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January 2006
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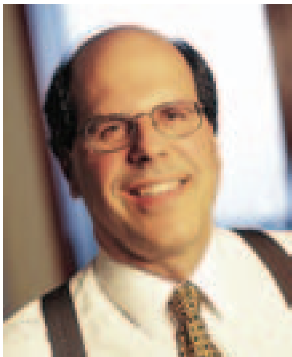
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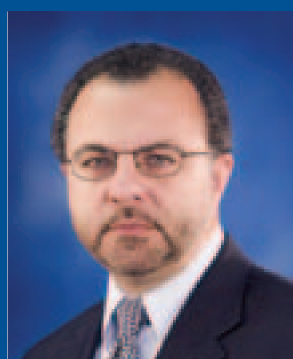
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STANDING AT THE CROSSROADS OF NEW GENERATION

By Don Horne, Editor

A hot, dry summer and frosty winter have placed an increased demand on the grid. The hot and dry factor in the summer was a double-edged sword, as the increase in demand for air conditioning (compounded by lowered water levels for hydro-electric suppliers) ultimately resulted in higher costs for the consumer.

Add to the mix the dramatic increase in natural gas and oil prices.

Natural gas prices jumped 9 per cent, rising by $1.29 (U.S.) to $14.99 per thousand cubic feet on the New York Mercantile Exchange on December 8 - the biggest fluctuation of any commodity in the world that day. The January natural gas futures topped the previous record close, $14.34, which was set on Oct. 25.

But these are not the only pressures being brought to bear on the industry.

On the west coast, the Snohomish County Public Utility District (PUD) abandoned a bid to lower customer power rates by 4 per cent for this year following a federal lawsuit requesting more water for endangered Chinook salmon on the Columbia and Snake rivers.

The water is needed to aid downstream migrating juvenile salmon, says the National Wildlife Federation (NWF). And their pleas are not just words in the wind, as they won a similar lawsuit earlier in the year for the summer migration.

According to the Bonneville Power Administration (BPA), which produces electricity at the dams, such water losses will cost the region 770 average megawatts of energy - enough electricity to power almost all of Seattle for a year.

In hard dollars, that's to $450 million annually in revenue losses, $347 million of which would be passed on to Bonneville's customers. Now, instead of a rate reduction for 2006, PUD customers are looking at an increase.

Tacoma Power faces a potential increase of $17 million in its costs next year; Seattle City Light, which reduced rates earlier this year, also could face higher costs.

The NWF say that Bonneville has "cried wolf" in the past over water-flow requests, pointing to the recent increase

in revenues and a one per cent drop in rates.

But environmental concerns do not stop at minimum water levels.

Advocates of wind power must be accommodating to avian concerns (birds and bats, etc.), being careful not to place these giant wind-generation units near established flight paths and nesting and conservation areas.

With prices for oil and gas rising sharply in recent years, activists in the U.S. and Canada have been campaigning for more financial assistance to help low-income people pay energy bills.

In recent months, the Canadian government unveiled a plan to pay a total of $565 million (Cdn) to low-income families with children and to senior citizens.

In the U.S., advocates for low-income people have argued that $5.1 billion (US) in federal energy help is needed this winter. And that isn't even considering the havoc wrought by hurricanes Rita and Katrina.

In Ontario, the Ontario Power Authority (OPA) has recommended that the province needs to construct a dozen or more nuclear reactors that would replace or refurbish reactors at a cost of $30 or 40 billion. Opponents in Ontario to more nuclear construction point to renewable options like geothermal and biomass generation - the latter drawing criticism from the OPA as being unviable as it is wrong to grow crops specifically for electricity production.

Once the bad boy of electricity generation, it seems coal may be back in fashion.

Nevada Power is considering cheaper coal as an alternative fuel for generating power, but the mere suggestion of building conventional coal-fired plants stirs controversy.

Environmentalists consider traditional coal-fired plants to be the pollution-spewing dinosaurs of the energy industry. But officials from Nevada Power's parent say technology may help allay those same environmentalists' fears.

The senior vice president of Sierra Pacific Resources Roberto Denis has stated that they are "actively pursuing and will pursue building clean, efficient coal power plants".

In this case, clean means coal-fired power plants constructed with the latest in pollutant-stripping technologies (but not integrated gasification combined-cycle projects that convert coal into gas, as they are not commercially viable).

At prices quoted in late December 2005, it cost $2 in coal to generate the same amount of electricity that would require $12 in gas (based on an average for the Southern California border on Dec. 21).

Ironically, by 2010 or 2012 when Nevada is expected to be building a coal-fired plant, such gasification technology will be ready for widespread use.

Previous studies have shown integrated gasification plants to be 25 percent more expensive on a kilowatt hour basis than conventional pulverized-coal plants, but a recent study from GE Energy reveals that the price premium can be reduced to 10 percent.

Another consideration is that the federal government may follow California's lead in restricting use of power from conventional coal-fired power plants.

The California Energy Commission proposed that investor-owned electric utilities in that state be prohibited from entering long-term contracts for power from plants that create more carbon dioxide than natural gas-fired plants.

The net result of all this is simple: more generation is needed now, but a consensus on how that will be achieved seems unattainable.

Perhaps the best answer is to push forward with every option, now, so that each can either thrive or wither when put to the test. Certainly the worst option is to do nothing - and that would usher in a modern day dark age.

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INTEGRATED AM/FM AND GIS FOR AN ELECTRIC DISTRIBUTION SYSTEM

By Tommie Gipson, Chelco Services Inc.

The Choctawatchee Electric Cooperative (Chelco) recently completed digitizing their original paper maps using AutoCAD. This project was completed in house and encompassed 322 drawings at 1:500 and some 1:200 scales.

Integrated software places information at the fingertips of those working in the field.

Chelco is located in the panhandle of Florida and serves 30,000 customers in an 1,800 square mile area. Alabama is on our northern border and the Gulf of Mexico is on the south.

Chelco immediately realized the benefits of electronic maps. By using layers, Chelco could add more information than what was on crowded paper maps. With electronic maps they could add multiple layers for any map feature such as roads or joint use poles. These layers could be assigned different colors to make them more visible. They could also turn layers on and off and see only the map details that were needed. They could easily create copies of the maps and make them available over the internal computer network.

On the old paper system when an area became too populated Chelco would create a new paper map using a smaller scale. With digitized maps it was unnecessary because they could zoom in and out of a map at any scale.

There are many advantages using electronic maps over paper maps. Chelco soon discovered they needed more than just electronic maps. They wanted a tool that could provide them with a system-wide seamless map. Chelco wanted to query the billing data and have the maps zoom into a given location. They wanted to be able to draw a map that could show equipment scheduled for maintenance. And they wanted the ability to trace our circuits and let the maps tell them how many customers a circuit serves. Chelco wanted a true GIS.

THE SEARCH

Chelco evaluated applications working with AutoCAD that tried to combine the individual map files into an integrated GIS. Chelco found the available software products could only do one or two of the tasks and performance was far from acceptable.

They were introduced to Environmental System Research Institute's (ESRI's) ArcInfo and ArcView in a few years ago. It seemed to be the perfect solution to take Chelco beyond electronic maps into the world of GIS. Coverages could be created and maintained in ArcInfo and then viewed by users with ArcView. Instead of individual maps, ArcInfo and ArcView treated our data as one seamless map. Chelco began searching for a third party application designed to work with an electric distribution utility. They were disappointed when Chelco found nothing on the market to fit their needs.

In the spring of 1996 Chelco saw an article in a trade magazine about the very product they needed. The article claimed Utility Automation 2000 (UA2000) had successfully integrated workorder creation and posting, truck maps, billing data, and trouble call. Chelco immediately made arrangements for a demonstration.

At the first demonstration of software developed by UA2000 Chelco knew their search was over. The demonstration was given using an electric distribution cooperative with 38,000 accounts. It could display the entire electric distribution system as a complete seamless map faster than AutoCAD could draw even one of our individual digitized paper maps.

UA2000 had a product working with ESRI's ArcInfo and ArcView that could create and post work orders and field inventories using a Windows based laptop. A laptop could also be used to display truck maps. It interfaced with Chelco's billing software allowing daily updates of any changes to the maps or to the billing data. It could interface with any SCADA system they might establish. It provided a trouble call application with automated phone answering. It had an easy-to-use interface to replace the paper truck maps for use in the field. It met and exceeded all of the search criteria and performance specifications.

ROLLING UP OUR SLEEVES

By the summer of 1996 Chelco entered into an agreement with UA2000 to convert their existing electronic maps into ArcInfo coverage's and provide them

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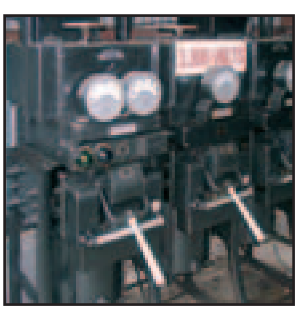

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GIS

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with all of the software tools needed to realize true GIS capabilities. They provided UA2000 with a sample of their billing data and all of the electronic maps from AutoCAD. After sending the maps to UA2000 Chelco kept paper copies of all new work orders to be posted to the new ArcInfo system once they received delivery from UA2000.

Chelco brought the new system on line in the fall of 1997. ArcInfo is the core of the system. Each night it runs an overnight process that has proven to be stable and efficient. In the overnight process ArcInfo gets any as built work orders from engineering and automatically posts them to the system. It gets the latest billing data from their billing software and updates both the maps and the automated phone answering system for trouble call. It runs an integrity check on all of the data and generates an error log each night. The error log is checked the next day by the mapping department to make any necessary corrections such as billing data that has no corresponding map data. The mapping department can also visually see any line sections that may have been accidentally opened from a source feed and corrects the problem. Each night the overnight process then transfers all of the updated information back to our Local Area Network (LAN).

The Mapping and Dispatch Departments were the first to begin using the new software. Chelco's mapping department began the labor-intensive task of posting all of the work orders held during the conversion process. New subdivisions and work plans were also posted to the new system. Our dispatchers were given training in the new system and quickly began realizing the benefits of keying in an account and not only seeing where the account is located, but also the ability to zoom out and see the substation feeding the account. All of the billing data is available with one mouse click on the map. And there were no longer restrictions from the old map boundaries.

Next the engineering personnel were given laptop computers. The laptops were Pentium 166 with 16 Megs of ram. ArcView was loaded along with UA2000's application with new software tools to make their jobs faster and more efficient. The staking engineers were given training on the new system and encouraged to create test work orders. Chelco's plant inventory can now be maintained with each new work order generated. As built jobs are now posted to the maps each night and available to the rest of the company the next day. Engineers can access demand and usage information on an account from their laptops while in the field.

The engineering department can

now generate special maps to help in design and planning. One of the first projects was a cable-aging map for underground cable. Underground cable is color-coded based on age to help schedule replacement. Maps of only three phase lines can be drawn to look for potential tie lines. Maps of conductors or transformers meeting certain criteria can now be generated in seconds. We no longer have to maintain two set of maps (planning and detail maps). Because our maps are true seamless maps (the old detail map boundaries no longer exist) any project can be viewed in its entirety and printed or plotted.

When Chelco issued laptops to our operation department we increased the ram to 32 Megs. They offered voluntary training and had 100 percent attendance during the first two months of training. There were mixed reactions to the new maps in the beginning. After training and using this new tool most of operations were happy with the change. It was easy to see how much the new computer maps would help them in their jobs. On the old paper maps a dense area could take several minutes to locate the account needed. Now any account is located and shown as soon as it is keyed in the computer.

The old paper truck maps might go as long as two years before being updated. Now the maps can be updated daily by logging on to the LAN and transferring the latest version of the maps complete with billing data. Tracing can be done on the laptops both upstream and downstream. Upstream tracing can be used to show the source feed at any point on the system. Downstream tracing will show all of the consumers fed beyond the selected point along with the total connected kva and the number of transformers. The longest circuit takes 10 to 15 seconds to trace and the smaller circuits are almost instantaneous.

The marketing department can now create maps of the entire system from select queries such as kwh greater than a certain value. They can quickly generate a map showing all of our demand accounts color-coded by size. On of the first maps generated was a system-wide map of all 30,000 customers to visually see density patterns on the system. The system can generate any of these maps in seconds and then plot them.

CONCLUSION

Chelco have successfully integrated AM/FM with GIS. The maps are dynamic and the entire company is able to take advantage of the most recent map and billing data. The truck map software is easy to use and fast. The combined size of all of our old AutoCAD drawings was 920 megabytes. The same data takes up less than 90 megabytes in ArcInfo and ArcView. When zipped the size is 40 megabytes for use in data transfers from the LAN.

Trouble calls are handled more efficiently by both dispatch and operations. Knowledge about our system that was previously unavailable can be readily accessed. We now have the ability to bring GPS and SCADA data to our maps when it is decided to implement them. Creating, processing, and posting work orders has brought the potential to rethink the way business is done by streamlining and becoming more efficient.

ESRI has made ArcExplorer available from their web site and some of Chelco's employees use this software for viewing the system map. Every employee now has access to our GIS. They are considering publishing some of the data over the Internet to be viewed with ArcExplorer. The potential for new ways of using our valuable data is now unlimited because of our integrated GIS.

The new integrated GIS has impacted every department in a positive way. They have found the "Holy Grail" of GIS for an electric distribution system.

SCADA DEPLOYMENT USING OBJECT LINKING AND EMBEDDING PROCESS CONTROL

By Randy Kondor, Matrikon

SCADA deployment can effectively use OPC (or OLE, object linking and embedding process control) provided that the driver's SCADA engine properly handles the unique SCADA communication requirements. Traditionally, SCADA (Supervisory Control and Data Acquisition) deployment has always used proprietary software applications and drivers to enable control centers to effectively manage the large amount of data collected. With the introduction of OPC, there have been various attempts at applying industrial standards to these SCADA based implementations. To help these attempts succeed and avoid significant cost overruns, integrators must differentiate between "plant-based" OPC mentality and SCADA applications.

SCADA IS DIFFERENT FROM MANUFACTURING

Manufacturing plants are typically confined to a small geographical area, and are usually less than a square mile. This includes businesses such as Pulp & Paper, Petrochemicals, Refineries, Automotive, etc. Their communication methods normally use reliable Ethernet or serial mediums, and frequently use a DCS (Data Control System) and/or PLCs (Programmable Logic Controllers) to control their process. In sharp contrast, SCADA applications cover very large geographical regions, frequently measured in the hundreds or thousands of square miles. These enterprises include: pipelines, oil gathering fields, electrical transmission utilities, water/wastewater, etc. As a result, they usually prefer satellite, radio, or modem communication, and typically rely on RTUs for their control. From a driver perspective, the biggest difference between Plant and SCADA implementations is the communication. (While hybrid plants exist, we only cover the pure SCADA concepts, which can then be easily transferred to hybrid plants.)

Due to their confined geographical nature, Manufacturing Plants typically use a robust and reliable Ethernet backbone, which are usually installed in electrically quiet (i.e. little noise) locations. Bandwidth, from 9600 bps to Gigabit networks, is plentiful. They are also able to use a relatively small number of PLCs and DCSs, as the wires can economically reach all the necessary equipment, sensors, actuators, etc. On the other hand, due to their large coverage area, SCADA enterprises rely on noisy telemetry (wireless) or telephone (leased) line communication. Consequently, they also use lower communication speeds (300 – 9600 bps), and a very large number of RTUs, frequently numbering in the hundreds or even thousands.

OPC Servers for SCADA applications must take these factors into account. They must optimize their communication to allow for extra noise, low bandwidth and a large device count. They must also handle their priority of operations differently than in a plant. Finally, the SCADA Master (the OPC Client application) must behave slightly differently to help the OPC server behave properly.

> Low Bandwidth communication plagues SCADA operations. Unlike in Plants, SCADA bandwidth is at a premium.

NOISY COMMUNICATION

Noisy communication is the hallmark of SCADA operations. Invalid packets are very common, and extra bits often slip into the packets due to radio squelch. It is important for SCADA servers to differentiate between an invalid data packet as indicated by a bad CRC (Cyclic Redundancy Check), and packets that are invalid due to radio squelch. In the former, the read must be performed again. But, if the SCADA server recognizes the latter (extra bits after a good CRC is detected), it can easily clean up the data by simply ignoring the extra bits. This data cleansing enables the SCADA server to avoid extra reads where they are not required, and save on precious bandwidth. OPC enables the servers to have a dynamically configurable number of retries. Users can specify the number of retries that are acceptable in their specific situations.

LARGE RTU COUNT

A large number of RTUs (Radio Transmission Units) is also a signature aspect of SCADA applications. While plant-based drivers rarely connect to more than a few PLCs simultaneously, SCADA servers frequently connect to tens or even hundreds or RTUs. SCADA servers must usually share a single connection amongst many RTUs, resulting in a connect-read-disconnect operation. SCADA server must be very efficient in their connection and disconnection procedures. As well, they must adhere to a dynamic polling sequence that enables them to read data from all the devices in a round-robin polling sequence, and also be able to interrupt the sequence with a higher priority write operation. Once the interruption is complete, the SCADA server must resume its regularly scheduled polling sequence. OPC uses a timestamp to indicate the last time that a given value was read. This enables users to easily tell if they should interrupt the polling sequence to refresh their data, or if their data is at an acceptable age. This reduces the number of interruptions to the SCADA server, and reduces system load.

LOW BANDWIDTH

Low Bandwidth communication

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FREE ALL WISCONSIN UTILITIES TO MAKE MONEY HELPING CUSTOMERS SAVE ENERGY

By Stephen Heins, VP of Corporate Communication, Orion Energy Systems

Why does Wisconsin continue to reward electrical consumption, generation and marginally competitive solutions in an era when we are in a major construction phase for new power plants and transmission infrastructure?

Yes, construction of new power plants and transmission lines may be inevitable, but appropriate deployment of energy efficiency could have an impact, and perhaps even a significant impact, on how many plants are built and how soon Wisconsin will need them. With all that is at stake from an electric rate and environmental perspective, we simply cannot afford to allow current barriers to using our most cost-effective and cleanest solution — energy efficiency — to persist.

Currently, each Investor-Owned Utility (IOU) is allowed to make a return on its fixed-cost investments for each unit of electricity sold, which is 11.5 % per annum. Like any other businesses, the utility's objective is to maximize profits in order to meet its obligation to shareholders. This means they are selling as many kilowatts of electricity to its customer as possible.

In this scenario, the Wisconsin industrial community as the largest users of electricity has the most to lose, because higher electrical costs could make the difference between new job creation and job destruction, between growth and contraction.

Given the fact that the cleanest, least expensive kWh is the one not used and saved for the next customers, why doesn't Wisconsin use the "shared savings" regimen currently being employed by Alliant Energy? This would allow utilities the same return on investment for provable energy efficiencies as they receive for new or existing sources of electricity?

Ultimately, what makes the idea of utility programs for energy efficiency so compelling is that it establishes practical, enforceable rules, whereby large energy efficiencies could be achieved and documented. The potential for such an approach is enormous, because: (1) it is not being done to any extent now; (2) utility programs can help increase market penetration, because they know their industrial customers best; (3) the average Wisconsin industrial customer spend between $40,000 to $60,000 per month, which means each industrial company can potentially save large amounts of electricity; (4) with the opportunity for profit, utilities can now provide the necessary personnel and capital to test new and existing technologies, because they would receive a return on investment for them; and finally, (5) they can provide their business and industrial customers with objective advice about the array of energy efficiencies, helping them identify the most appropriate for each customer.

Not unlike many other states, Wisconsin has accepted the notion that the utilities should not be allowed to administer and implement any conservation efforts, usually for the "fox watching the henhouse" reason. With the advancement of measurement and verification technologies, Wisconsin's utilities can now demonstrate with certainty the amount of energy saved in real time.

The fact is that utilities and regulators need to be able to treat energy efficiency as a supply side option. Then, we can allow utilities to create and manage a portfolio of energy efficiencies not unlike what we have done with renewables. This new approach is a "clean energy portfolio" and it is already being used in one form or another in Vermont, Pennsylvania, Nevada, Oregon and California.

The six most important conditions for achieving the maximum amount of energy efficiency in Wisconsin's energy future are:

1. Energy Efficiency must be measurable, verifiable and sustainable.
2. Utilities should earn a Rate of Return on Energy Efficiency. Treat Energy Efficiency as a supply side resource acquisition.
3. Energy Efficiency should be target based, incorporating load growth, and part of the supply side resource portfolio.
4. Energy Efficiency should provide for participation by all customer classes.
5. There should be no means test on project ROI.
6. Energy Efficiency and Demand response should be incorporated in all future resource requirements.

The major point is that energy efficiency in the commercial/industrial sector is an economic development issue, whereby Wisconsin can make our manufacturing and service economy more competitive. Energy efficiency is not a social program or corporate welfare; it is an economic imperative. With that in mind, it seems eminently practical to align Wisconsin's utilities interest with the Public Service Commission, ratepayers and the commercial & industrial community. Wisconsin needs to creates incentives for all of its utilities to help their commercial and industrial customers save energy.

OPC

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plagues SCADA operations. Unlike in Plants, SCADA bandwidth is at a premium. Due to telephone and telemetry limitations such as distance, weather, radio noise, and other conditions, bandwidth usually remains at a meager 300bps to 9600bps. Communication between the SCADA Master and the associated RTUs must be reduced to minimum levels. It is extremely important that the OPC Server be able to differentiate between the two OPC read types: cache and device read requests. A “cache read” enable the SCADA Master to read the data in the OPC Server’s existing buffer. Cache reads are used in slow processes where the absolute latest values are not required. The advantage is a very fast response from the OPC server, and causes no polling sequence interruption of the RTUs. To get the latest values from the RTU, the SCADA Master must issue a “device read.” A device read causes the OPC Server to stop its regular round-robin polling sequence, and retrieve data from the selected RTU. The advantage of a “device read” is that it provides the most recent values, however, it takes more time to execute, and slows down the entire system’s performance. Thus, the differentiation between cache and device reads will save the SCADA system from resource-hogging reads. This difference also enables the OPC server to implement priority of operations, which are of interest especially when timely data is required, such as in AGA (American Gas Association) reads.

OPC SERVERS ARE NOT A COMMODITY

Although OPC makes it possible to handle the specific issues posed by SCADA operations, the actual feature implementation is left up to the software developers, so it naturally follows that OPC SCADA servers are not created equal. Sophisticated buyers will research their requirements, and ask for them explicitly. Unfortunately, OPC servers that work well in a plant environment do not necessarily work well in SCADA applications. For instance, a simple search on the Internet will reveal many OPC servers that support the popular Modbus protocol; but only a small percentage actually supports Modbus for use in SCADA. Some vendors even offer separate OPC servers for plant and SCADA purposes, so check with your OPC vendor to ensure you are getting what you require.

Thus, OPC and SCADA can be highly compatible concepts. Integrators must carefully research and plan their projects to be successful. The SCADA applications are more difficult to support than their plant-based cousins, since they require special provisions for low bandwidth and noisy communication with a multitude of devices. But, when these requirements are fulfilled, integrators can effectively deploy OPC servers in a SCADA environment.

Randy Kondor, B.Sc. Eng. CompE, is the OPC Product Manager at Matrikon. Randy is responsible for Matrikon’s OPC business unit which is comprised of over 50 full time employees. Since 1996, Randy has been vastly involved within the OPC industry and a strong supporter of the OPC Foundation.

IESO ISSUES ASSESSMENT OF THE RELIABILITY OF THE ONTARIO ELECTRICITY SYSTEM

Recent additions to Ontario's generating capacity and planned market enhancements in the first half of 2006 contribute to a more positive outlook for Ontario's overall supply adequacy picture over the next 18 months.

The overall outlook for resource availability continues to indicate that for most weeks during the 18-month outlook time frame, there are sufficient resources to meet the present resource requirements, under the normal weather demand scenario. Under extreme weather conditions, the outlook results continue to identify significant reliance on imports in many weeks, to meet resource requirements.

While the overall supply situation appears adequate concerns remain in a number of areas within Ontario, particularly in the Greater Toronto Area (GTA) where the need for new supply and transmission facilities is particularly urgent. It is also critical that more efficient regulatory approvals processes be developed in order to enable timely implementation of the required new generation and transmission facilities.

The Independent Electricity System Operator (IESO) regularly assesses the adequacy and reliability of Ontario's power system. This 18-month outlook provides our assessment of the reliability of the Ontario electricity system from January 2006 to June 2007. The assessment uses the most up to date forecast information and considers experience gained from past operations.

A number of changes are forecast for the Ontario electricity sector to address the risks in the GTA and to implement the provincial government's plan for coal replacement and a transition to cleaner forms of generation. The IESO is monitoring the progress of the inter-related generation, transmission and demand management projects underway and planned and the resulting impact on reliability.

EXPERIENCE GAINED FROM PAST OPERATIONS

There were a number of challenges to maintain reliability of Ontario's bulk power system during the summer of 2005. Soaring temperatures brought significant demand and drought-like conditions limited hydroelectric generation, resulting in a continued strain on the power system.

The IESO relied on extensive use of Emergency Control Actions in order to maintain reliability and avoid power interruptions. Public appeals urging customers to cut back on electricity consumption were issued on 12 separate days, five per cent voltage reductions were implemented across the province on two days in August with two additional voltage reductions implemented in the GTA. This occurred despite good performance and availability of the Ontario generation and transmission facilities and the support from neighbouring markets.

Increased supply brought into service in the fourth quarter of 2005 (515 megawatts from Pickering Unit 1), as well as changes proposed by the IESO to put imports into Ontario on a more secure footing during times of need, should improve the supply-demand situation and help reduce the likelihood of a repeat of the events of the past summer.

A Reliability Demand Response Program similar to those of neighbouring markets is being developed for the summer of 2006 to give more certainty that an IESO request for demand response will be followed and to allow for activation earlier in the list of control actions.

To increase the certainty of capacity and energy availability through day-ahead arrangements, the IESO is working with stakeholders to implement a Day Ahead Commitment Process for the summer of 2006.

In the western GTA, and in central Toronto, transformer load levels were near, and in some cases exceeded their capability in summer 2005. The need for transmission enhancements and new supply to unload these transformers continues to be a priority requirement for the IESO.

Outside the GTA, the transmission system is expected to be adequate to supply demand under the forecast conditions studied in this outlook, with some exceptions. Limitations experienced over the

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IESO

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summer of 2005 in the Windsor area, northward into the Hamilton-Burlington area, and westward from the St. Lawrence transformer station limited the use of available Ontario generation and/or limited imports into the province during hot weather, high-demand periods.

Changes and upgrades are underway, and will improve but not completely relieve the situation for summer 2006.

OTHER CONCERNS

There is a number of growing reliability risks that need to be addressed during this assessment period in order to have timely solutions available.

Toronto currently relies on supply generated outside the city to meet demand. The main transmission paths and related facilities carrying this power into the city are already nearing capacity.

New generation must be installed by the summer of 2008 to address the risk of rotating power cuts to areas of central Toronto during periods of high demand. Increased demand response and conservation efforts will reduce but not eliminate the need for new supply. The IESO is working with the Ontario Power Authority to address the need for new supply in Toronto. But in the absence of a viable, approved plan, timely resolution is at risk. The IESO will continue to work with stakeholders to assess the needs and develop options.

Even with new generation installed by 2008, the risk will again grow to unacceptable levels without new transmission, requiring a third transmission path into Toronto early in the next decade to maintain reliability under extremely hot summer weather conditions.

New supply and transmission is also required in the western GTA to address overloading of transmission facilities supplying the GTA, to meet the forecast growth in demand and to control voltages in the area.

The recently announced Goreway natural gas units in Brampton will substantially reduce the reliability risks in the area but not completely remove them. Transmission facilities and lines serving the area exceeded their long-term emergency capability and the IESO's supply deliverability guidelines in summer 2005. A combination of new generation and transmission enhancements are required to address this. Necessary transmission solutions under discussion are likely to be required to provide time for the development of additional supply projects.

MORE EFFICIENT REGULATORY PROCESSES REQUIRED

The current regulatory approvals process is complex and will impede the installation of new facilities in time to address projected reliability concerns. Given the amount of new supply and transmission enhancements required in such a short period of time, timely regulatory approvals processes are required. Serious consideration needs to be given to developing expedited, but thorough, approvals processes to ensure timely implementation of the new facilities.

DEMAND

Energy demand is expected to be 157.0 terawatt hours (TWh) for 2006, a 1.3 per cent increase over the projected energy demand for 2005 (154.9 TWh). The expected seasonal peak demand for the winter of 2006 is 24,899 MW. The expected seasonal peak for the summer 2006 is forecast to be 25,917 MW.

The following table shows the peak demand forecasts for the seasons covered in the Outlook period.

Season	Normal Weather Peak (MW)	Expected Seasonal Peak (MW)	Extreme Weather Peak (MW)
Winter 2006	24,285	24,899	25,802
Summer 2006	24,232	25,917	27,407
Winter 2007	24,547	25,161	26,088

While extreme weather conditions have a lower probability of occurring, history shows that even seasons with average weather will include periods of extreme weather Prudent planning dictates that the system be capable of operating reliably during extreme weather periods without significant use of emergency control actions.

IPPSA 12TH ANNUAL CONFERENCE & TRADE SHOW March 12-14, 2006

www.ippsa.com

By Evan Bahry, Executive Director, IPPSA

"Rolling the Dice: the politics of the power industry" is the latest conference being put on by the Independent Power Producers Society of Alberta. Running from March 12-14, 2006 in the rocky mountain resort of Banff, Alberta, Canada this year's theme tackles the industry's universal challenge.

Whether it's siting issues, or environmental policy or concern with price, the power industry is faced with some unique constraints. It is also true that these challenges are faced by both regulated and restructured power markets.

While we won't propose to answer these issues over two days, the program features industry leaders from across North America who will review key market developments and provide their perspectives on the conference theme.

Some of our speakers include:

Louise McCarren,
CEO, Western Electricity Coordinating Council;

Greg Melchin,
Minister of Energy, Government of Alberta;

David Goulding,
President, Independent Electricity System Operator (Ontario);

Hal Kvisle,
President and CEO, TransCanada Corporation; and

Gary Holden,
President and CEO Enmax Corporation.

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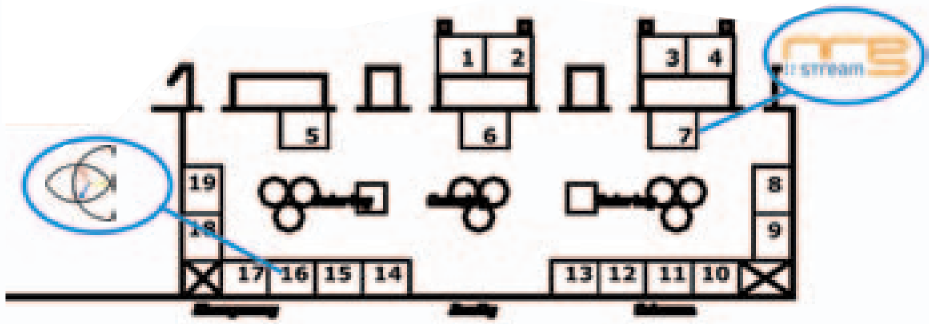

We welcome our more than 500 conference participants, who represent the spectrum of the industry, including generators, consumers, regulators and consultants. They also come from markets as diverse as PJM and the PacNW.

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Montana Alberta Tie Ltd	3
NrgStream	7
The Oxford Princeton Programme	11
Pratt & Whitney Power Systems	14
Trackflow	12
Vision Quest Windelectric	5
ZE Power Group	13

TOMORROW FUND OFFERS A HELPING HAND TO STRESSED-OUT UTILITIES

By Don Horne

The LDC Tomorrow Fund provides money for utility research and innovation.

Ontario's utilities already have their hands full ensuring that the lights stay on and the factories keep humming - so allocating money and resources for innovative research gets pushed to the back of the line.

Cognizant of these realities, the LDC Tomorrow Fund provides funding for research projects and finances energy innovation and opportunities for Local Distribution Companies (LDCs) in the province.

"We were established to enhance the competitiveness of utilities, to fund projects that will show how things can be done better and more effectively, through innovation," says Fund chairman Dave Sinclair, President and CEO of Kenora Hydro.

Funding is available to all LDCs, government agencies, academic institutions and those who work in the electricity industry. Funding decisions are by a board of trustees and administration is conducted by The MEARIE Group.

Criteria for funding are:

- that the applications must be related to the development of commercial opportunities within the electricity market of Ontario;
- projects are expected to be significantly beneficial to the majority of LDCs in Ontario over the short and mid-conditions in the new competitive market;
- projects must represent advancement of technology, procedures, knowledge, and experience; and
- recipients of funding must be prepared to share results and make presentations on the results of the project.

"The projects that are currently in progress are the electrical thermal storage units project, the residential power factor correction project and the broadband-over-powerline for smart metering project," says Mr. Sinclair.

The thermal storage project is being carried out by Peterborough Distribution Inc., with Whitby Hydro working on the residential power factor correction project.

"The thermal storage units - like the residential correction project - are all about shifting load," he says. "It's a matter of shifting peak load demand to off-peak times."

In the case of the thermal storage units, they would consume power during off-peak times and emit heat during peak demand hours, "flattening the load" for local utilities.

In the case of power factor correction, it was simply a matter of applying technology that has been used in an industrial setting to the residential consumer.

The Whitby Hydro study revealed that the average power factor when the units were working was over 99 per cent, compared to the normal 87 per cent when the units were turned off.

"We want to enhance the competitiveness of utilities, and projects like these the potential that is out there," says Mr. Sinclair.

"Utilities have been stretched to the max, struggling just to meet the day-to-day demands of providing a service for customers," he says. "They don't have the resources to do the research.

"With the Fund, we can share the findings of the research with the LDCs; it is to the betterment of everyone."

Although the vast majority of LDCs and other parties haven't taken advantage of the Fund to date, Mr. Sinclair is confident that more LDCs will come on board once they see the benefits to be gained.

"I think it (the Fund) will hit a critical mass, with more and more utilities seeking funding once they get a better understanding of what is available," he says. "And this will spawn additional innovation."

For more information on the LDC Tomorrow Fund, you can contact The MEARIE Group at www.mearie.ca, and click on the Products/Services and the LDC Tomorrow Fund icon.

ET

You said it...

Leslie Field, Senior Product Engineer with General Electric International Relays Corporation in Anasco, Puerto Rico writes:

"I would like more articles on protective relays."

Timothy Maynard, President /CEO /Owner of Powerline Inc./Hyline Inc. in Huntington, West Virginia writes:

"I have heard very good things about this publication. Looking forward to receiving my own issues and any new dealers I am unfamiliar with, (and I am looking forward to) your line of books."

Dean Bacon, District Manager of Maintenance with the Public Service of New Hampshire in Hooksett, New Hampshire writes:

"Best magazine I receive. Some of your issues have more material in them than four years of college. I can hand your magazine to the younger engineers at work and tell them when they understand everything in your magazine, there is nothing else left to do in their careers."

Daniel Ward, Principal Engineer with Dominion Virginia Power in Richmond, Virginia writes:

"Keep up the good work. You have a knack for selecting an interesting array of topics."

Dick Essig, Senior Analyst with Globe Research Associates in Riverside, California writes:

"We enjoy reading the classified advertisers' section."

Lorraine Ilminen, Supervisor of Materials Management with Virginia Public Utilities in Virginia, Minnesota writes:

"I recently received one of your magazines and obtained access to a very competitive vendor for Arc Flash apparel (EGO 1). Thank you."

Thomas Matusiak, an Engineering Specialist with FM Global in Havre de Grace, Maryland writes:

"I find great value in every edition, you are not a magazine, each publication is a technical reference document that I can use to better serve my clients."

Del Paton, Area Manager for Pyramid Electric Corp. in Saskatchewan writes:

"Don, I am emailing you in regards to an article in the Electrical Source Magazine, 'Curing the Cowboy Mentality of Working Live'. We would like to copy this article for use in our monthly Safety Meeting. With permission we would like to photocopy the article and share with other employees in our company."

Roy Smith, an Electrical Engineer with the City of Tulsa Engineering Service in Tulsa, Oklahoma writes:

"Thanks for the super source of information."

EXAMPLES OF PREMATURE STATOR WINDING FAILURE IN RECENTLY MANUFACUTRED MOTORS AND GENERATORS

By G.C. Stone, Iris Power Engineering

Local manufacturers of motors and generators must now compete with other manufacturers from around the world. The result has been pressure on the manufacturers to reduce costs through process.. Improvements, using new materials and/or increasing design stresses.

The stator winding of air-cooled motors and generators has been a particular focus for cost reduction or conversely rated power increases in the same stator frame inevitably, the adoption of these new approaches has resulted in some problems and even failures, sometimes just a few years after the machine is commissioned.

This article provides examples of premature stator winding insulation aging problems, including failures caused by poorly applied PD protection layers, coils installed too close together in the endwinding, coils that abraded due to inadequate bracing in the slot as well as problems associated with the global VPI process. This anecdotal information about the perceived increase in the premature failure rate is validated by a statistical analysis of on-line partial discharge data that shows that some brands have seen a large increase of PD in machines made in the past 10 years. Some suggestions are made that may enable machine owners to reduce the risk of premature winding failure.

INTRODUCTION

As part of the analysis of on-line partial discharge (PD) data performed on thousands of motors and generators, it has been noted that stators made by some manufacturers in the past decade have much higher PD than stators made by the same manufacturer more than 10 years ago [1]. For example, Figure 1 shows the peak PD activity vs. winding manufacturing date for 9 of the world's largest manufacturers of air-cooled motors and generators. This figure shows that for on-line PD readings measured in 2003, four manufacturers are exhibiting much higher PD on recently made stators, than they typically experienced on their machines made before 1995. Since high PD can be often associated with rapid aging of the stator winding insulation system, the high PD in recently manufactured stators is of concern.

Maughan has recently published a catalog of premature winding problems he has seen [2]. This paper presents additional examples of advanced insulation aging that this author has recently seen in air-cooled motor and generator stators. Many of these deterioration processes resulted in premature winding failure. This paper also postulates reasons why some recently made stator winding insulation systems have higher PD activity, and some steps the user may take to reduce the risk of premature stator winding failure.

ELECTRIC STRESS CONTROL COATING PROBLEMS

Most stator windings rated >6 kV employ a carbon-loaded paint or tape on the surface of the coils or bars in the slot [3]. This 'semicon' coating prevents PD between the surface of the coil and the stator core in any small air gap that

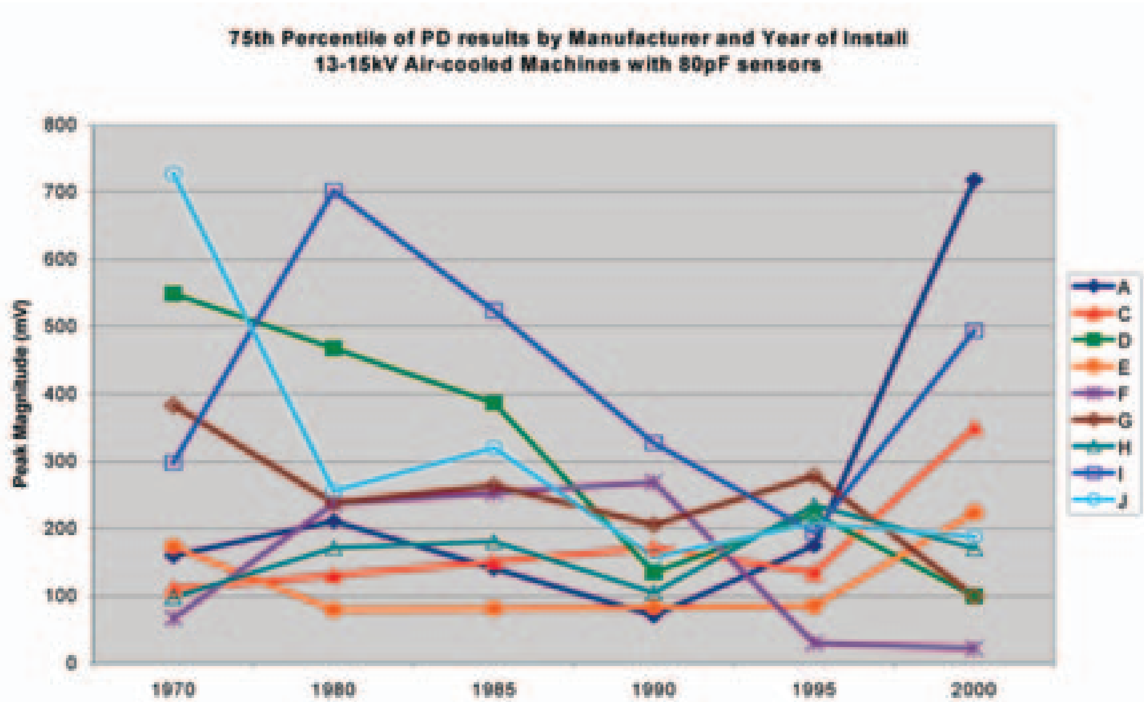

Figure 1: Peak PD activity versus year of manufacture for 9 major manufacturers

inevitably exits at this interface. In addition, most manufacturers use a silicon carbide-loaded paint or tape on the coil for 10 cm or so outside of the slot. This silicon carbide coating overlaps the semicon coating, and reduces the high electric field that would otherwise exist at the end of the semicon coatings.

In the 1970s, there were a number of machines that exhibited very high PD and high ozone concentrations from either or both coatings that were caused by manufacturing problems. The problems seemed to originate from coatings where the carbon and/or silicon carbide was non-uniformly dispersed in the insulation matrix or where the application method resulted in microvoids just under the coating. In both cases the result was PD. This high PD created ozone that chemically attacked the insulation (not to mention heat exchanger metal and rubber components) and properly made areas of the coatings, resulting in the spread of the problem. This problem seems to be worse if the winding insulation operates at higher electric stress and/or higher temperature. Perhaps it is for this reason that there seems to be a recurrence of this problem in the past few years.

Figure 2: Semicon and grading coating overlap deterioration due to poorly applied or inadequate coatings

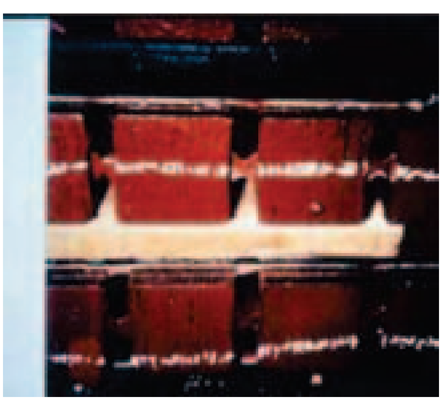

Figure 3: Destruction of the coil semicon coating in the stator slot due to PD and ozone

Figure 2 shows a hydrogenerator stator where a very noticeable white band is visible at the junction of the semicon coating and the silicon carbide coating. Figure 3 shows a winding where the semicon has virtually disappeared in the slot due to poor application of the semicon coating.

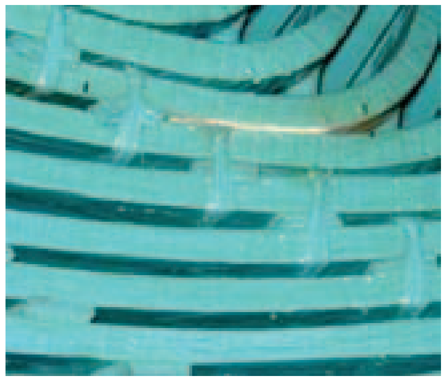

Figure 4: PD occurring between high voltage coils in two different phases, where the spacing is insufficient to prevent the PD. Note that the spacing between adjacent coils is irregular, as a result of poor manufacturing processes.

ENDWINDING PD

Coils operating at high voltage and placed adjacent to other high voltage coils in another phase require a minimum separation to avoid PD in the air space between coils. This PD will gradually erode the groundwall insulation and may lead to phase-to-phase stator failure. The higher the voltage class of the machine and the thinner the groundwall insulation, the greater must be the spacing [3].

Unfortunately, in many motors and generators we have noted inadequate spacing, and consequently high PD (and ozone). Figure 4 shows the white residue caused by ozone resulting from PD between two coils in different phases that were installed too close to one-another.

Figure 5 shows a stator where the close spacing has resulted in highly stressed air adjacent to where two phase end coils (in different phases) make connection to the circuit ring bus. The resulting partial discharge eventually

Continued on Page 26

Stator Winding

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Figure 5: Partial discharges occurring in the inadequate space (here filled with an insulating board) between two phases where the high voltage bars are connected to the circuit ring busses. (Courtesy C. Maughan)

bores a hole through the insulation, triggering a phase-to-phase or a phase-to-ground fault.

LOOSE COILS IN THE SLOT

Coil vibration in the slot has long been a problem in all non-global VPI stators made with thermoset insulation systems such as epoxy mica. The first instances were reported over 50 years ago [3]. The root cause of the problem is that at full load, the twice power frequency magnetic forces will vibrate the coils if the coils are not tightly held in the slot. Consequently, the groundwall insulation rubs against the laminated steel core – a very abrasive surface. First the semiconductive layer of the bar or coil is abraded away, and then the groundwall insulation. The mechanism is sometimes referred to as slot discharge, because once the semiconductive coating is abraded, partial discharges occur between the coil surface and the core, further increasing the rate of deterioration.

Figure 6 shows a coil that was removed from the slot of a hydrogenerator where the semicon and about 30% of the groundwall thickness has been abraded away. The manufacturer had not mechanically secured the coils in the slots by means such as sidepacking, ripple springs, two part wedges, conformable restraint in the slots, etc. Figure 7 shows a bar in the process of being removed from the stator slot that shows significant abrasion of the insulation in the slot, for the same reasons.

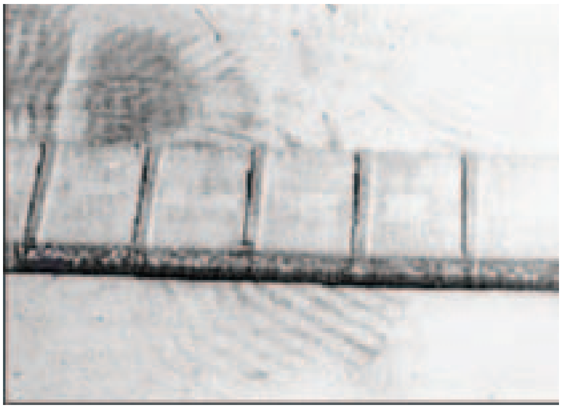

Figure 6: Photo of a coil removed from a hydrogenerator stator that failed due to slot discharge. The vertical stripes are where the insulation is not abraded, since the stator core ventilation ducts are at these locations.

Normally one would not expect loose coils to be a problem in a global VPI stator, since the coils are effectively glued to the stator core. However, if the coils are made too small for the slot, and are subjected to load cycling that creates shear stresses between the coils and the stator core, then loose coils and slot discharge may occur in some designs (Figure 8).

AVOIDING PREMATURE STATOR FAILURE

The premature failures described above were a consequence of the design and/or manufacture of the stator. Specifically:

• The electric stress control problems may be caused by poorly applied coatings. The deterioration process is accelerated in winding designs that cause a class F insulation system to operate above about 120C and/or with an average groundwall electric stress above 3 kV/mm.

• The endwinding PD is probably caused either by: (a) poor dimensional control of the coil and/or inconsistent alignment of adjacent coils in the slots; (b) too short an endwinding which does not allow enough circumference at the coil ends for sufficient air spacing between the connections; and/or (c) inattention to the air space and creepage distances needed when blocking and bracing are installed.

• The loose coil in the slot problems may be due to a slot content design that does not take into account the gradual shrinkage of insulating and wedging materials, or where the need for tight coils has been sacrificed to make the coils easy to install in the slot.

Probably the best way to avoid premature stator winding insulation problems is to have an adequate purchase technical specification. Some suggestions for terms to include in such a purchase specification, in addition to the relevant parts of IEC 60034, are:

• For a 30-year life, require a Class F insulation system to be operated at a Class B temperature rise.

• Require that the groundwall insulation system pass a voltage endurance type test similar to those specified in IEEE Standards 1043 and IEEE 1553 (regrettably there is no IEC equivalent specification that is well defined and has a pass-fail criteria). Requiring a voltage endurance test is probably better than specifying the maximum design electric stress, since this may retard the introduction of new materials and processes. For further assurance, require spare coils from the production batch for a stator to be subjected to a voltage endurance test.

• Require a partial discharge test on the new winding, together with a 'blackout' test to ensure the coils are properly impregnated, and clearances in the endwinding are sufficient [4,5].

• For multi-turn coils, require a voltage surge test both on coils (for non global VPI stators) and complete windings, according to IEEE 522 (IEC 60034 Part 15 is not as effective in detecting weak turn insulation).

• For non-global VPI stators, require the use of a wedging or sidepacking system that contains a follow-up restraint

Figure 7: Bar abrasion due to loose windings in the slot of a turbo generator that did not have sufficient sidepacking or a radial follow-up wedging system.

Figure 8: Example of loose winding failure in a 200 MVA global VPI generator stator.

that ensures tightness as the slot contents shrink. This could include the use of two or three part wedges, ripple springs and/or conformable materials such as silicon rubber. Alternatively consider requiring a clearance between the side of the coil and the core to be no more than 0.1 mm or so.

• Insist on the right to make unannounced factory inspections during manufacture of the stator.

Note that most of the above terms may increase the cost of the stator winding, but will probably result in a longer winding life and less maintenance over the lifetime. The machine owner also has a responsibility to operate the machine within specification, keep the windings clean and tight, and preferably visually inspect the winding before the end of the warranty period. It would also be beneficial if manufacturers could educate users on the trade-offs of cost vs. life they make when designing a new winding.

CONCLUSIONS.

1. Problems such as coil abrasion in the slot, electric stress relief coating deterioration and partial discharges in the endwinding have lead to failures in as short as 5 years of operation. This anecdotal information is supported by the fact that PD for some manufacturers is higher for recently made machines than for similar machines made over 10 years ago.

2. To avoid premature failures, users of modern air-cooled machines should ensure they have a good purchase specification and ensure the manufacturer has an appropriate QA program in place.

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ONTARIO'S ELECTRICITY DISTRIBUTORS NEW LEGISLATION AND THE SMART IMPLEMENTATION OF SMART METERS

By Charlie Macaluso, President and CEO of the Electricity Distributors Association

> Distributors have been clear from the beginning that it is critical that utilities are kept financially whole through this process. Mechanisms will need to be in place to compensate distributors for the premature retirement of existing meters (legacy assets), and the capital costs associated with installing the new meters must be fully recoverable.

The Ontario government's smart meter initiative represents one of the largest smart meter deployments in North America. In fact, implemented successfully, it could very well position Ontario as a leading proponent of smart metering worldwide. There is little doubt that jurisdictions, particularly in the United States, are watching Ontario's progress closely as the province formulates a final implementation plan to facilitate the deployment of this wide-scale venture.

As the industry players responsible for owning, installing, operating and maintaining electricity meters, the province's electricity distributors have assumed a central role in laying the groundwork for smart meter implementation. However, this work is only an initial step in the role distributors will play in the ongoing data management, operations and maintenance of the meters. Distributors will continue on the frontline as the port of call for customers and as the primary billing agents for the electricity system.

On November 3, 2005, Ontario's provincial government tabled Bill 21, the Electricity Conservation Responsibility Act. The bill is being described as 'enabling' legislation as it gives the government the flexibility to determine the best options for the governance, ownership and regulatory structures of Ontario's smart metering initiative in moving forward.

The long-anticipated legislation provides the basic framework to facilitate the government's smart meter initiative, which will see the installation of close to 4.5 million 'smart' meters in every residence and small business in the province by 2010 (the first 800,000 are to be installed by 2007).

The initiative is part of a broader government commitment to create a 'culture of conservation' in Ontario, designed to address peak demand issues and the ongoing strain on electricity supply in the province. With a supporting pricing plan that will come into effect on May 1, 2006, the new time-of-use meters are intended to be the tool that electricity consumers turn to in order to respond to price signals in high and low peak periods.

And while the government has been clear on its ultimate goals for the installation and use of smart meters in Ontario, many of the operational and regulatory details of how smart meters will be installed and managed remain to be formulated. Further clarification will come in the form of new regulation, codes, and Ministry directives, which are expected to flow from the new legislation into early 2006.

CLARIFICATION OF RESPONSIBILITIES IS CRITICAL NEXT STEP

Ontario's electricity distributors believe that the success or failure of smart meter implementation will ultimately depend on a clear and common understanding of the responsibilities to be carried out by each of the players involved, including government and regulators.

Electricity distribution companies have come together and continue to work in industry groupings, tackling key operational and regulatory issues, including the more technical aspects of functionality and meter data standards. This cooperative approach is providing greater efficiencies and is allowing our sector to develop best practices based on a collective approach to testing through smart meter pilots.

Just as importantly, key industry partnerships between distributors and metering companies are bringing together the technological and communications support that will ultimately facilitate full integration of smart metering in the province.

In further formulating the smart meter implementation framework government can leverage these findings and the data collected through smart meter pilot projects. Ontario's distributors are sharing and consulting closely with government decision-makers and regulators in order to further facilitate this important exchange of information.

SMART METER ENTITY – MANAGING METER CONSUMPTION INFORMATION AND DATA

Bill 21 allows for the establishment of a Smart Meter Entity (SME) that will collect, store, manage and transfer meter consumption information and data. The legislation provides government a great deal of latitude on this front and considerable flexibility regarding the ownership and structure of the data entity that will ultimately be established. In fact, the SME could take its form as a 'corporation, a limited partnership, a partnership, or an entity designated by regulation'.

While this process unfolds, electricity distributors are looking to have three key issues addressed and clearly defined:

1. What the basic design of a smart meter system/data pathway will be;
2. What particular communication assets and functions distributors will have the right to own/control; and,
3. What exactly the responsibilities of the SME will be.

With the assistance of an appointed technical advisor, the government is expected to make a final decision on the responsibilities and structure of this important entity in the near future. Ontario's distributors remain engaged with government policy makers to ensure that certain basic parameters identified by our sector are addressed.

LEGACY ASSETS AND CAPITAL COSTS

The scale of the government's plan is monumental. Millions of electricity meters will be disposed of and replaced with close to 4.5 million new time-of-use meters. The Ontario Energy Board has estimated the capital cost of new meters will be approximately $1 billion.

Distributors have been clear from the beginning that it is critical that utilities are kept financially whole through this process. Mechanisms will need to be in place to compensate distributors for the premature retirement of existing meters (legacy assets), and the capital costs associated with installing the new meters must be fully recoverable.

Importantly, Bill 21 allows the Ministry to issue directives to the Ontario Energy Board to allow distributors to recover those costs associated with smart meter deployment through the rate base. It also provides the Minister with the authority to make regulation relating to the establishment of variance accounts and the legislation puts in place a framework for the recovery of costs, including the recovery of stranded meter costs.

Ensuring that the proper cost recovery mechanisms are in place as the smart meter initiative proceeds remains an absolutely critical consideration for Ontario's distributors in moving forward.

NEXT STEPS IN MOVING FORWARD

The proposed legislation will go to the Legislative Committee in early February 2006, before it goes back to the House for third and final reading. Bill 21 will likely be passed into law sometime in the late winter.

There is little doubt that jurisdictions across North America are watching with interest as Ontario works through the final details of implementation.

We are on a cusp as government formulates a definitive framework for the plan. Attention also shifts to the Ontario Energy Board, who will have to put appropriate regulations in place in order to facilitate that plan.

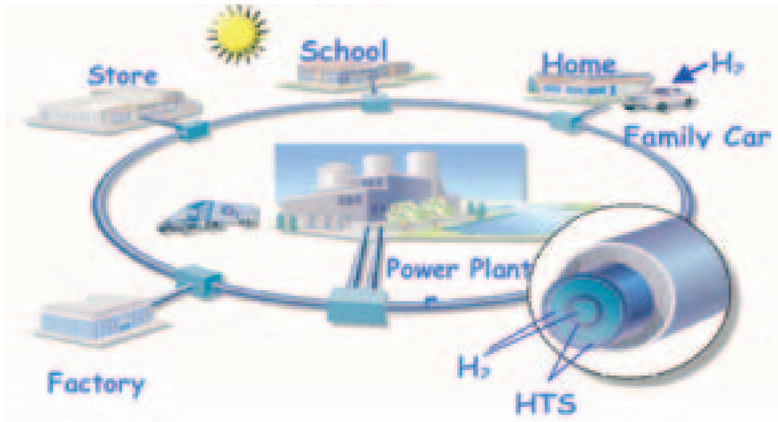
Although we've come a long way, there is a lot of work yet to be done. We can be assured of one thing - key industry players are going to have to work together and with some determination to meet the tight timeline set by government of 2010.

Ontario's electricity distributors are keenly aware of the importance of preparedness in such a large-scale initiative. Through cooperative industry planning distributors have been laying the groundwork, determining which meter technologies address the geographic uniqueness of the province's regions, as well as testing data and communication technologies through ongoing smart meter pilot projects. The expertise and experience that distributors are bringing to the table will go a long way in ensuring a smooth and successful deployment.

The smart meter initiative will require the continuing cooperation and timely action of all key industry players involved – government, regulators and electricity distributors. More than any other factor, this remains the vital component that will realize ultimate success in the smooth implementation of the government's smart meter initiative.

Charlie Macaluso is President and CEO of the Electricity Distributors Association. The EDA is the voice of Ontario's local electricity distributors, the publicly and privately owned companies that safely and reliably deliver electricity to over four million Ontario homes, businesses and public institutions. The EDA provides members with advocacy and representation in the legislative and regulatory environment and the electricity market in Ontario.

THE CASE FOR ADVANCED ELECTRICITY METERING IN TEXAS - PART II



SMART ENERGY POLICY RESEARCH REPORT - EMPOWERING CONSUMERS (THE DEMAND SIDE)

For any market to work properly, demand and supply must both actively seek the price that clears that market. In electricity, Texas has done a far better job of opening its market to new suppliers than it has of empowering customers to express their demand. Customers must be empowered to participate — with timely price information and the tools to control how and when they use energy — if the Texas model will be one in which price is truly set by the competing forces of supply and demand. As the Texas state government transitions from a role of regulating monopoly utilities to that of monitoring a market, demand participation is a crucial counterbalance to the concentration of supply-side market power.

In order to avert crises such as the rolling blackouts and runaway price spikes that crippled California in 2000 and 2001, a framework must be established to enable the market to respond to peak demand challenges. Broad customer participation in the market — supported by effective programs enabling demand elasticity through peak load management, energy efficiency, and behavior modification—is critical to moderating price swings, protecting consumers, and minimizing the negative impact on the environment.

These forces - supply and demand - collide at the electric meter. Large industrial customers in Texas are required to have advanced meters that measure usage in 15-minute intervals, enabling them to leverage excellent rates and even participate directly in the wholesale market. But for 99-plus percent of Texas customers, meters are electromechanical devices that produce only a total of kilowatt-hours, which is then multiplied by an average rate to produce an electric bill.

Traditional meters are thus incapable of providing the true picture. By disconnecting customers from the cycles of the wholesale electricity market — ostensibly to "protect" them from price spikes — they force customers to overpay for most of the power they use, and deprive them of the opportunity to take advantage of lower, off-peak rates. Flat-rate pricing includes expensive "insurance premiums" which are the direct result of a need to invest hundreds of millions of dollars annually for a power-generating infrastructure built to serve peak loads that last only a few dozen hours each year.

Advanced meters, combined with time-sensitive price options from suppliers, can provide the market with the vital characteristic of demand elasticity — in short, the ability of consumers to manage their energy consumption in response to price signals. By reducing consumption during peak periods, the demand elasticity would reduce the amount of generating capacity needed to meet peak demand, and improve the utilization of the grid and generation assets. Research has repeatedly shown that even modest demand reductions by some customers during peak use periods have dramatic positive effects on prices for all users during those periods. The Electric Power Research Institute (EPRI) has found that if only 10 percent of the overall customer load is exposed to real-time pricing, resulting customer demand reductions can reduce price spikes for all customers by 33 to 66 percent.

Eric Hirst, the industry-leading analyst formerly of the Oak Ridge National Laboratory, has studied actual experience in energy markets nationwide to illustrate the potential of customer participation in demand response. His model based on market conditions in

California and the northeast revealed that a 5 percent reduction in peak demand had the result of reducing peak power prices by more than 50 percent.

Hirst has also evaluated the mass-market economic effect of residential time-of-use (TOU) rates as a demand elasticity resource. One such analysis studied prices and market conditions specific to the Pacific Northwest. Assuming an average level of price volatility and 20% participation by residential customers in optional TOU rates, Hirst projected that wholesale electric prices for the year would decrease by $280 million, or 5.5% of a $5.2 billion Oregon/Washington market. Significantly, part of the cost reductions were attributed to the reduced need for new generation plants and transmission lines, meaning that reduced exposure to wholesale peaks lowers costs for transmission and distribution companies and retail providers alike. In a competitive market, this can result in lower prices for all consumers, even those who do not participate in time-based rates.

CHALLENGES IN SYSTEM RELIABILITY

As Californians learned the hard

way, balancing supply and demand for electricity is an increasingly challenging proposition, especially in areas typified by weather extremes, transmission line congestion, and inadequate reserve generation capacity. And while the supply surplus in Texas can be partially attributed to a favorable regulatory climate, there are signs that market forces are already working to erode the comfortable cushion. Twelve of 29 scheduled generation projects were cancelled or shelved in late 2001 and early 2002, the result of market decisions by private companies no longer beholden to state regulators.

One of the state's largest generation companies, American Electric Power, has mothballed eight plants and hopes to mothball eight others, pending approval by the Electric Reliability Council of Texas (ERCOT). Texas Genco, an unbundled affiliate of the former Reliant HL&P vertical utility, announced in October 2002 that it intends to mothball six plants with a total of 3,400 MW of capacity. Nationally, the overall economic viability of independent "merchant" power providers has been called into question as many have found it difficult to compete. Eventually, these capacity reductions and the uncertainty of the merchant power market could have a substantial impact on the Texas reserve margin. Meanwhile, plants that ERCOT requires to remain operable in order to ward off supply emergencies will be supported by costly "Reliability Must Run" contracts, which pay the generating companies to keep the otherwise-uneconomic plants on call.

When the processes of planning, constructing, and retiring power plants are subjected to the cycles of a free market, a soft cycle such as exists today causes excess capacity to decline, as idle assets do not produce profits. As former Texas Public Utility Commissioner Brett Perlman has noted, "No one benefits from having excess capacity. No one wants to pay for it." When the market inevitably emerges from its soft cycle, the reduced capacity places more reliance on peaking plants that were previously fired up only at times of extremely high demand. This strong phase of the market is typified by reliability challenges, and the kind of price spikes that encourage investment in generation facilities. New plants take years to permit and build, however, and when market cycling outpaces construction, the result can be a window of insufficient reserve margin.

A more serious short-term concern is the fact that the state's current generation capacity is not all located conveniently near the load, and the government's ability to control the location of new generation has also been severely curtailed in restructuring. One result has been chronic transmission line congestion, which has cost the market over $300 million annually in "uplifted" charges as dispatchers were required to purchase more expensive power in order to avoid transmission failures on congested lines. The PUCT has launched a massive three-year project to redesign the wholesale market by transitioning to a "Nodal" system of pricing, in which local congestion costs are built into the cost of electricity. Texas

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Nodal is expected to create long-term incentives for relieving the congestion problem through the appropriate location of new generation and transmission resources. The PUCT has also expressed its expectation that Nodal pricing will provide incentives for increased load participation in the market:

The rule is expected to yield important benefits, such as a reduction in local congestion costs; reduced opportunities for gaming and manipulation in the wholesale electricity market; increased price transparency and liquidity in the wholesale electricity day-ahead energy market; increased locational price transparency for resources; more efficient and transparent dispatch of resources in real-time; improved siting of new resources; and a reduction in the amount of new transmission facilities needed to support the reliability of, and competition in, the wholesale electricity market. These benefits will provide participants in the wholesale and retail markets with more accurate wholesale prices, which will facilitate better-informed price responses by customers in those markets. More accurate pricing will lead to more efficient consumption decisions by end-use customers, and the rule may lead to large-scale deployment of advanced demand-response technologies and distributed generation resources, more sophisticated services, and increased efficiency in the consumption of electricity.

For these benefits to be realized, the state must also develop a viable strategy for the deployment of advanced electronic meters.

Transmission line congestion is a particular problem in various parts of the Dallas–Fort Worth Metroplex, where short-term blackouts and brownouts are common. The Dallas-area ERCOT control zone was responsible for roughly half of all uplifted local congestion charges in 2003 — approximately $160 million. The DFW area imports 65 percent of its power, and decreasing that number could exacerbate the region's challenge to reduce nitrous oxide emissions in order to meet its Clean Air Act goals. The locally-generated electricity comes from the state's oldest fleet of generation plants, many of which are logical candidates for retrofit or retirement as a way to curtail emissions. However, ERCOT has concluded that if a significant amount of the local power becomes unavailable, the existing transmission capability into the DFW area will be inadequate to allow imported power to replace it. Even with several new transmission projects underway, "it appears that much more transmission capacity will be needed" to avoid problems of supply inadequacy and voltage instability.

THE ROLE OF DEMAND PARTICIPATION

Demand-side resources are a potentially powerful part of the new market's ability to address these challenges. By promoting a culture of awareness of the varying cost of electricity, demand participation promotes overall energy efficiency, typically resulting in per capita energy use reductions. And because efficient load management and distributed generation are an alternative means to reduce transmission and distribution system congestion, it reduces the need for the construction of new high-voltage power lines in populated areas that are resistant to them. Demand participation contributes to a cleaner environment by reducing the need to bring peaking plants online and delaying the need to build new speculative power plants.

Prior to restructuring, utilities were assigned demand response obligations by the Public Utility Commission of Texas (PUCT), and met them with a system of special tariffs for large industrial customers that were able to interrupt load on short notice. In the restructured environment, market participants are expected to respond to free market forces to fill the void left by this loss of regulatory power. The task of replacing the interruptible rate system with market-based programs for most of Texas has fallen to ERCOT, the independent system operator that oversees more than 85 percent of the statewide grid. The PUCT applied some urgency to the importance of load participation and price responsiveness in the new market, with this part of its June 2001 Final Order approving various ERCOT Protocols:

ERCOT shall develop additional measures and refine existing measures, to enable load resources a greater opportunity to participate in the ERCOT markets. As many of these measures as possible should take effect by January 1, 2002, because existing Commission-approved tariffs addressing load resource participation in the markets will expire this year.

ERCOT's board of directors and committee structure is prominently composed of generation companies and other entities with roots in the regulated utility world, and the development process for its protocols has been dominated by these entities. The result thus far is a wholesale electricity market that is not well suited to demand participation. Low commodity prices and the surplus of available generation have temporarily eroded market incentives for demand response, and the net result has been a decline in demand response capacity in Texas since restructuring.

To meet its obligations under the PUCT mandate, ERCOT has turned to its stakeholder-based Demand-Side Working Group (DSWG). The group has developed protocols for the new load reduction programs, known as Load Acting as a Resource (LaaR) and Balancing Up Load (BUL). Both focus primarily on facilitating payments to large industrial customers who agree to interrupt their service from the grid, sometimes by replacing it with on-site generation

The LaaR program, launched in 2002, allows industrial loads to participate in the ERCOT wholesale capacity markets, and has proven successful. Curtailable load resources may comprise up to 50% of all capacity resources in the Responsive Reserves market, and numerous industrial customers — many of them former interruptible tariff customers who could take advantage of already-installed equipment — are bidding into the market regularly.

Although this provides less capacity today than prior to restructuring, market participants believe the available resources have noticeably suppressed average prices in the Responsive Reserves market.

The BUL program was devised as a way for other loads, primarily industrial but also including aggregated load programs such as Direct Load Control (DLC), to bid into the Balancing Energy market when prices are high due to scarcity of supply. After numerous delays, the BUL program was finally readied by ERCOT in late 2003, but to date has yet to see a customer registered. DSWG members attribute the slow start for BUL to a provision in ERCOT's administration of the program that could penalize customers for another customer's failure to perform.

In theory at least, DLC programs are eligible to be reimbursed by the market for load curtailments irrespective of BUL. ERCOT working groups have written protocols to enable REPs to assign settlement profiles to customers in DLC programs. These may include group residential programs in which controlled load reductions are enabled through smart thermostats or switches on air-conditioners or water heaters. To date, however, no such small customer programs have entered the competitive market. Many REPs have attributed this lack of success to the continuing burdens of executing the new market requirements, and to the overall challenge of building a business case for a mass market program in Texas's competitive choice market. Under the ERCOT market structure, third-party DLC providers cannot participate without the collaboration of a REP. Thus, DLC providers encounter many of the same barriers to entry as advanced metering providers.

Indeed, more than two years after the opening of the market, the role of smaller consumers has yet to be addressed in detail. The ambition behind the following language from the Demand Side Working Group's original recommendations to the PUCT in 2001 remains unfulfilled:

• "Identify other opportunities to enhance the responsiveness of customers to wholesale price changes through better price signals, better metering, behind-the-meter renewable energy projects, distributed generation, consumer education, and other means.

• "Identify impediments to the participation of smaller loads in ERCOT's markets.

This could include a review of ERCOT's load profiling procedures, the communication of market prices to consumers, outreach efforts, and "behind-the-meter" technologies that facilitate consumer response or clip peaks.

• "Coordinate with pending PUCT rulemaking proceedings that are exploring metering and time-of-use rate issues."

THE IMPORTANCE OF PRICE SIGNALS

Improvements in demand elasticity occur only when the market begins to break down the historic disconnect between wholesale and retail prices. This will require a transition from the near-universal dominance of flat-rate pricing of electricity, in which prices are the same regardless of when the power is consumed. REPs realize that DLC, demand response, and energy efficiency are alternatives for electricity supply, and provide demand response service for customers. Smaller customers can increase the market's demand elasticity factor only if their retail rates begin to reflect the cyclical and seasonal fluctuations of the wholesale market. The senior staff of the PUCT's Market Oversight Division (MOD) has focused on this issue, as illustrated by this section of a memorandum to the commissioners:

"If retail customers modify their usage in response to prices in the future, ERCOT will see reduced price volatility, smaller price spikes, and reduced market power by generators. When supplies are tight, small changes in the amount of power demanded can have a dramatic effect on market clearing prices…. "MOD believes that the Commission needs to be the catalyst on this issue. MOD would welcome encouragement from the Commissioners' offices to assign more importance to this issue and spur stakeholders to implement changes that will increase price responsiveness for the demand for electricity…."

Echoing this concern, a consultant's report for MOD, presented to the Commission in October 2002, recommended numerous improvements in the ERCOT markets to encourage demand participation, primarily for improving the performance of the BUL and LaaR programs.

ERCOT's load reduction programs cater to large industrial customers, in part because these customers are large enough to exert influence individually, or sophisticated enough to develop a network to aggregate their loads. A different approach will be required to involve residential and small commercial customers — representing over 99 percent of the customer base, up to two-thirds of the overall load, and a disproportionately higher share of the peak load. Although their vehicles for participating are quite different, residential customers have been shown to have a similar or even proportionately greater capacity for responding to price signals compared to large industrials. Even if system limitations preclude

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them from participating directly in the wholesale markets, they can exert more control over their own energy costs — and thus increase demand elasticity —through programs involving time-sensitive electricity rates.

ADVANCED METERS: THE ENABLING TECHNOLOGY

For 99-plus percent of Texas customers, electricity consumption is measured through a single monthly reading of kilowatt-hours (peak demand is also recorded for commercial customers with over 10kW of demand). The meters measure gross consumption without regard to when the energy was consumed.

In recent years, the meter industry, mirroring the broader technology explosion, has produced increasingly powerful and affordable new products. Already in use by many large commercial and industrial customers in Texas, and by smaller customers in other markets, advanced meters offer a critical upgrade from traditional meters: they produce more detailed usage data by measuring energy consumption in intervals or time blocks. This feature enables customers to view and manage their usage during critical peak periods, and is necessary for electricity providers to offer time-sensitive pricing options. (Depending on the customer and the meter functionality, pricing plans may include sophisticated real-time pricing (RTP) in which (typically larger) customers pay rates that track wholesale market prices, or more simple time-of-use (TOU) rate plans that enable customers to save money by shifting some consumption to lower-priced periods of the day that are established in advance. Other rate plans include "critical peak" or "call option" packages that reward commercial customers or aggregations of smaller users for curtailing loads, typically on 24 hours notice, during a few super-peak events per year. Other plans combine TOU and critical peak by offering predictable but variable rates for the vast majority of days, with the provider retaining the ability to raise rates to critical peak levels for a certain number of hours per year.)

Another feature of the advanced meters available today is the communications capacity.

Advanced meters almost always deliver the customer's consumption data to the meter-reading entity automatically and remotely through a secure communications network.

Automatic Meter Reading (AMR) — either fixed network or "drive by" — has significantly reduced costs for many utility companies, and networked metering communications services can greatly enhance the value of demand participation by making the data available to providers and customers on a timely basis.

Certain types of AMR technology simply replace traditional monthly walk-up meter reads with monthly automatic meter reads, and many utilities have added AMR communications to their meters without including a demand participation component. Meters with an AMR component represent at least 16.9% percent of U.S. electricity meters, with 32 percent of all U.S. utilities reporting at least some meters read through AMR. However, only 13% of utilities with AMR report using it for time-of-use pricing. This suggests that for the mass market, many utilities have made successful business cases for AMR primarily to reduce costs for their monthly kWh reads. It should also be noted that a demand participation component is not dependent on AMR systems, as some TOU meters may be read by walk-up meter readers using hand-held electronic devices.

Most advanced meters today are modular, providing scalability and versatility for customers, electricity providers, and meter reading entities.

Most advanced meters today are modular, providing scalability and versatility for customers, electricity providers, and meter reading entities. Depending on the service area (terrain, customer density, building type, etc.) and the number of features required, the product price of advanced meters, especially those suited for smaller-demand customers, has dropped in recent years to less than $100 for new meters, and even less to retrofit electromechanical meters.

The value of a kilowatt-hour is greater at peak than off-peak. Thus, the difference between demand participation and traditional energy conservation or energy efficiency is that the energy use reductions are targeted to specific periods of time. California's problems occurred in spite of the nation's lowest residential per capita use of electricity, according to the Congressional Budget Office (CBO), which found that the state failed to address demand response among smaller customers because they lacked the enabling technology, beginning with

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SECURITY IN AUTOMATED T&D SYSTEMS, AUTHORIZATION, AUTHENTICATION, INTEGRITY AND CONFIDENTIALITY

By Juan C. Asenjo, CISSP

The security of automated electric transmission and distribution (T&D) systems delivering power to industrial, commercial, and residential users is critically important to ensure continued and uninterrupted service of this vital resource. Electric utility T&D systems link generating facilities with end users customers through a complex network of high voltage power lines and primary and secondary distribution substations.

Because of ever-increasing demand and limited generating capacities, efficient T&D of electricity is vitally important to adequately fulfill user needs and fuel the economic engines of countries around the globe. Because T&D systems are monitored and controlled through mostly electronic means from remote locations, protecting these assets against potential cyber attacks is critically important to ensure their continued availability in today's heightened security climate.

This article examines specific aspects of existing T&D systems that are vulnerable to cyber attack and addresses how these can be effectively protected to improve their security and mitigate risks.

T&D systems dispense electric power from their generating sources to the end users by distributing and converting electricity from high-voltage levels used to convey power over large distances to voltages that can be safely used by end customers. In doing so, the systems employ Supervisory Control and Data Acquisition (SCADA) mechanisms to monitor and control the supply of electricity to meet the specific customer demands.

SCADA mechanisms connect operators at centralized monitoring and control centers with substations where distribution grids are activated and where transformers are brought on line to step down high voltage feeds for subsequent localized distribution and consumption. SCADA systems reduce labour costs and allow system-wide monitoring and remote control of field sites and devices using specific communications protocols.

To enable this functionality, centralized control centers connect directly with Remote Terminal Units (RTUs) and Intelligent Electronic Devices (IEDs) which are directly linked by local wiring to the transformers and switches that distribute power according to demand fluctuations. Communications between SCADA master control centers and associated RTU/IEDs are vulnerable to interception and alteration. In addition, remote access and maintenance of RTU/IEDs by field technicians is also a critical security aspect.

A schematic representation of the interaction between centralized control centers, remote maintenance access, and substations equipment is shown in the figure shown above:

Because alteration of the data these mechanisms report and the control signals these are given by operators can lead to severe operational disruptions, these systems must be protected against unauthorized access, and the information traversing these secured to ensure its integrity and confidentiality.

SCADA systems have been in place for over 40 years and were originally designed and installed at a time when there was little concern for communication security. The systems have a typical operational life cycle in the order of 15 to 30 years, and with the recent focus on security, will take significant time to fully transition to a completely secure system.

Improving the security of legacy SCADA systems against cyber attack requires flexible security solutions that are easy to install and do not impact system performance and operations.

To address the security needs of the electric industry, the North American Electric Reliability Council (NERC) is developing a Critical Infrastructure Protection (CIP) standard to provide guidelines on the establishment of security policies and procedures, including cyber

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security. The deployment of retrofit security solutions can provide significant advantage when looking to overhaul the security posture of T&D systems in place today and enable fielded systems to be brought into compliance while embedded security features are designed and made available to the market as part of future more robust SCADA systems.

The specific security requirements of electric T&D systems and their respective SCADA mechanisms include protection for authentication to ensure that correct users and devices are connected, integrity to ensure correct feedback and commands are received and issued, and confidentiality to prevent interception and play back. Remote access maintenance is also a vulnerable aspect of SCADA mechanisms. As these permit entry into field substation devices by maintenance technicians through dial-up connections with little or no authentication, role based access control is critically important.

In the following paragraphs, each of these aspects, including SCADA circuit protection, modes of operation and remote access security are examined in further detail.

SCADA circuit protection typically refers to point-to-point applications connecting SCADA master control centers to remote RTUs and IEDs in the field. SCADA communications typically operate at low speeds in the order of 300bps to 9,600bps. Communication links normally used for these applications include; dial-up phone, leased line, spread spectrum radio over asynchronous connections, or routed networks.

When these circuits are deployed in point-to-point scenarios, the connection between the SCADA master and remote RTUs require only a discrete one-to-one security scheme allowing the use of a simple link encryption device. Multi-drop scenarios where the SCADA master control is connected to multiple RTUs in the field are more complex and require a point-to-multi-point encryption scheme that, using the communications protocol employed such as MODBUS or DNP, can create specific protected tunnels between the various fielded devices and the control center.

An additional configuration commonly found in many network infrastructures is the mixed-mode scenario where not all connections to remote RTUs and IEDs need to be secured. In these configurations, two or more RTUs downstream in the network may be configured with multiple addresses for encryption or clear operation. Mixed-mode environment will be commonly found in SCADA networks that are in the process of being transitioned to secured operation, and support for this application will provides tremendous flexibility as encryption solutions can be added as required and in accordance with established security policies and priorities.

As government pressure continues to build to secure critical infrastructure assets against cyber attack, and as industry organizations such as NERC finalize specific standards and recommendations dictating how to secure deployed SCADA systems, retrofit commercial solutions with the characteristics outlined in this article will begin to enter this niche market.

One such product, the Datacryptor SA, offers National Instituted of Standards and Technology (NIST)-approved cryptography for authentication and encryption of SCADA connections and maintenance port access, and offers protection of SCADA networks and remote access to field devices (RTUs and IEDs). The solution supports serial asynchronous communications from 300bps to 115.2Kbps and is designed to meet emerging industry regulations and standards such as those being developed by NERC. The retrofit security solution uses the Advanced Encryption Standard (AES) to protect the integrity and confidentiality of data as well as to secure user-access control.

Unprotected SCADA mechanisms are vulnerable to cyber attack. Interception, alteration, and replay of data exchanged by these can allow an intruder to effectively seize control of a utility's T&D system. Improving the security of these systems requires flexible solutions that are easy to installation, simple and transparent to operate, and have no impact on operational performance.

Because SCADA mechanisms have typical useful lives of over 15 years, retrofit solutions address immediate security concerns. Authentication and encryption of communications links between master control centers and fielded RTUs and IEDs and secure remote access to maintenance ports are key elements of a comprehensive strategy to enhance cyber security of T&D systems.

Mr. Asenjo has over 20 years experience in the information security field, formerly with the National Security Agency, and most recently with Thales' product development and marketing departments. He has degrees in Engineering, Business, and is a Certified Information System Security Professional.


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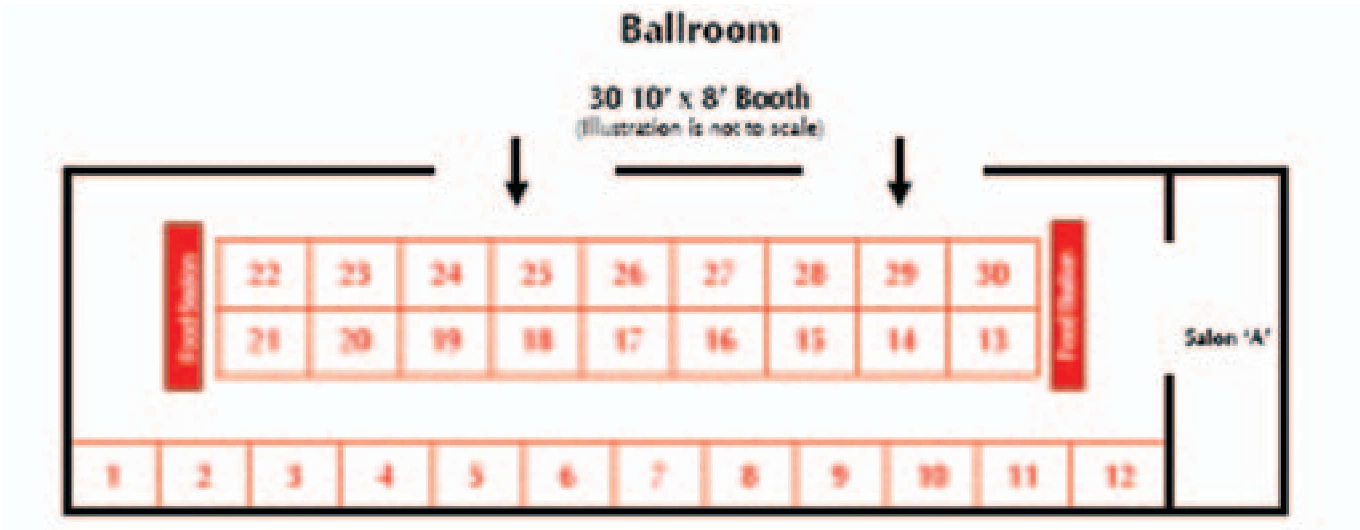

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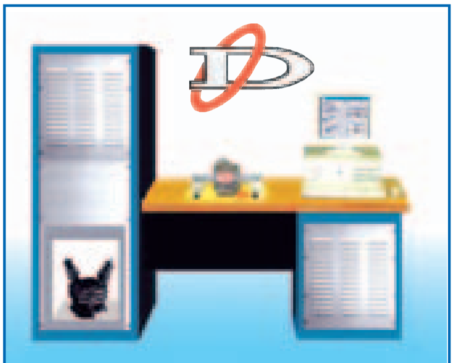

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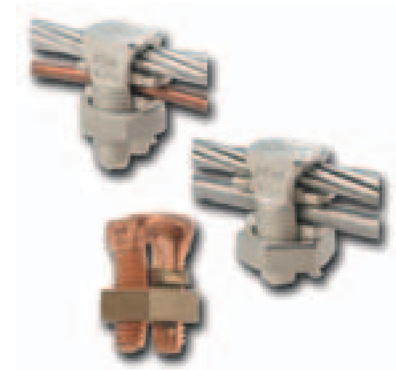

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advanced meters. "(These customers) have acquired few devices that would let them reduce electricity use on short notice, such as real-time meters (which would tell them when prices were changing)," according to the CBO. "Successful restructuring may necessitate that residential and commercial customers acquire many of the same demand-management capabilities that industrial consumers have."

NEW PRODUCTS, SERVICES & TECHNOLOGIES: THE PROMISE OF DEREGULATION

Given adequate incentives, small customers can save money and increase demand elasticity by rescheduling the non-essential functions of energy-intensive appliances such as clothes washers and dryers, water heaters, dishwashers, and pool pumps. Further, price signals alter the economics for acquiring many other innovative products and services for focused energy efficiency, including:

- Software applications that allow customers to retrieve energy use data via Internet or closed network. One poll discovered that 62 percent of residential customers said they were interested in viewing their energy usage on the Internet;
- Energy-saving technologies such as programmable "smart" thermostats, timers, remote-controlled switches, and devices that cycle or curtail high-consumption appliances during peak use periods - either automatically or as the result of signals delivered by the utility or the consumer; and
- The burgeoning technologies of "smart home" gateway management systems that feature robust energy-saving tools as a major component of home and business management platforms.
- Energy storage technologies such as thermal storage, battery storage, photo-voltaics, fuel cells, etc.

Especially if combined with these and other types of automation technologies, load shifts that result in meaningful demand elasticity require only modest changes in behavior and little or no sacrifice of convenience.

Most advanced meters may be readily configured for bi-directional net metering; the function that permits customers to sell qualifying self-generated power back to their provider. In Texas, net metering rules were passed in 1986 in an effort to encourage smaller customers (under 50kW in demand) to install renewable resources such as rooftop solar panels. The rules will require clarification in the new market, where competitive REPs have replaced the vertical utilities as the electricity providers. Combining net metering with time-sensitive pricing could further enhance the value and return on investment of small-scale clean energy sources by providing stronger incentives to consumers to offset the costs of peak power.

Advanced meters can thus enhance demand participation capabilities through peak load management, energy efficiency, and distributed generation. They offer the prospect of faster return on investments and the opening of new markets for promising energy management products and services. Former PUCT Commissioner Perlman suggested that pursuing more advanced metering capabilities will help Texas to become a "center of innovation in energy technologies". Viewed this way, advanced meters can be seen as a driver of economic development and the catalyst for a transformation of retail electric competition.

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