on,

Balancing power, reliability, and the environment

SMUD has always been very concerned and very diligent about our environmental footprint. As a utility, we have realized trees' value and benefits for a long time. Not only do local, state, and federal laws require vigilance in maintaining vegetation near our facilities, our board of directors does, as well. As a municipal utility, a board of seven directors elected by our customers sets our policies, and SMUD staff is responsible for carrying out those policies.

Environmental leadership is part of our vision statement and is a core value of SMUD set by our board, which is committed to it through community engagement, continuous improvement in preventing pollution, reducing carbon, energy efficiency, and conservation. Our board mandates that we conduct our business affairs and operations accordingly.

Balancing the competing constraints of keeping the power on and Mother Nature happy presents a significant challenge, which we meet every day.

Recognition for our work

In October, the Right of Way Stewardship Council (ROWSC) approved SMUD as a founding accredited utility. ROWSC is an accreditation program that establishes standards for responsible right-of-way vegetation management along transmission corridors. The program promotes the application of Integrated Vegetation Management and best management practices in order to maintain power system reliability and address ecological concerns.

The accreditation provides standards of excellence with regard to maintaining easements and rights of way for environmental stewardship and presents the opportunity for companies to demonstrate their commitment to such standards.

The recognition makes SMUD just one of seven founding accredited utilities and power companies in the United States along with Arizona Public Service, Vermont Electric Company, New York Power Authority, Pacific Gas and Electric (PG&E), Bonneville Power Administration, and AltaLink in Alberta, Canada.

SMUD is honored to earn the distinction. It has real value in the utility industry. The ROWSC design follows the lead of the Electric Power Research Institute's Standards for Assessing Performance of Integrated Vegetation Management on Rights-of-Way and is modeled after other well-established accreditation programs found in the forest industry such as the Forest Stewardship Council and Sustainable Forestry Initiative. The ROWSC has established management standards based on a set of predetermined principles, requires a formal application process, and enlists third-party auditors to ensure compliance with standards.

As ROWSC stated in its awarding of the accreditation: "This third-party recognition by ROWSC ensures an independent, proven process to convey credibility and bring recognition to IVM programs. The benefits of the accreditation reach beyond the practitioner's sphere; it has the potential to positively impact the industry, communities, stakeholders and agencies."

Fire prevention

The accreditation also means we're doing everything we can to keep our communities safe. If not managed properly, tree branches if allowed to grow too close, or hazard trees adjacent to transmission and distribution lines, can catch and cause fires and/or damage the lines causing our customers to go dark. Being selected as a ROWSC accredited utility means that we're doing everything in our power to proactively manage vegetation and keep our customers safe and their lights on.

Late in the summer of 2014, arson sparked what's known as the King Fire, which scorched nearly 100,000 acres of El Dorado County, in the Sierra Nevada. Some of that fire came very close to our transmission facilities which move power generated from our Upper American River Project (UARP) hydroelectric plants. The UARP, which we call the Stairway of Power, includes 11 dams, 8 powerhouses containing 11 turbines and six auxiliary dams and dikes. The UARP's generating capacity of 688 megawatts of clean, non-carbon-emitting electricity, in a good water year, provides SMUD with about 20 percent of our power mix.

Firefighters from across California valiantly battled the flames for several days to gain control. Bravery, teamwork and mutual aid delivered success, as did a timely rainstorm. SMUD's resources also helped immensely. Particularly, SMUD's reservoirs holding precious water were valuable to ground and airborne firefighting efforts. Roads to SMUD UARP facilities provided easier routes to quickly and effectively transport firefighting personnel and equipment deep into heavily forested areas. A crucial turning point in the battle came from SMUD's transmission line rights of way that had been cleared and vegetation maintained which minimized the fuel under the lines. Those transmission corridor rights of way provided critical fire breaks for firefighters in slowing and eventually stopping the fire's spread.

Starting in early May 2015, SMUD and PG&E began vegetation management work in the adjacent area to Apple Hill to reduce the threat of wildfires and ensure reliability of high-voltage electric transmission lines focused near the area where the King Fire burned. In light of the severe fire-related risks caused by California's prolonged drought, this work is crucial in minimizing fuel sources and preventing a repeat of the disastrous King Fire.

Going forward

SMUD has earned a lot of respect from environmental groups over the years for our efforts. We work hard to leave the areas where we work the way we found them respecting the leave-no-trace philosophy that is typical of all SMUD projects. When we do need to intervene in the natural habitat, we do so to make the situation better and safer. The ROWSC accreditation is affirmation of that approach. We encourage other utilities to seek the accreditation. It's good for our industry and even better for the common good.

About the Author

Steve Hallmark is SMUD's Manager of Vegetation Management. Steve has more than 30 years of utility vegetation management experience. He is considered a very knowledgeable subject matter expert on a national level.

In addition to his work at SMUD, Hallmark currently serves as the Chair for the Vegetation Management Practices Core Team of the North American Transmission Forum. He is a past president of the Utility Arborist Association, and has published articles in the Edison Electric Institute's Electric Perspectives, International Society of Arboriculture's Arborist News, and the Society of American Foresters Journal of Forestry.

Steve Hallmark's current role includes responsibility for SMUD's Transmission and Distribution Vegetation Management program, including budgeting, regulatory compliance, contract design and enforcement, government and industry liaison, and he serves in a leadership capacity on vegetation management issues.

Hallmark earned a Bachelor of Science in Forest Management from Stephen F. Austin State University in Texas in 1981 Steve may be reached at *steve.hallmark@smud.org*.

From Research to Action

An Opening Glimpse of EPRI's Open Enabling Platform

By Karen George

The electricity grid has become increasingly dependent upon information and communication technologies. Advances in sensor, networking, software technologies, and increases in their deployment are continuing apace, adding to this dependence.

According to Matt Wakefield, director of EPRI's Information, Communication, and Cyber Security Program, this interdependence is a necessity of an integrated grid. "Devices and systems need to be interoperable and seamlessly connected. Just a few examples include the growing need to communicate with and manage distributed energy resources like solar photovoltaic installations for grid support, enabling the utility workforce with new tools, and adding intelligence at the grid edge—and doing all this in a secure manner. Not having a platform in place to be able to quickly adopt innovative technologies has been a barrier, forestalling the benefits associated with advanced systems and networks."

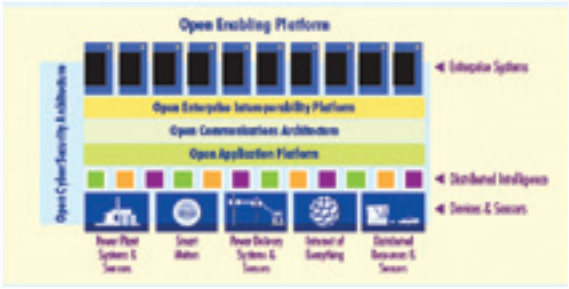
Wakefield's comments stem from the initial results from a recent demonstration of a multi-year EPRI Breakthrough Technology Innovation project. This project was initiated to help utilities with the development of an open enabling platform that will support the integration of the electric grid with information and communication technology (ICT) infrastructure.

Convergence, as defined by the U.S. Department of Energy,[1] "is the transformation of two or more networks or systems to share resources and interact synergistically via a common and seamless architecture, thus enabling new value streams."

In collaboration with multiple industry partners, EPRI's goal is to help utilities create their own 'common and seamless architecture' by creating an open enabling platform.

An Open Enabling Platform

EPRI's open enabling platform (OEP) brings together four elements supporting seamless and secure interoperability among conventional power generation and delivery systems, back-office networks, distributed resources, and the integrated grid.



The platform is being designed for adoption by electric utilities at any stage of technology deployment. Following this design goal gives technology developers the incentive to pursue open, standards-based solutions. The goal of the OEP is to maintain the functionality of existing systems and devices that have remaining useful lifetimes—while being sufficiently agile to take advantage of rapidly evolving technologies and accommodate ICT innovations and grid-connected applications not currently deployed.

Four distinct but interconnected elements of an OEP are being incorporated in EPRI's testbed.

- Open enterprise enabling platform – ties together all elements of an open enabling platform to achieve interoperability between applications, software, services and systems across the utility enterprise, with partners, and beyond the meter. The goal is for disparate utility systems – modern, legacy, and emerging – to interact and work together through advances in semantic messaging, including the incorporation of non-standard messages into existing standards.
- Open application platform – analogous to the operating systems of smart phones and tablets, the open application platform will provide secure access to internal data elements residing in diverse systems and sensors. This will enable development of apps that expand functionality and increase the lifecycle value of utility devices such as advanced meters, supervisory control and data acquisition system networks, field transmitters, communications gateways, capacitor banks, regulators, switches, and other controllers.

- Open communications architecture – an architecture that enables IP-based innovations in wired, wireless, and powerline carrier communications to provide reliable, robust, high-bandwidth, low-cost communications. This will allow access to systems and sensors in challenging operating environments and at utility sites, the edge of the grid, and beyond.
- Open cyber security architecture – an architecture to integrate the disparate localized solutions required for the protection and monitoring of systems and sensors internal and external to the enterprise. These architectures will span the open interoperability and application platforms and associated systems and sensors, enabling both centralized and distributed system analysis, protection, and control strategies.

The progress being made in the development for each of these elements was demonstrated in EPRI's Knoxville Labs in October 2015.

Wearable Computers and the Enterprise Interoperability Platform

EPRI is developing use cases, data models, and a conformance testing platform to support interoperability evaluations for the enterprise platform. In the first year, the focus has been 'Wearable Computer to Work Management System Integration,' with development of standards-based messaging infrastructure.

Applications of wearable computers include augmented reality, which is a live, direct or indirect view of a physical real-world environment whose elements are augmented by computer generated sensory input such as sound, video, graphics or geospatial data. If you have watched a U.S. football game on television, you have seen augmented reality: the computer-generated yellow first-down line overlaid on the image of the real field.

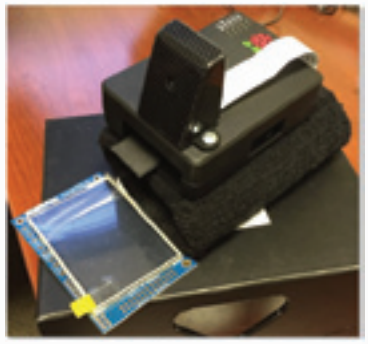
There are multiple uses of wearable computers using augmented reality, for example, when assets can be mapped and located as shown below. Wearable computers can also include sensors that can measure data not readily detected by a field worker with the naked eye, such as heat behind a panel or an electrical charge in a fence.

Example of a tablet computer, overlaying augment reality information on a display, showing the location of utility assets.

The wearable computer market has exploded in recent years, with new entrants developing their own new messaging infrastructures. This creates a dilemma for utilities that want to acquire the technology. As noted by Dr. Gerald Gray, a technical executive at EPRI who is leading the development of the open enterprise platform, "Regardless of the initial vendor selected, chances are that a particular device will not be available in the next five years as the wearable computer domain shakes out. Like the desktop computer market of the 1980s, there are multiple products, and many are likely to exit the market or be acquired."

To address this issue EPRI is creating a standards-based messaging infrastructure for wearable computer technology based on IEC 61968-6 Maintenance & Construction, which was published in 2015. With standards-based integration, a utility will need only change the device – the messaging infrastructure survives intact. Per Gray, "Being able to change the device helps ensure 'no regrets' investment decisions."

EPRI demonstrated the integration of a Raspberry-Pi based wearable computer at its year-one demonstration, generating a work order using CIM² messages from the wearable computer, which captured and attached pictures, video and geospatial coordinates. Data was transferred in CIM-based work order messages into the OpenWMS (workflow management system) tool.



A Raspberry-Pi based wearable computer produced CIM-based work order messages

EPRI has also created a test harness, which is software that allows testing of messages under a variety of conditions, to verify that a client's messages can be consumed if they are correctly formed. "Having a standard way of messaging lowers the barriers for vendor adoption of this infrastructure;" said Gray, "once they comply with the messaging, vendors can then focus on price, performance, services, and features of their particular devices."

Smart Meters and the Open Application Platform

In the same fashion that smart phones allow for enhanced functionality with available applications (users can choose from 1.6 million apps for Android and 1.5 million apps for iPhone as of July 2015[3]), the open application platform will allow utilities and others to independently add new applications to products and establish uniform functionality across multiple product brands.

EPRI is creating an open application platform, extending a smart meter program interface to address a broader array of use cases. Laboratory and field tests of an open platform prototype are being conducted in coordination with industry partners, using apps that introduce new functionalities to high-priority devices.

At the year-one demonstration, Ed Beroset, principal technical leader at EPRI, offered a vision of the open application platform, "That starts by imagining you had a word processing appliance, an email appliance and a web browsing appliance. Now let's say you want to do some calculations with a spreadsheet. Instead of buying yet another single-purpose appliance, you'd probably prefer to have a more general purpose device that could do all four of those applications and more."

This is the idea behind the open application platform, which provides a secure, open, standardized platform on which new applications can be built. The demonstration unit in the photo below shows two different applications running simultaneously on hardware similar to that in current generation smart meters. Instead of being limited to only the functions that were originally imagined by a meter designer, the open application platform allows utility personnel to add new functions, even after device installation.

Photo by Saul Young/Knoxville News Sentinel
Ed Beroset discusses creating apps for advanced meters at the EPRI open enabling platform year-one demonstration.

"Applications in this platform could be long term or only be deployed temporarily as needed, such as an application that validates transformer association with a meter," Beroset said.

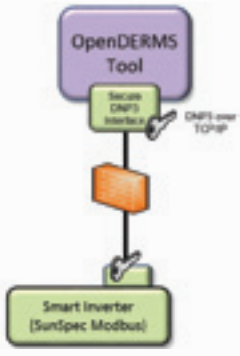
Vendor Devices and Open Communications Architecture

EPRI recognizes that an integrated grid relies on telecommunications to transfer data between devices – between the field and enterprise – and now with Open Field Message Bus (OpenFMB), between devices in the field. Devices and systems need to communicate with each other and the utility back office to be interoperable.

Tim Godfrey, Principal Technical Leader at EPRI, working with Ben Rolfe, Strategic Technology Consultant with Blind Creek Associates, and Gene Falendysz, Principal Design Engineer at Itron, demonstrated how the open communications platform can work, implementing the Field Area Network (FAN) standard from the industry group Wi-SUN Alliance. The standard enables interoperable communication networks.

"Just as the WiFi Alliance, Bluetooth, and USB are ubiquitous plug-and-play items in your life," said Ben Rolfe, "the EPRI Wi-SUN communications open platform can become ubiquitous in the utility industry."

The interoperability tests at the demonstration—communicating with an Itron device—proved successful. EPRI, Itron, and other Wi-SUN Alliance members participate in an ongoing series of interoperability testing events. These tests help identify any discrepancies in the interpretation of the specifications, in which case the specifications can be refined to a point of yielding only one interpretation.



Gene Falendysz reported that Itron, as well as others in the Wi-SUN Alliance, are behind standardizing on an IP network and seeing the ecosystem evolve to enable communication between disparate devices and systems in any type of operating environment.

EPRI's Godfrey pointed out that the standard focuses on metering, but it can also support distributed energy resources and some types of distribution automation. "Going forward, we plan to achieve Wi-SUN certification for our platform. We will also develop application layer tools that will provide a new level of visibility into the network. We hope to see our platform used as a basis for innovative products, and used by utilities as a 'gold standard' for confirming interoperability."

Open Cyber Security Architecture

How can an open enabling platform be achieved in a secure manner? EPRI's first year activities started with the integration of secure authentication for the Distributed Network Protocol, version 3 (DNP3).

Glen Chason, Senior Technical Leader in Cyber Security at EPRI, explained that DNP3 is widely used in the utility industry and that secure authentication with DNP3 has been the initial focus because field devices can support this type of security. "It is well suited to the prevention of 'man-in-the middle' attacks, to which field devices may be especially vulnerable," said Mr. Chason. The man in the middle is an attacker who masquerades as a master to an outstation and as the outstation to the master. Verifiable authentication prevents the attacker's access at the out- and master-stations.

A Distributed Energy Resource Management System (DERMS) that provides a testbed for evaluating interoperability with other secure authentication solutions was used for the OEP testbed demonstration, and it is allowing for the testing of both devices and architectures.

EPRI plans to validate the instantiation of a Distributed Key Management Protocol server to expand the capabilities of the testbed. Also planned for the future is an implementation of the Open Field Message Bus (OpenFMB) framework testbed for security testing of the framework.

This cyber security platform can serve as an ongoing testbed for evaluating proposed cyber security solutions for end-to-end interoperability and the security of field devices, open application platforms, communications, and the whole enterprise.

Conclusion

The EPRI demonstration was just a glimpse into the steps to creating an open enabling platform. In coming years, EPRI hopes to help utilities achieve interoperability and the optimal convergence of the electricity and ICT infrastructure—and accelerate adoption of rapidly evolving technologies in a manner that is secure and optimizes operations and value.

For more information about EPRI's Information, Communication and Cyber Security work visit www.epri.com.

About the author

Karen George, Technical Leader, Information and Communications Technology in EPRI's Power Delivery & Utilization program, has more than 30 years of experience in the energy industry, specializing in technology transfer related to renewable energy resources and end-use efficiency. She is currently engaged in projects related to integration of distributed energy resources, most recently with the EPRI Smart Grid Demonstration Initiative, a seven-year project involving 24 utilities in the U.S., Australia, Canada, France, Ireland, and Japan.

[1] Pacific Northwest National Laboratory, The Emerging Interdependence of the Electric Power Grid & Information and Communication Technology, PNNL-24643, August 2015.
[2] CIM is the Common Information Model, a standard developed by EPRI and the electric power industry to support the exchange of data and messages. See the freely available Common Information Model Primer: Third Edition. EPRI, Palo Alto, CA: 2015. 3002006001.
[3] The number of smart phone applications available is from satista.com/

RecX: Prototype spare transformer sets the stage for substation resiliency

Rapid Recovery Transformer advancements – as well as new assessment, monitoring, hardening and rapid repair capabilities – can help utilities boost grid reliability and minimize exposure to potential attacks and outages

By Craig L. Stiegemeier

The grids that make up North America's power infrastructure have had a long, proud history of relative stability over the past century. And the U.S. electric utility industry has earned a long, well deserved track record of reliability. Extended outages have been rare.

The financial and emotional impact of a long-term outage on a nation cannot be underestimated. For example, the damage that led to astronomical costs associated with regional severe-weather related outages such as Superstorm Sandy, the major hurricane and severe weather system that hit the Northeast in 2012, directly impacted the economy as well as the U.S. presidential race. In 2012, a Congressional Research Service study estimated the inflation-adjusted cost of weather-related outages at $25 to $70 billion, annually. Fortunately, proper planning and quick reaction following Sandy kept major outages under control, and power was restored to more than 95 percent of customers within two weeks.

Storms and Snipers

And now in this post-9/11 era, on top of these major weather-related disaster concerns, comes a wave of physical attacks on targeted substations and power transformers around the country. Between 2011 and 2014, according to USA Today, electric utilities reported 348 physical attacks that caused outages or other power disturbances.

The most high-profile incident occurred in 2013 in California, where snipers took direct aim at a unidentified substation serving Silicon Valley by cutting hard-wired communications and firing high powered rifle shots at 17 transformers and six circuit breakers, causing 52,000 gallons of oil to be spilled and $15.4 million in estimated restoration costs. Fortunately, there were no significant outages, as there was a massive – and successful – effort to reroute power and restore service.

These physical attacks led the North American Electric Corporation (NERC) to quickly file a petition for the approval of reliability standard NERC CIP-014 requiring transmission owners to assess the vulnerability of critical substations and development & implement security plans. The implementation schedule for this order started in October, 2015 and requires completion by August 2016. NERC created this project to address the directives issued in the *FERC Order on Reliability Standards for Physical Security Measures* under Docket No. RD14-6-000 issued March 7, 2014.

The importance of power transformers

Large power high voltage (HV) transformer units today make up less than three percent of the total number of transformers on the grid; however, they carry 60-70 percent of the nation's electricity, so it is vital to protect these assets.

Power transformers are widely recognized to be the most critical asset in the substation. Many utilities have some version of spare transformers on hand, however there is a very limited availability of spares. Spares are often in the same location as a potential attack, and there is rarely more than one available per substation. Every transformer in America is designed for a particular application, and few transformers are alike, especially at high voltages. Manufacturing lead times are long, and involve complex processes around design, procurement, production, testing and deployment. There are difficulties with transportation, as large, heavy units are rarely able to be transported on trucks. Most transformers are shipped via rail transportation, which often takes weeks of planning and implementation. And finally, there is much specialty equipment and skills required in the installation of these transformers. Dimensions are critical. Many times, new concrete pads must be created, and many hours of civil work are required.

Absolute physical security of America's grid infrastructure or its substations is not practically achievable if not downright impossible. Vulnerabilities hinge on attackers' intentions, skill and resources. There is no way to absolutely protect a substation transformer and other electrical equipment from severe damage from an intentional attack. It is possible to make the damage less severe, prolong service and restore service more quickly with a layered approach to physical security. When damages exceed repair capabilities, rapid replacement strategies play an important role in transformer recovery. Critical transformers need spares, universal spares, and an on-the-shelf design for critical assets.

Successful 'RecX' Concept Demonstration

In 2012, a new consortium led by the U.S. Department of Homeland Security (DHS), which included ABB, the Electric Power Research Institute (EPRI), and CenterPoint Energy, launched a new Rapid Recovery Transformer (RecX) program. The concept actually began prior to 9/11 with EPRI's Infrastructure Security Initiative (ISI), where the feasibility of a fast-to-install transformer design was first examined. ABB was tasked with designing a conventional oil-filled spare transformer with ease-of-transport and fast-to-install concepts. DHS became involved after the project created a less-than-one week storage to transformer energization concept. And CenterPoint, the utility host, supported a trial deployment and designated one of its substations to house the first RecX.

The RecX consortium held a timed concept demonstration, a 'fire drill' for deployment of the spare transformer, in 2012. The consortium would transport this prototype transformer that could replace a failed extra-high-voltage (EHV) transformer in about a week as opposed to several months. A trio of single-phase 200-MVA, 345/138-kV autotransformers would be disassembled, loaded onto a specially designed over-the-road trailer, transported more than 900 miles (1,448 km), reassembled and energized in less than one week in the designated substation. RecX comes with its own optional pad and does not require the use of a crane to unload, a big time saver as opposed to pouring and curing a concrete base. One of the units in the demo came with this pad.

The drill began on a Monday morning, March 12, 2012 at the ABB transformer manufacturing plant in St. Louis, Missouri. The partially assembled unites were pulled from storage, simulating an actual emergency scenario, and placed onto two conventional lowboy trailers and a 65-ton capacity trailer (MA65) specially designed for a trip to Houston. The MA65 was modeled after an over-the-road Schnabel railcar, and proved to be amazingly versatile.

The trailers all arrived by Tuesday evening, and assembly began on Wednesday morning. And on Friday evening, after experienced CenterPoint assembly crews worked 12-14 hour days and much of the testing and installation was done, it was near completion. The project was indeed completed on Saturday morning, March 17. The RecX transformer and associated units were successfully energized by Saturday evening – Five days, 10 hours, and 10 minutes after the simulation first started. A one-year monitoring period for evaluating performance was then successfully started and completed. And today, as of late 2015, the RecX prototype spare transformer is still humming along and working as originally designed.

Utilities have noted the RecX's large power capabilities, allowing for high voltage ratings; its compact and flexible design, including three individual single-phase units, hybrid NOMEX® insulation system for reducing size while maximizing power, and its remote cooling system. Just as important, these spare transformers enable rapid deployment, with transportation and installation now happening in days versus weeks.

A recent study concluded that the single most utilized transformer in the U.S. holds a voltage ratio of 345-138 kV. This demonstration exercise successfully created, deployed and energized three single-phase 200 MVA, 345-138 kV units that are small enough to be transported over U.S. Interstate highways, dramatically reducing transport times as compared with conventional rail transportation.

Five Steps to Better Substation Resiliency

Since the first Rapid Recovery Transformer (RecX) was first installed in 2012, technology advancements have continued and the power industry has come together to begin working out the complex weave of economic, security and practical concerns. The U.S. Department of Energy (DOE) has picked up where DHS left off, issuing a well-received report, 'Large Power Transformers and the U.S. Electric Grid,' around how the loss of large power transformers (LPT's) could result in grid exposure. NERC CIP-014-1 has been initiated, requiring utilities to be compliant by August 2016.

And ABB, in consultation with several electrical utilities and the DOE, has recently launched a '*Substation Physical Security and Resiliency Initiative*' to help utilities reduce the impact of and quickly restore the grid after a natural or man-made disaster. This initiative covers five strategic elements that will help these utilities restore power as quickly as possible. These steps include:

- **Assessment** – Assess the asset risk to extreme weather events, intentional criminal attacks, geomagnetic disturbances (GMD) and electromagnetic pulses (EMP)
- **Hardening** – Harden substations and power equipment against malevolent attack and extreme environments
- **Monitoring** – Remote monitor the asset and surroundings and automate response to abnormalities
- **Rapid Repair** – Rapidly repair lightly damaged power equipment, allowing utilities to quickly restore their equipment following an incident
- **Rapid Replacement** – Rapidly replace severely damaged power equipment

Currently, DOE is preparing to submit a plan to the U.S. Congress evaluating the feasibility of creating a strategic transformer reserve for strategic storage of spare LPT's in sufficient numbers to temporarily replace severely damaged power transformers. This plan would include a description of the appropriate number of spare transformers needed as well as total capacity in megawatts as well as strategic locations for transformer storage, and the easiest means for quickly transporting, installing and energizing these spare transformers.

It is important to note that even the new generally interoperable and rapidly deployable transformers can only reduce the time it takes to transport and energize an LPT. It still takes several months to manufacture one of these units. Should an event occur that requires a replacement transformer, if one has not already been built, then utilities would still face a long delay in energizing a new transformer. But having appropriate reserves of large power transformers located at strategic points nationwide, would fill a challenging gap in the timing of LPT repair and complement existing industry programs.

The advantages and potential of these rapid recovery transformers, coupled with wider access to spare large power transformers and the ability of utilities to quickly assess, monitor, harden and replace this equipment, will better prepare our power grid for any emergency situation in the coming years.

About the author

Craig L. Stiegemeier is Business Development and Technology Director for ABB's North American Transformer Remanufacturing and Engineering Services (TRES), and is responsible for developing effective processes supporting condition evaluation and assessment tools, life extension solutions and training programs for utility and industrial users of power transformers. Craig led the design of the RecX transformer and provided leadership to the RecX consortium with the Dept. of Homeland Security. Craig and his family are based in St. Louis, Missouri. Craig may be reached at: *craig.stiegemeier@us.abb.com*.

New ballistic protection system is unveiled for transformers under fire

ABB, as part of a new substation and grid resiliency initiative, has just introduced AssetShield™ a first-of-its-kind solution to shield and protect large power transformers and other substation equipment from ballistic attack. AssetShield currently meets UL-752 Ballistic Standards – Level 10 Rating.

AssetShield is an impact and fragmentation-protective system for substation equipment such as transformers, switchgear, circuit breakers, and capacitors. It reduces the kinetic energy of the bullets and reduces spalling after impact.

The U.S. is more dependent than ever on reliable electric power for residential, commercial and industrial use as well as strategic security. However, a physical or terrorist attack on the grid could result in widespread power outages and significant economic losses for utilities and the nation. The loss of certain large power transformers (LPTs) could result in exposure to the grid.

The North American Electric Reliability Corporation (NERC) has recently issued the first draft of a standard for physical security measures (CIP-014-1), mandating that all electric utilities identify and protect critical substations within their system. AssetShield has been tested to protect transformers and their sensitive components by withstanding various types of gunshots at varying distances.

"Absolute physical security for a substation is not practically achievable, but with AssetShield and other protective actions, it's possible to minimize the damage, prolong service and restore service more quickly when there is an attack," said Emily Heitman, ABB Vice President and General Manager of Commercial Operations for Power Transformers in North America. "ABB is pleased to introduce AssetShield to support electrical utilities and address security concerns around large power transformer and substation vulnerability."

Drones

What are they? What do they do? What are the good for? What is controversial about them?

By John Kullmann

Thinking specifically of emergency response operations, where do drones fit in – both now and in the future?

These are the questions that utility companies are asking…and need answers to as soon as possible.

Since 2005, Macrosoft has been working with electric utilities across the country to effectively manage resources – people and equipment – for dealing with emergency power outages.

When a major outage occurs, many utility companies use the Macrosoft's innovative tools, Resources on Demand (RoD) and Assessments on Demand (AoD), to determine the scope of the incident, assess the damage, and manage both internal and external resources to restore power.

But, in today's world, where technology is advancing faster than any time in history, there is no such thing as resting on previous successes. The company is constantly monitoring new tools, technologies and trends in emergency response.

And one of the most important, potentially beneficial advances in recent years has been the use of aerial drones for emergency response management.

- What do we know about drones?
- What, if anything, can they do better than current aerial reconnaissance resources?
- What can they not do as well, or at all?
- Are they safe, reliable, and/or cost-effective?

To find out the answers, we conducted a research study among key personnel from utility companies around the country.

Specifically, in August, we conducted online research among utility company personnel, representing a broad spectrum of organizations across the United States (about 80% of the sample) and a number of other countries as well, which included investor-owned facilities (about half the companies surveyed), municipals, and cooperatives.

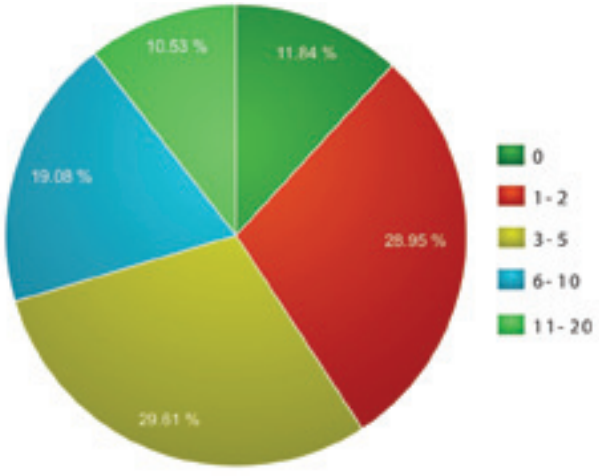
They responded to a series of questions – both closed-ended (i.e. with defined choices) and open-ended (free-form) – covering a wide range of topic areas about emergency response management, including a comprehensive series on drones.

Here is what they told us:

Frequency of Opening Emergency Operations Storm Centers

About 12 percent of respondents were at utility companies fortunate enough not to have opened their Emergency Operations Storm Centers at all last year.

Of the rest, about equal percents (roughly 30% each) opened 1 to 2 times in the past year, 3 to 5 times and 6 or more times – with 10 percent opening 11 to 20 times.



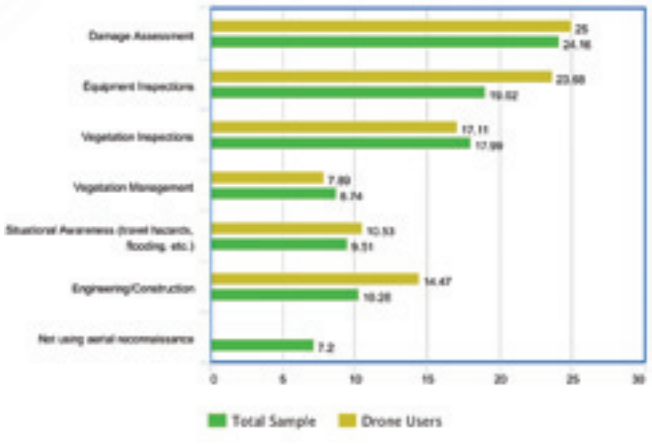
Aerial Reconnaissance

A large majority of utility companies in this study (about 80%) use one or more forms of aerial reconnaissance for emergency operations – mostly helicopters.

They serve a wide range of uses – the most frequent being equipment inspections, vegetation inspections and vegetation management.

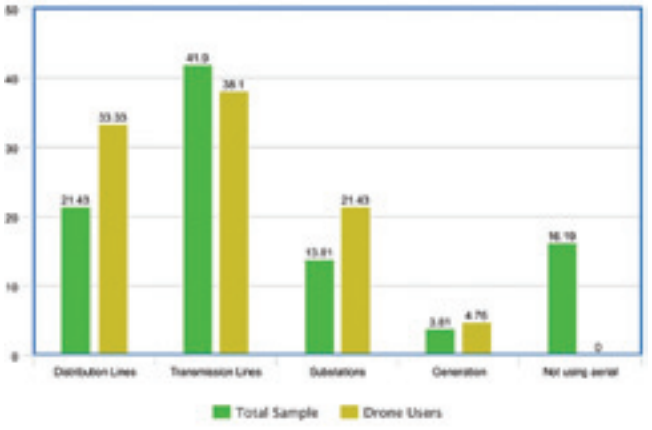
By contrast, only about one in ten companies currently use drones.

It is hard to determine whether this is due to the relative newness of drones as an emergency operations tool (i.e. it's just a matter of time), because the perceived problems with drones – which will be discussed further on – are felt to outweigh their benefits, or because they are considered unnecessary, as helicopters can perform the same functions:



This suggests that emergency utility companies are not fully cognizant of the advantages of drones, and/or have not yet put them to their greatest advantage.

When asked what specific areas aerial reconnaissance is best used for, transmission lines are most frequently mentioned, followed by distribution lines and substations:



How Drones Are Currently Used

Among those whose companies do have drones, several explain how they are used:

"In general, helicopters (are) used for annual transmission OH line and vegetation inspections, semi-annual infra-red thermography of OH lines, and post-disturbance damage inspections… We also use drones for high definition inspections of OH Transmission line structures on lines with significant contributions to SAIDI (inspections conducted inside of the wire zone)."

"(We) use copters mainly but have used drones for remote areas across large bodies of water for damage."

"Drones are in the infant stage but we now have approval and own license from the FAA and are currently testing and utilizing the drones. We are also looking into all benefits of this technology and testing to see the effectiveness of their usage in various departments and aspects of the electrical utility."

Future Use of Drones

Despite the benefits drones afford, and the fact that they are a relatively new technology, only about half of all respondents believe drones will become part of their company's emergency response arsenal.

But, when asked about utility companies (not specifically their own) deploying drones in the future, over 95 percent say they will – and 89 percent expect them to be deployed within the next five years.

This indicates that, although utility professionals believe drone usage is inevitable in the near future, a good many have difficulty envisioning their own utility companies using them.

And what will drones be used for? Damage assessment is considered their single most effective use, with equipment inspections, vegetation inspections and situational awareness bunched relatively closely behind.

Surprisingly, security/surveillance, which drones are deployed for by other industries as well as non-industrial venues, lags a good deal behind.

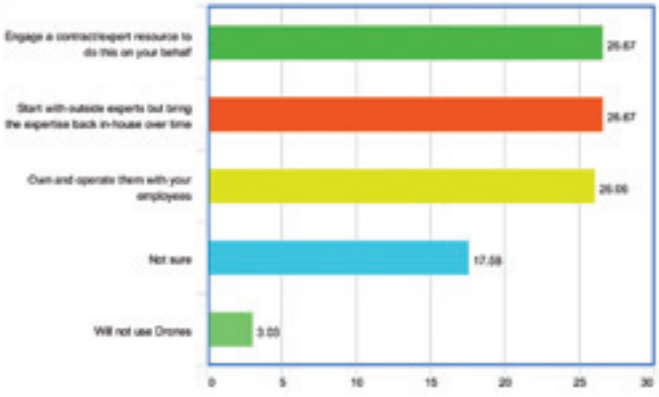
Hindrances to Using Drones

When respondents are asked what factors would hinder their use of drones, FAA regulations predominate as a concern, followed by liability and technical concerns.

Importantly, the cost of drones is at the bottom of the 'hindrance' list, which tells us that, whatever else is thought of them, they are an economical option for air reconnaissance – certainly versus the currently-preferred helicopters.

How Drones Will Be Managed By Utility Companies

Earlier it was noted that drones are new to the utility industry and that this may contribute to the uncertainty shown by study participants about how they might be used by utility companies. This is further demonstrated by the following table:



As you can see, there is no clear direction regarding how utility companies might use drones – with roughly equal numbers of respondents envisioning their own companies either engaging an expert to work with drones, starting with experts but eventually going in-house or owning/operating drones using company employees.

The single most surprising finding of this table, however, is that just 3 percent say their companies "Will not use drones."

Earlier in the study, we saw that only about 11 percent of all respondents said their companies currently use drones, and only about 48 percent said they would be using drones in the future. Yet here – just minutes later - only 3 percent feel their companies will not be using drones – i.e. 97 percent see them doing so.

This again brings home the overriding theme that drones are, at least as of now, a mystery to utility professionals – for both current and future usage.

Payloads

One thing respondents are not at all unsure about, however, is what payloads the drones would transport. Over 80 percent mention cameras – video, infrared, still, or LIDAR varieties.

Types of Drones That Will Be Used

As for the types of drones they foresee? Most expect they will be multi blade copters – with helicopter and fixed wing varieties well behind. But let's remember, again, that:

a) Respondents, as a group, are not very conversant with current drone technology and
b) That technology is rapidly changing, so this might change in the near future.

Conclusions

Drones represent a major opportunity for emergency response operations. But, given the current state of the art, and the limited understanding of their potential by utility professionals, the jury is still out on their usage.

On the positive side, drones offer a combination of reach, speed, safety, and cost that cannot be duplicated by other systems.

On the negative side, however, their usage is heavily restricted by FAA regulations.

In addition, they have a number of significant risks, including:

- Liability (i.e. damage and personal injury)
- Safety (possibly interfering with aircraft, crashing into buildings, property, etc.)
- Privacy (what will the drones be able to see? Is this another area of legal liability?)
- Security

Many utility professionals see drones as an important new resource for emergency response management. But their lack of full understanding regarding how and why drones are used must be overcome as time goes on, for drones' full potential to be realized.

About the author

John Kullmann is Vice President of Marketing and Sales at Macrosoft, a New Jersey Technology company. With more than twenty years' experience, John is a recognized expert in business development efforts for professional services firms. He is responsible for expanding Macrosoft from its traditional roots as a leading software development and system implementation company into an equally accomplished provider of packaged technology products.

Hydro at 10,000 Feet: Modernizing the Renewable Infrastructure

By Bruce Cotie

Aging infrastructure is a well-recognized challenge across our nation's energy system with investor-owned utilities spending a record of $19.5 billion in electric transmission infrastructure last year. Top of mind when considering this challenge are typically T&D lines, older coal generation plants, or outdated substations. Renewables are rarely part of the discussion unless the focus is on integrating newer wind and solar technologies with an aging grid. However, hydroelectric power is one of the oldest methods of producing energy with no air, water, or land emissions, and the age of the country's hydro resources should not be overlooked especially as more utility customers are demanding increased renewable sources.

In the early 1900s hydroelectric power accounted for more than 40 percent of the country's electricity supply. That number has fallen significantly in the last century, but the legacy of hydro power remains. To maintain this legacy of hydro power, utilities are focusing on upgrading hydro plants that generate this reliable, renewable energy source to provide more options for peak generation and customer choice.

Cabin Creek: A 1967 Engineering Marvel

Xcel Energy's largest pumped storage hydro facility, Cabin Creek, is nearly 50 years old. Cabin Creek came online in April 1967 and has provided peak power supply nearly every day since. When built, Cabin Creek was an engineering marvel. It was the highest altitude pumped storage plant in the world, containing the second largest reversible pump/turbines operating in the United States. The pump/turbines could generate and pump at a record-high hydraulic head and unit operating speed.

From the end World War II until the mid-1960s, Colorado's system load had increased by more than six-fold. Capacity additions, for the most part, had involved base load units throughout this period. Recognizing that peaking capacity would markedly improve the load factor on efficient base load units, the company embarked on the installation of Cabin Creek.

The plant, located about 35 miles west of Denver, is situated south of Georgetown, Colo., with the powerhouse and lower reservoir at 10,000 feet elevation and the upper reservoir at 11,200 feet. The steep elevation change between the upper and lower reservoirs formed a significant difference in height between the water source and outflow creating what is known as a high head and making it ideal for a pumped storage project. Plus, it was close to a major load concentration of the Denver metro area and an established transmission line. The steep sides of the valley also permitted the reservoirs to be connected by a tunnel of only 4,300 feet in length, relatively short for the high head and large capacity.

The unique location also had its challenges, though. The icing conditions created by severe winter temperatures at the 10,000 and 11,000-foot altitudes required special attention in design of the facility. The engineering team allowed for 2.5 feet of ice on the surface of both reservoirs and a minimum of 20 feet of water was provided over the tunnel inlet/outlet structure.

In addition, the electrical design of the substation required the analysis of special problems related to the selection of proper materials and equipment to meet the unusual environmental conditions. The 13.8/230-kv step-up transformers had high altitude bushing rated at 825-KV BIL, substantially higher than would be required at lower altitudes. Protection of the transformers required the use of station-type high altitude lightning arrestors. Transient analyzer studies were conducted to determine proper ratings for switching surges.

At the time of commissioning, the plant was extremely innovative and even won the Edison Electric Institute's highest honor, the Edison Award, in 1968. However, in the nearly 50 years since, not much has changed at the plant so the necessity for upgrades is reaching a critical point.

Plant Operations Then and Now

Cabin Creek today consists of two generators with a capacity of 162 MW each, totaling 324 MW. Cabin Creek generates electricity by releasing water from an upper reservoir through a tunnel, which turns the turbine generators. The water is then stored in a lower reservoir. The upper reservoir has 1,192 feet of head that equals a pressure of approximately 550 psi. At full load, this equates to about four hours of running time. The lower reservoir has 1,977 acre-feet of usable water and is considered empty at 9,974, at which point there is still 45 feet of water. The upper reservoir may change during normal daily operation from 11,194 feet to 11,140 feet, and the lower reservoir may change from 9,979 feet to 10,007 feet.

During off peak hours at night when customers' electricity use is low, water is pumped back to the upper reservoir and stored when there is less energy demand or when wind generation is available. In that manner, it operates much like a giant battery that Xcel Energy can tap when it is needed most. With more variable energy resources like wind being added to the system, Cabin Creek's energy storage benefits to reduce wind curtailments and the cycling of coal and natural gas resources are valuable in balancing the system requirements. The units can quickly be dispatched to pump mode, which adds load to offset excess generation and helps the maintain energy balance.

Cabin Creek is routinely used to meet a significant portion of Xcel Energy's operating reserve requirements in Colorado. In addition to providing power to balance the energy mix/daily peaking, Cabin Creek is often used as an emergency reserve facility. It can balance the energy system when there are fluctuations in wind energy availability or serve as a reserve when customers' energy demand is high. While in pump mode, Cabin Creek provides non-spinning reserve (responsive load that is off-line but can be fully responsive within 30 minutes or less).

Each generator can go from complete stop to fully loaded in 10 minutes or less, making it essential for peak demand times and emergency situations. Cabin Creek is also unique in its ability to 'black start.'

Cabin Creek can start up with only the use of station batteries in an emergency situation. The team tests black start procedures once a year and participates in annual drills with local emergency responders. It can also start the Georgetown hydroelectric plant without external power and feed Cabin Creek. The station batteries last about 4 hours.

In addition to controlling its own operations, using the same switchboard that was used in 1967; Cabin Creek operates all remaining five Xcel Energy's Colorado hydro plants. Its control room is manned 24-hours a day, 365 days a year.

Its role in peak generation, emergency backup, and operation controls make it critical to the future of Xcel Energy's energy balance and reliable generation requirements. Plus, as customers push for more and more renewable energy sources and options, Cabin Creek will remain a vital asset to balance variable wind resource and provide additional renewable generation.

The Necessity for Upgrades

Now that the facility is nearly 50 years old, it is reaching the end of its useful life. The age and condition of the equipment are such that it needs major refurbishments to continue operating reliably.

In May 2015, Xcel Energy filed a plan with the Colorado Public Utilities Commission (PUC) to upgrade Cabin Creek to increase the capacity and extend the life of the pumped storage hydro facility. The utility requested approval to spend approximately $88 million on a 5-year refurbishment project.

The project includes upgrading the two pump-turbine units by 36 MW, or the equivalent of the electricity needed to power approximately 27,000 homes, to a total of 360 MW. It also includes increasing the size of the upper reservoir by installing a parapet wall – an upward extension of the dam – that would provide an additional 75 acre-feet of water storage capacity.

The upgrade project will replace the runners (water wheels) with upgraded designs, improve the hydraulic flow through the inlet gates, raise the level of water that can safely be contained in the upper reservoir, refurbish or replace the remaining generation components to a like-for-like state, and improve the roundtrip efficiency. The refurbished facility will be designed to pump and generate more efficiently, finding the ideal balance between pumping the upper reservoir more quickly for a faster turnaround and maximum generation. Given the unique location and high altitude, Xcel Energy will work closely with contractors familiar with the environment and with extensive experience working on both the electrical and mechanical side of hydroelectric operations in order to meet its rigorous safety, budget, and timing goals.

The project is anticipated to take 60 months to complete, planning to come online in early 2020. Given the emergency and peak demand functions of the plant, the team will take one unit out of service at a time over a 9 month period to enable ongoing operations during construction. With one unit, the plant will still be able to black start if necessary and can generate 75 MW base load running for approximately 14 hours.

In addition, the upgrades will include modernizing the control system. It currently uses some of the same switches installed in 1967 to control Cabin Creek. With the upgrades, it will move to data-controlled systems, which will increase efficiency and decrease the potential for operator error. Similar to the generator unit replacement process, the controls will be upgraded one at a time to minimize any disruptions.

These upgrades will extend the life of Cabin Creek by making smart investments to modernize the plant, leading to efficiency improvements, expanded storage capacity, and increased size of the upper reservoir. The Federal Energy Regulatory Commission (FERC) issued a license renewal for continued facility operations, predicated on the construction upgrades, which will allow Xcel Energy to operate the hydro facility for at least another 40 years.

Understanding the importance of this project, the Colorado PUC approved Xcel Energy's request soon after filing. It stated the refurbishment was "essential to support reliable, economic service beneficial to customers." Moving forward, Cabin Creek will be able to reliably operate and provide renewable generated energy for decades to come. The approved upgrades expand the utility's portfolio of renewable energy sources and ability to develop new programs to give customers more choices in the energy they use.

About the author

Bruce Cotie is a plant manager with Xcel Energy, where he oversees nine generation plants across the Public Service of Colorado operating company's service territory. After a career in the Navy assigned to the machinery division on a nuclear powered submarine, he has 12 years of operating and maintenance experience with Xcel Energy in the areas of coal-fired generation, combustion turbines and wind farm facilities.

THE BIGGER PICTURE

BY JOHN GILLERMAN

SGIP's OpenFMB™ spreads power-system insight to grid-edge devices

Did you happen to see the *New York Times* story about TXU Energy's free-nights-and-weekends rate plan? The Lone Star State generates 10 percent of its power from wind turbines and accounts for some 23 percent of the nation's total wind capacity. But, since the wind comes up about the same time most people are bedding down for the night, TXU is trying to use rates to shift consumption to leverage all that inexpensive wind power it has whipping around the state.

Imagine the grid consequences of that much generation from an intermittent renewable resource. You still have to provide renewable firming, and you need to manage the power-factor conditions that are created by variable generation. Texas may be largely alone with its grid, but it isn't alone with this problem. And the problem is likely to become much more common, as Distributed Energy Resources (DER) are being deployed with remarkable speed.

One third of new electric capacity added between 2007 and 2014 came from wind installations, and growth should continue at a fast clip for the next few years, according to research from the Lawrence Berkeley National Lab. Energy storage system deployments will go from 62 megawatts in 2014 to 220 megawatts in 2015, and 90 percent is on the utility side of the meter, says GTM research. Meanwhile, a recent report from Navigant Research predicts worldwide installations of microgrid capacity will grow from 866 megawatts in 2014 to more than 4,100 megawatts by 2020. Most of it will go online in North America.

These statistics demonstrate that DER aren't just in our future anymore. They're here, and they're changing the entire landscape of utility automation systems.

With the proliferation of DER and an ever-increasing number of smart-grid components, it's crucial that we push for greater interoperability and system awareness for equipment now populating our grid edge and distribution feeders. That's why the Smart Grid Interoperability Panel (SGIP) has multiple initiatives underway, including one called EnergyIoT™, which takes a holistic view of utility connectivity to behind-the-meter devices, utility enterprise systems and grid operations in light of the Internet of Things (IoT). A subset of SGIP's EnergyIoT™ work is the OpenFMB™ project, which is a framework for peer-to-peer messaging for fielded devices and interconnected systems.

OpenFMB teammates from multiple utilities, power-sector vendors and research institutions reached a milestone in early November: They created and presented a live demonstration of the OpenFMB framework in operation in a simulated microgrid. The display also will be available to attendees of next year's DistribuTECH conference slated for Feb. 9-11, 2016 in Orlando, Fla.

OpenFMB team at SGIP 2015 Annual Conference

Interoperability matters

Phase one of the OpenFMB working group's activities has been focused on the interplay between multiple systems, such as those associated with microgrids and the grid as a whole or smart substations serving distribution feeders. Sure, grid automation is nothing new, but the proliferation of DER and intelligent systems is adding a new twist to it.

The exponential growth of smart substations and grid-edge devices is making centralized intelligence less necessary and centralized control unmanageable. Sending sensor and measurement data back to the control center so that some centralized system can decide what a feeder device should do won't be the most efficient way to run the grid once it's jam-packed with automation.

That means we need to push both intelligence and control to the distribution-system and grid-edge devices themselves. When you do that, those devices will need knowledge from other power-system devices around them. They'll need to know about the status and other information related to power lines and equipment nearby.

Here's an example why: Suppose you have a feeder automation device – a capacitor, a load tap changer or some other piece of equipment – and it's connected to a bunch of smart meters at people's houses. Those smart meters can relay voltage information from each endpoint, and the feeder automation device can help you keep voltage steady. But, there's a problem. The way the distribution system is constructed, when you install the feeder automation device, you don't actually know which meters you're connected to because electro-connectivity can change when distribution switching happens.

So how does a feeder automation device make use of measurements from meters if it doesn't know which meters it's connected to? In order to attach meter information to feeder information, it has to go all the way back to the control center and wait for a control signal because the distribution management system or GIS has a network model.

Under that approach, if part of your communications network is degraded or overloaded due to something such as a storm, all of a sudden you have compromised the resiliency of the system as a whole. You have essentially a single point of failure – the GIS or distribution management system – if you're always relying on such software to provide all the intelligence of the grid.

Here's where OpenFMB comes in: We're pushing power system information into the field so that the devices can make intelligent decisions, either individually or in cooperation with other devices. Like the DNP3 and IEC 61850 protocols that exchange device information, the OpenFMB methodology leverages common information model (CIM) messaging about the electrical network to give devices insight into the power system as a whole. Unlike previous, point-to-point communication, the OpenFMB approach uses a publish/subscribe paradigm. In this paradigm, data sources publish their information once, and every device that subscribes to that data and has permissions receives that data.

Helping the players play nice

The result of this approach is more highly defined intelligence for the many players out on a smart distribution grid, as well as a unified way of communicating across a system of interconnected sub-systems.

This was apparent in the live demonstration at SGIP's 2015 annual conference in New Orleans early in November. There, the OpenFMB team showed different microgrid devices publishing information to the bus and all interested devices receiving that data, including the microgrid controller. Elements of the microgrid included simulated load, two generators, a solar installation and a recloser for islanding. In order for such local devices to make intelligent decisions, they need to exchange status information related to the grid and device operations. The field message bus that gives OpenFMB its name facilitates interchange of data and use of CIM-based system information.

At the end of the day, this demonstration showed that multiple vendors with disparate device types can interact and easily communicate. This opens up a number of promising developments for grid modernization efforts.

The OpenFMB approach can enable legacy equipment to be retrofitted for new capabilities and extended life with OpenFMB adapters. This allows grid devices, such as meters, relays, inverters and cap bank controllers, to speak to each other. Because it connects previously siloed domains, it facilities data integration, supports decentralized intelligence and reduces data latency issues while helping utilities manage local grids efficiently based on local resources and conditions. Bottom line: OpenFMB will help utilities put solutions right next to the problems that will hit our distribution lines as DERs proliferate.

If you attend DistribuTECH next February, be sure to see the OpenFMB demonstration for yourself. It will show you how the diverse universe of players in the smart grid can more easily interconnect. And, like TXU Energy's nighttime electricity, it's free.

ABOUT THE AUTHOR

John Gillerman is a business and integration architect with in depth experience in data governance, information modeling, middleware, and process management systems. His focus is on the integration of real-time and business applications, and he brings world class experience for implementing and integrating OT systems using utility industry standards and protocols.

SECURITY SESSIONS

It's time to take a serious look at substation cybersecurity

Cybersecurity is well understood by information technology (IT) professionals. Many IT security experts have years of experience in securing their computers and networks from hackers and other threats. They know what hardware, software and processes they should have in place to protect their companies' information.

Unfortunately, cybersecurity isn't as well understood in the utility industry. The operational technology used in substations – the automation and control systems that monitor critical infrastructure – tends to use proprietary techniques for handling device security. This makes it difficult for utilities to get a holistic view of their substation cybersecurity.

Getting a more complete view of substation cybersecurity should be a top priority for utilities. According to the U.S. Department of Homeland Security, 53 per cent of the cybersecurity incidents reported to the agency in the first half of 2013 involved the energy industry. And next April, the North American Electricity Reliability Corp.'s Critical Infrastructure Protection (NERC CIP) standards Version 5 will go into effect. At its core, the NERC CIP standards are designed to protect the cyber assets utilities rely on to operate their electrical networks. Unlike past NERC CIP standards, Version 5 will encompass all cyber assets that could affect the bulk electric system, which means operators must significantly expand their cybersecurity coverage.

This means Canadian utilities need to upgrade their cybersecurity frameworks. This encompasses not only products, but processes and people as well. Ensuring every employee involved in substation operations follows security rules and procedures is as important as having the correct technology in place.

Products

Over the last several years, power networks have become simpler to manage as a result of better connectivity in devices connected to the networks. Employees can monitor, manage and troubleshoot more devices remotely, saving utilities time and money. However, any device connected to a network is inherently more vulnerable to cyberattacks, even if that device isn't connected directly to the Internet. All it takes is for one device on a network to have an Internet connection to put the whole network at risk.

Unlike IT security products, operational technologies used by power operators often do not have security monitoring or standards built into them. Some security vendors have tried to solve this issue with built-on solutions, keeping the security layer separate from the devices. But this is not ideal because if the security layer is breached, every non-secure device behind that layer becomes vulnerable.

Instead, utilities should be implementing products with security built in. Products based on international security standards – such as IEC 62351 and IEEE 1686 – are ideal, a proven certification is a recognition of such implementation.

Some of the features products should have include:

- Support for unique user names – many devices used in substations today feature accounts that are shared among multiple users. This makes it much more difficult to trace a security issue back to a particular user or account if a problem arises.

- Security logging – devices should be able to identify the people who are authorized to perform particular actions. They should also be able to record "security events", such as the creation or modification of a password.
- Support for security monitoring – operational technology needs to be monitored centrally to ensure devices remain secure. Staff should be able to monitor devices through the Simple Network Management Protocol (SNMP) used extensively by IT departments to manage IT networks. SNMP alerts will let security administrators know in real time when an abnormal event has occurred.
- Third-party product support – ideally utilities should not be locked into purchasing products from any particular operational technology vendor. This ensures utility staff will always be able to implement the best technology for a particular job and still be able to manage and control it in their existing environment.

Utilities will need to monitor their networks with centralized management and monitoring tools that can receive alerts from any device in the extended substation network. For example, a security administration solution enables staff to manage the configuration and security policy deployment across all substation automation systems from one location. It also allows staff to collect security information and perform audits for all networked devices.

Processes

While having the right technology in place is an important part of any security strategy, creating processes and putting them into practice is just as critical. Every employee needs to be well trained in security procedures and understand the key role security plays in substation operations.

A good first step in creating an effective substation cybersecurity plan is to define policies and make everyone involved in operations – employees, partners, contractors and other users – aware of their obligations to protect the substation's infrastructure. The policies should describe which devices must be protected, define who can access those devices (and how) and give examples of unauthorized actions and the consequences for violating security procedures.

Some examples of what a security policy should include are:

- Lists of control system hardware and software
- Rules for sensitive information and defining who can access it
- Classify devices and what security rules should apply to each classification
- Procedures for what should happen if a cybersecurity incident occurs – for example, who should be notified and what actions should be taken
- A response team that will resolve any cybersecurity incidents that may occur

Once a policy is in place, utilities should review their processes regularly to guarantee they remain effective, because cyberattacks and vulnerabilities evolve over time. Personnel should conduct a security review at least once per year and ensure all systems are patched regularly.

Ideally, staff should establish a patch management system that inventories all hardware and software. As part of the system, administrators should also look for news on vulnerabilities and patches, test patches in a non-production environment to ensure they won't interfere with operations and schedule the deployment of patches to the production hardware and software.

People

Implementing an effective substation cybersecurity system that will meet the new NERC CIP standards requires utilities to train or hire cybersecurity specialists. One option is to train employees who will be capable of working in the field. Another is to manage security from one central location with a pool of security experts capable of working through complex, cross-disciplinary events.

Because substation systems are so complex, cross-disciplinary coordination is important. Engineers, IT administrators and security staff need to communicate well and work together to identify potential risks and attacks. Utilities should put systems in place that encourage cross-disciplinary cooperation and planning to improve their security preparedness.

Utilities should also ensure they work closely with third-party partners who understand the evolving security landscape and can help keep substation security policies and technology up-to-date. Security partners should have a solid understanding of all the systems involved in substation operations, how they interact with one another and how they can be secured with an in-depth defence. They should also be knowledgeable about cybersecurity regulations and security standards. And finally, they should be capable of creating customized solutions for their customers that work with equipment from multiple security vendors.

Unfortunately, there is no one-size-fits-all solution to substation security. Every substation network is unique and will have different equipment and requirements. But by upgrading hardware and software technologies, carefully crafting comprehensive security policies and procedures and putting in place well-trained security staff, utilities can minimize their risk of cyberattack while ensuring they meet the new NERC CIP security standards.

ABOUT THE AUTHOR

Eric Deschenes is Vice-President of the Energy Business for Schneider Electric Canada. He has more than 24 years of experience in the Canadian electrical power industry and earned his bachelor's degree in engineering from Ecole Polytechnique University in Montreal.

Guest Editorial

Understanding Dissolved Gas Analysis (DGA) Techniques and Interpretations

By Jeff Golarz

ABSTRACT

The use of Dissolved Gas Analysis (DGA) as a method for determining the types of pending or occurring faults within power transformers has been in practice for many years. It has been proven that the generation of certain gases within a transformer is an excellent indicator that a failure is pending. DGA techniques have become so sensitive and accurate at measuring these gases that the entire scheme has become standard practice as part of the normal maintenance for many electric power utility companies.

Despite how effective DGA techniques have become, the proper use and interpretation of gas level results (i.e., ppm levels) is still not fully understood by many utility people. Therefore, it is the intent of this paper to provide common knowledge and understanding of all the tools, methods, and techniques available for non-chemical engineers within typical utility companies. We will fully describe each of the available interpretation techniques as well as provide a comparison of the accuracy and reliability of each diagnostic method based on one independent case study.

Introduction

Reliable energy flow is essential for all major electric utility companies, making power transformers one of their most important assets and largest investments. In addition, the transformer fleets in several parts of the world are operating beyond their design lives, with higher-than-average loads. For these reasons, transformer condition assessment and failure analysis is a high priority.

Over time, electrical and thermal stresses on a transformer's insulating materials (arcing, corona discharge, sparking, and overheating) can result in incipient transformer faults. As these stresses accumulate, the insulating materials will breakdown and release several different gases. These gases can be detected in transformer insulating oil using sensitive and reliable Dissolved Gas Analysis (DGA) techniques for determining the type of pending or occurring fault.

DGA is considered the best method for determining a transformer's overall condition and is now a universal practice. Advantages of DGA include:

1. Advanced warning of developing faults
2. Status checks on new and repaired units
3. Convenient scheduling of repairs
4. Monitoring of units under potential overload conditions.

The use of appropriate DGA diagnostic methods can provide improved service reliability, avoidance of transformer failure, and deferred capital expenditures for new transformer assets. To ensure success, we will discuss the tools available for DGA and how to properly interpret the results.

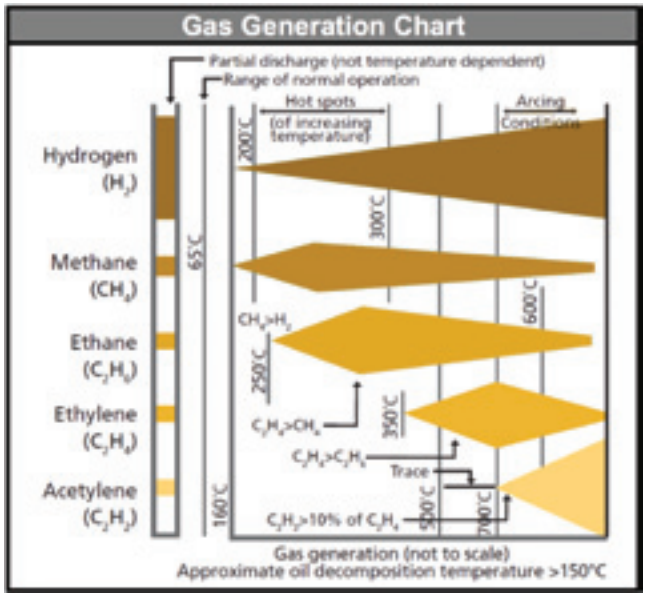
Formation of Gases in Transformer Oil

Thermal and electrical stresses that occur within normal operating transformers generate hydrocarbon gases which can indicate potential problems within the transformer. Some gas generation is expected as transformers age, so it is important to separate normal gassing rates from excessive gassing rates. Since normal gas generation varies with transformer design, loading, and the type of insulating material used, general gassing rates are used for all transformers to define abnormal behavior.

Typical gases that appear in transformers are hydrogen (H_2), methane (CH_4), ethane (C_2H_6), ethylene (C_2H_4), and acetylene (C_2H_2). These gases begin to form at specific temperatures and dissolve within the insulation oil of a power transformer, as shown in Figure 1. The types and quantities of the gases that form will depend on the nature and intensity of the fault.

Understanding Dissolved Gas Analysis (DGA) Techniques and Interpretations

Figure 1



Hydrogen and methane begin to form in small amounts around 150 °C. The production of hydrogen continues to increase as the temperature increases. At about 250 °C, the production of ethane starts. At about 350 °C, the production of ethylene starts. After reaching their maximum points, methane, ethane, and ethylene production goes down as the temperature increases.

Acetylene production begins between 500 and 700 °C. In the past, the presence of only trace amounts of acetylene was considered to indicate a temperature of at least 700 °C had occurred, however, recent discoveries have led to the conclusion that a thermal fault (hot spot) of 500 °C can produce trace amounts (a few ppm). Larger amounts of acetylene can only be produced above 700 °C by internal arcing.

Between 200 and 300 °C, the production of methane exceeds that of hydrogen. Starting at about 275 °C and up, the production of ethane exceeds that of methane. At about 450 °C, hydrogen production exceeds all other gases until about 750 to 800 °C, at which point a larger amount of acetylene is produced.

Thermal decomposition of cellulose materials will also begin at about 100 °C or less and produce carbon monoxide (CO), carbon dioxide (CO_2), hydrogen (H_2), methane (CH_4), and oxygen (O_2). Therefore it is imperative to operate transformers below 90 °C.

Types of Faults

A proper fault diagnosis will include warnings of any gases with concentrations, increments, rates of change, or ratios that exceed the standard limits, along with short interpretive remarks and recommendations based on the findings. To help identify the different faults when a diagnosis is being made, the following classes have been identified after the physical inspection of hundreds of faulty transformers detectable by visual inspections and DGA results. They are also summarized in Figure 2.

Partial Discharge (PD) – the corona type occurs, which can result in deposits of 'X-Wax' on paper insulation, or the sparking type occurs, which can induce pinholes (carbonized punctures) in paper that may be difficult to find.

Discharges of Low Energy (D1) – occurs in oil and/or paper, as indicated by large carbonized punctures in paper (pinholes), carbonization of the paper surface (tracking), or carbon particles in oil (as in an LTC).

Discharges of High Energy (D2) – occurs in oil and/or paper, as indicated by extensive destruction and carbonization of paper or metal fusion at the discharge extremes, extensive carbonization in oil, and in some cases, tripping of the equipment confirming a large current follow-through.

Thermal Fault (T1) – occurs in oil and/or paper below 300 °C, turning the paper "brownish".

Thermal Fault (T2) – occurs in oil and/or paper above 300 °C and below 700 °C, carbonizing the paper.

Thermal Fault (T3) – occurs in oil and/or paper above 700 °C with strong evidence of carbonization of the oil, metal coloration (at 800 °C), or metal fusion (below 1,000 °C).

Figure 2

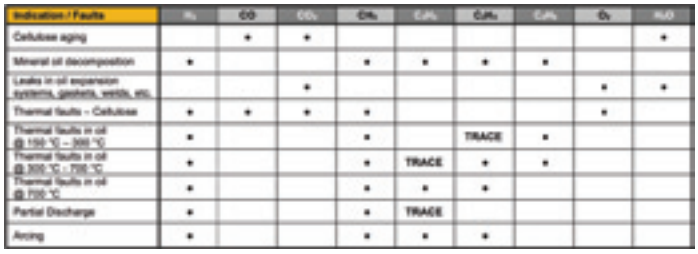
Abbreviations	Descriptions
PD	Partial Discharges
D1	Discharges of Low Energy
D2	Discharges of High Energy
T1	Thermal Fault, t < 300 °C
T2	Thermal Fault, 300 °C < t <700 °C
T3	Thermal Fault, t > 700 °C

Fault Identification by Gas Type

Potential faults such as over-heating, partial discharge, and sustained arcing produce a range of gases. The concentrations and composition of these gases can be used to identify the type and estimate the severity of the fault, as shown in Figure 3. Since all types of faults create a variety of gases and not just one, the diagnostic approaches that detect multiple gases and account for the entire gassing picture often get more accurate results.

Understanding Dissolved Gas Analysis (DGA) Techniques and Interpretations

Figure 3



Indication / Faults	H_2	CO	CO_2	CH_4	C_2H_4	C_2H_6	C_2H_2	O_2	H_2O
Cellulose aging		+	+						+
Mineral oil decomposition	+			+	+	+	+		
Leaks in oil expansion systems, gaskets, welds, etc.			+					+	+
Thermal faults – Cellulose	+	+	+	+				+	
Thermal faults in oil @ 150 °C – 300 °C	+			+		TRACE	+		
Thermal faults in oil @ 300 °C - 700 °C	+			+	TRACE	+	+		
Thermal faults in oil @ 700 °C	+			+	+	+			
Partial Discharge	+			+	TRACE				
Arcing	+			+	+	+			

DGA Diagnostic Tools

Most of the DGA diagnostic tools in use today can be found in the IEEE C57.104 or IEC 60599 guides. Based on these two guides, other national and international guides that include additional tools are also available, but for our purposes we will only discuss those tools found in the IEEE and IEC guides. Figure 4 summarizes the diagnostic tools that we will be discussing, as found in the latest IEEE guide, a recent draft standard (IEEE C57.104- D11d; not approved) of the IEEE guide, and the IEC guide.

Figure 4

Analysis Tool	Reference Standard		
	IEEE C57.104-1991	IEEE PC57.104 D11d	IEC 60599-1999
TCG Procedure	X		
TDCG Procedure	X	X	
Key Gas Method	X	X	
Doernenburg Ratios	X		
Rogers Ratios	X	X	
Basic Gas Ratios (IEC Ratio)			X
Duval Triangle			X
CO_2/CO Ratio		X	X
O_2/N_2 Ratio			X
C_2H_2/H_2 Ratio			X

DGA Diagnostic Tool Selection

There is a wide range of diagnostic tools available for DGA. Some are simpler, using only sums or single ratios of gases, alongside a guideline, to determine different warning levels. Others are more complex, taking multiple gas ratios and fitting them to a precise range of values.

Total Combustible Gas (TCG) procedure and Total Dissolved Combustible Gas (TDCG) procedure are the two diagnostic tools that are non-ratio based. TCG deals with the gases in the gas headspace and TDCG the gases dissolved in oil. They can offer an indication that gas levels are increasing and provide suggested guidelines for operators to perform manual DGA sampling intervals. However, since they do not offer any significant diagnostic value regarding fault type, it is recommended by the IEEE guide to combined them with other diagnostic tools in order to get a better understanding of what is happening in the transformer.

There are three more diagnostic tools that may also be used as a complement to other diagnosis methods for a more accurate assessment of transformer conditions. These are the CO_2/CO ratio, the O_2/N_2 ratio and the C_2H_2/H_2 ratio, as described in further detail below.

CO_2/CO Ratio – this popular ratio is used to detect paper involvement in a fault. If the ratio is below 3, it is a strong indication of a fault in paper, either a hot spot or electrical arcing with a temperature above 200 °C. If the ratio is above 10, it indicates a fault with a temperature below 150 °C. However, this ratio is not very accurate because it is affected by the CO_2 and CO coming from oil oxidation and normal cellulose aging, so with a high quantity of CO_2, seeing a significant change in the CO_2/CO ratio is nearly impossible.

O_2/N_2 Ratio – a decrease of this ratio indicates excessive heating.

C_2H_2/H_2 Ratio – a ratio between 2 and 3 in the main tank indicates contamination by the LTC compartment. In these situations the level of acetylene in the main tank can be quite high, so in order to diagnose true main tank problems, incremental changes in acetylene must be monitored.

The remaining DGA diagnostic tools that we will discuss are considered to be the main interpretation methods used for fault diagnosis of power transformers. This includes the Key Gas, Dornenburg Ratio, Rogers Ratio, IEC Basic Gas Ratio, Duval Triangle, and CIGRE ratio methods. The majority of these methods are ratio-based, meaning they use a subset of the ratios below to diagnose a fault type based on the fit of each ratio result to a specific range of values:

- Ratio 1 (R1) = CH_4/H_2
- Ratio 2 (R2) = C_2H_2/C_2H_4
- Ratio 3 (R3) = C_2H_2/CH_4
- Ratio 4 (R4) = C_2H_6/C_2H_2
- Ratio 5 (R5) = C_2H_4/C_2H_6

It is important to remember that when using ratio-based diagnostic tools, minimum gas levels are required as defined in the guides, for the ratio analysis to be considered valid.

Key Gas Method

The Key Gas method is based on the quantity of fault gases that are released from the insulating oil as the chemical structure breaks at varying temperatures in the transformer. This method uses individual gas levels, or 'key gases,' for detecting faults. Figure 5 summarizes the key gases and their fault indications.

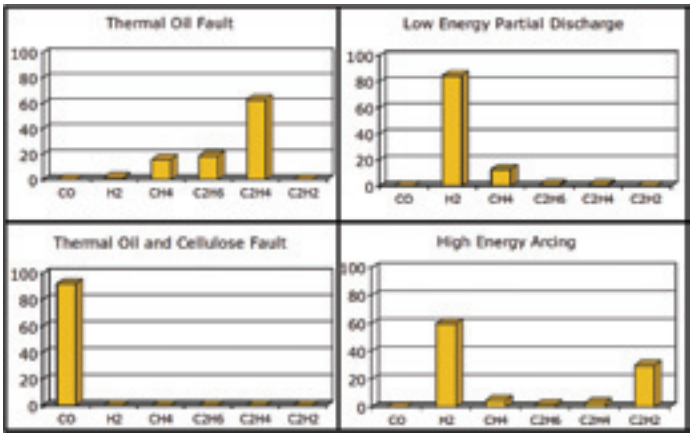
Understanding Dissolved Gas Analysis (DGA) Techniques and Interpretations

Figure 5

Key Gas Method (IEEE Std. C57.104-2008)		
Key Gas	Fault Type	Typical Proportions of Generated Combustible Gases
C_2H_4	Thermal oil	Mainly C_2H_4; Smaller proportions of C_2H_6, CH_4, and H_2; Traces of C_2H_2 at very high fault temperatures
CO	Thermal oil and cellulose	Mainly CO; Much smaller quantities of hydrocarbon; Gases in same proportions as thermal faults in oil alone
H_2	Electrical Low Energy Partial Discharge	Mainly H_2; Small quantities of CH_4; Traces of C_2H_6 and C_2H_4
H_2 & C_2H_2	Electrical High Energy (arcing)	Mainly H_2 and C_2H_2; Minor traces of CH_4, C_2H_6, and C_2H_4; Also CO if cellulose is involved

This method offers diagnostics by calculating the relative proportions (in percent) of the key gases within the transformer. Figure 6 indicates these key gases and their relative proportions to indicate the four general types of faults.

Figure 6



Doernenburg Ratio Method (DRM)

The Doernenburg method can be found in the IEEE C57.104-1991 guide. It has fallen out of favor in some parts of the world due to its complexity and the evolution of it into the Rogers Ratio and Basic Gas Ratios approaches, but compared to other diagnostic methods, the DRM still holds its value as one of the more effective diagnostic tools available.

In order to use the DRM, the concentration of one of the key gases (H_2, C_2H_2, C_2H_4, C_2H_6, or CH_4) needs to be at least double the relevant L1 concentrations, as shown in Figure 7. When this criterion is met, there are four possible ratios that can be calculated if they contain the key gas of concern. Figure 8 shows the proposed fault diagnostics is based on the ranges of the four ratios. The IEEE standard (IEEE C57.104-1991) also has an illustrated step-by-step application of this ratio method for gases extracted from the transformer oil only.

Figure 7

Concentration of Dissolved Gas	
Key Gas	L1 Concentrations (ppm)
Hydrogen (H_2)	100
Methane (CH_4)	120
Carbon Monoxide (CO)	350
Acetylene (C_2H_2)	35
Ethylene (C_2H_4)	50
Ethane (C_2H_6)	65

Figure 8

Ratios for Key Gases – Doernenburg Ratio Method								
Suggested Fault Diagnosis	Ratio 1 (R1) CH_4/H_2		Ratio 2 (R2) C_2H_2/C_2H_4		Ratio 3 (R3) C_2H_2/CH_4		Ratio 4 (R4) C_2H_6/C_2H_2	
	Oil	Gas space	Oil	Gas space	Oil	Gas space	Oil	Gas space
Thermal Decomposition	>1.0	>0.1	<0.75	<1.0	<0.3	<0.1	>0.4	>0.2
Corona (Low Intensity PD)	<0.1	<0.01	Not Significant		<0.3	<0.1	>0.4	>0.2
Arching (High Intensity PD)	>0.1 <1	>0.01 <0.1	>0.75	>1.0	>0.3	>0.1	<0.4	<0.2

Rogers Ratio Method (RRM)

The Rogers Ratio method evolved from the Doernenburg method and is used exactly the same way, but instead of needing significant concentrations of the key gases, the RRM can be used when the concentrations exceed the values listed in Figure 7 (rather than double).

Values for the three gas ratios, corresponding to suggested diagnostic cases, are shown in Figure 9. The fault types (cases) that are provided have been chosen by combining some cases from the number of fault types originally suggested by Rogers.

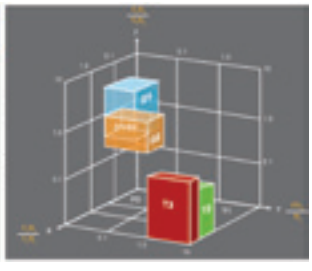
Figure 9

Ratios for Key Gases – Rogers Ratios Method				
Case	Ratio 2 (R2) C_2H_2/C_2H_4	Ratio 1 (R1) CH_4/H_2	Ratio 3 (R3) C_2H_6/C_2H_6	Suggested Fault Type
0	<0.01	<0.1	<1.0	Normal
1	≥1.0	≥0.1, <0.5	≥1.0	Discharge of low energy
2	≥0.6, <3.0	≥0.1, <1.0	≥2.0	Discharge of high energy
3	<0.01	≥1.0	<1.0	Thermal fault, low temp <300 °C
4	<0.1	≥1.0	≥1.0, <4.0	Thermal fault, <700 °C
5	<0.2	≥1.0	≥4.0	Thermal fault, >700 °C

Despite having better accuracy, the Doernenburg Ratio, Rogers Ratio, and Basic Gas Ratio approaches have one drawback where some combinations of gases do not fit into the specified range of values when calculated and the fault type cannot be determined. To further demonstrate this, Figure 10 shows a three-dimensional view of the Basic Gas Ratio (IEC 60599-2007-05).

Figure 10

Case	Characteristic Fault	$\frac{C_2H_2}{C_2H_4}$	$\frac{CH_4}{H_2}$	$\frac{C_2H_4}{C_2H_6}$
PD	Partial discharges	NS	< 0.1	< 0.2
D1	Discharges of low energy	> 1	0.1 – 0.5	> 1
D2	Discharges of high energy	0.6 – 2.5	0.1 – 1	> 2
T1	Thermal fault t < 300 °C	NS	NS	< 1
T2	Thermal fault 300 °C < t < 700 °C	< 0.1	> 1	1 – 4
T3	Thermal fault t > 700 °C	< 0.2	> 1	> 4



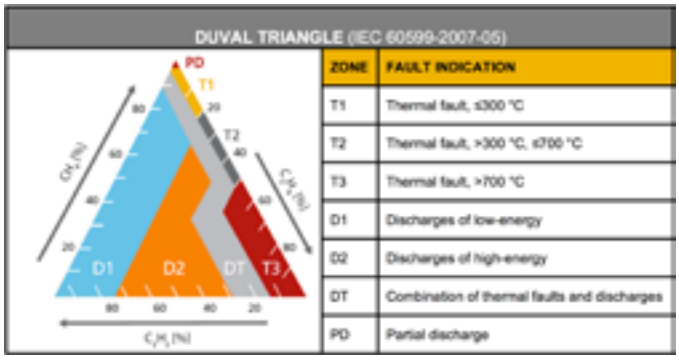
Duval Triangle Method (DTM)

The Duval Triangle method was developed from IEC TC10 databases and an existing IEC 60599 Ratio method. Approximately 200 plus inspected fault cases in service were used to develop the Triangle. Within the triangle there are six (6) potential fault zones covering partial discharges, electrical faults (arcing high and low energy), and thermal faults (over various temperature ranges), plus a DT zone (mixture of thermal and electrical faults).

The use of the DTM is based upon three key gases (CH_4, C_2H_4, and C_2H_2) that correspond to the increasing energy levels of gas formation, as shown in Figure 11. These gas concentrations are calculated and then plotted along the three sides of a triangle diagram using the following ratios:

- $\%CH_4 = (CH_4/CH_4+C_2H_2) \times 100$
- $\%C_2H_4 = (C_2H_4/CH_4+C2H_4+C_2H_2) \times 100$
- $\%C_2H_2 = (C_2H_2/CH_4+C_2H_4+C_2H_2) \times 100$

Figure 11



As previously stated, one drawback of the gas ratio methods is that some results can fall outside the codes and no diagnostics can be given (unresolved diagnostics). This does not occur with the Duval Triangle method because it is a 'closed system.' It always provides a diagnosis, with a low percentage of wrong diagnoses. In fact, according to some published reports, the DTM provides more accurate and consistent diagnoses than any other method available at this time.

Diagnostic Methods Summary

The most important aspect of DGA diagnostic methods is being able to correctly diagnosis recent or potential faults within a monitored transformer. With that in mind, the main DGA interpretation methods discussed in this paper are summarized in Figure 12 and their accuracy is shown in Figure 13, as evaluated using the IEC data bank of inspected transformer failures and various other reports.

Figure 12

Comparison Among: Key Gas Method (KGM), Doernenburg Ratio Method (DRM), Rogers Ratio Method (RRM), IEC Ratio Method (IRM), and Duval Triangle Method (DTM)

Type	Method	Fault Types	Gases Involved
KGM	Uses individual gas concentrations, easy to implement, very conservative	PD, arcing, overheated oil, overheated cellulose	CO, CO_2, H_2, CH_4, C_2H_4, C_2H_6, C_2H_2
DRM	Uses four gas concentration ratios (CH_4/H_2, C_2H_6/C_2H_2, C_2H_2/CH_4, C_2H_4/C_2H_6) To indicate three fault types, uses specified concentration limits to differentiate between faults	Thermal decomposition, PD, arcing	H_2, CH_4, C_2H_6, C_2H_4, C_2H_2
RRM	Uses three gas concentration ratios (C_2H_2/C_2H_4, CH_4/H_2, C_2H_6/C_2H_2)	PD, arcing, low temperature of thermal fault, thermal <700 °C, thermal >700 °C	H_2, CH_4, C_2H_6, C_2H_4, C_2H_2
IRM	Similar to RRM but excludes the C_2H_6/CH_4 ratio, indicates six fault types, uses specified concentration limits to differentiate between faults	PD, low energy discharge, high energy discharge, thermal faults <300 °C, between 300 and 700 °C, and greater than 700 °C	H_2, CH_4, C_2H_6, C_2H_4, C_2H_2
DTM	Uses triangular map to indicate six faults, does not identify a normal state	PD, low energy discharge, high energy discharge, thermal faults <300 °C, between 300 and 700 °C, and greater than 700 °C	CH_4, C_2H_6, C_2H_4

Figure 13

	% Correct Diagnoses	% Unresolved Diagnoses	% Wrong Diagnoses
KGM	42%	0%	58%
RRM	62%	33%	5%
DRM	71%	26%	3%
IRM	77%	15%	8%
DTM	96%	0%	4%

Conclusion

In this paper we presented the DGA diagnostic tools that have the ability to provide results indicating a specific type of fault that is either present or pending to occur in a transformer. This information can then be used to determine the appropriate course of action for that specific transformer. For example, some faults can be considered less severe than others and the transformer can be allowed to continue operating without immediate action to shut down and remove power.

Understanding the available DGA diagnostic methods can be overwhelming, especially when the various types of techniques are taken into perspective. If, for instance, the only technique used, is to take manual oil samples, send them to an oil laboratory, and then wait for the results and direction from the lab, the various diagnostic tools presented here are not applicable because everything is being determined by the oil laboratory used. However, if the end user wants to analyze the oil samples and get results on their own, then the techniques and methods discussed will need to be fully understood so that they are properly used.

The key objective in DGA of fault gases is to correctly diagnose the fault that is potentially generated. Some diagnostic tools have the ability to perform better than others, so it's important to review the most recent information when incorporating them into DGA procedures.

We have presented and discussed the most common methods for analyzing dissolved gas data to interpret potential fault types, including the Key Gas, Dornenburg Ratio, Rogers Ratio, IEC Ratio, Duval Triangle, and CIGRE methods. Keep in mind that many of these methods may yield conflicting diagnoses for the same oil sample and some results from the ratio methods (Dornenburg, Rogers, and IEC) may be unresolved (no diagnosis). With the Duval Triangle Method, this is not a concern. The two independent studies, as previously described, have shown that the Duval Triangle Method resulted in a 96 percent correct rate of the determination of a transformer fault and although it had a higher percentage of wrong diagnostics than the DRM, it had a lower rate of 0 percent for 'unresolved' diagnostics.

The Future

DGA diagnosis techniques presented thus far use fault gas concentrations or ratios based on the practical experience of various experts, rather than on quantitative evidence. Now, with the availability of extensive DGA data, researchers are motivated to develop an alternative approach to DGA data interpretation alone. These different or alternate approaches include artificial intelligence (AI) techniques, Fuzzy logic, and neural networks techniques.

Recent development of the artificial intelligent (AI) model based on a combination of KGM, DRM, RRM, and DTM techniques shows some future insight, as shown in Figure 14. AI approaches provide more accurate and reliable transformer diagnoses than KGM, DRM, RRM, and DTM alone. However, even though a majority of the AI approaches can diagnose faults with high accuracy, some of them fail to distinguish between thermal faults in oil and the same faults in cellulose, so engineering judgment is still required.

Figure 14

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Jeff Golarz, Director, T&D Solutions & Gas Products with LumaSense Technologies, Inc. Jeff has over 25 years of experience in the design, development, manufacturing, and sales of electronic devices and systems for industrial control equipment and systems. He currently holds the position of Director Business Development T&D Solutions for LumaSense Technologies. He has worked as VP Sales and Marketing Manager, Sr. Product Director, Sales and Marketing Director, Business Development Manager, Program Manager and has been Engineering Manager for various high-tech electronics companies. He most recently held the position of Business Development Manager, ABB Substation Automation Systems. Prior to ABB, Jeff was the Sr. Product Development Manager at BPLG/Serveron responsible for the Transformer DGA monitors and other substation solutions products. He is a member of IEEE, PES, IEE Transformer Standards, and several energy working groups, including CIGRE North America. Jeff has a degree in Mechanical Engineering, a degree in Electronic Control Engineering, and is currently working toward his Master's Degree in Business Administration.

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