UTILIMETRICS
Alliance for Advanced Metering & Data Management Solutions

Autovation 2008
The Utilimetrics International Symposium
September 7-10, 2008
Georgia World Congress Center/Omni Atlanta
Atlanta, GA

North American Policies and Technologies

Electricity Today

Transmission & Distribution

THE ELECTRICITY FORUM

September 2008
Volume 20, No. 7

Getting bigger and better

Coldshrink turns 40

Cover photo shows Manitoba Hydro employees utilizing 3M Coldshrink Technology - page 26

PUBLICATION MAIL AGREEMENT # 40051146

ELECTRICITY TODAY

Publisher/Executive Editor
Randolph W. Hurst
randy@electricityforum.com

Associate Publisher/Advertising Sales
Carol Gardner
carol@electricityforum.com

Editor
Don Horne
don@electricityforum.com

Web Site Advertising Sales
Barbara John
forum@capital.net

Circulation Manager
Colleen Flaherty
colleen@electricityforum.com

Production Manager
Alla Krutous
alla@electricityforum.com

Layout
Cara Perrier
mac@electricityforum.com

Visit our Web Site:
www.electricityforum.com
E-mail: hq@electricityforum.com

Subscribe on-line:
www.electricityforum.com/et/subscribe.htm

Phone:
905 686 1040

Electricity Today *Magazine* is published 9 times per year by The Electricity Forum [a division of The Hurst Communications Group Inc.], the conference management and publishing company for North America's electric power and engineering industry.
Distribution: free of charge to North American electrical industry personnel who fall within our BPA request circulation parameters. Paid subscriptions are available to all others.
Subscription Enquiries: all requests for subscriptions or changes to free subscriptions (i.e. address changes) must be made in writing to:
Subscription Manager, Electricity Today
215-1885 Clements Road,
Pickering, Ontario, L1W 3V4
or on-line at www.electricityforum.com.

Canada Post - Canadian Publications Mail Product Sales Agreement 40051146
ISSN 0843-7343
Printed in Canada.

Member of:
CCAB BPA WORLDWIDE BUSINESS

Volume 20, No. 7 September 2008

in this issue

editorial board

ELECTRICITY TODAY


BRUCE CAMPBELL


CHARLIE MACALUSO


DAVID O'BRIEN


SCOTT ROUSE


DAVID W. MONCUR

BRUCE CAMPBELL, LL.B., Independent Electricity System Operator (IESO)

Mr. Campbell holds the position of Vice-President, Corporate Relations & Market Development. In that capacity he is responsible for the evolution of the IESO-administered markets; regulatory affairs; external relations and communications; and stakeholder engagement. He has extensive background within the electricity industry, having acted as legal counsel in planning, facility approval and rate proceedings throughout his 26-year career in private practice. He joined the IESO in June 2000 and is a member of the Executive Committee of the Northeast Power Coordinating Council. He has contributed as a member of several Boards, and was Vice-Chair of the Interim Waste Authority Ltd. He is a graduate of the University of Waterloo and Osgoode Hall Law School.

DAVID O'BRIEN, President and Chief Executive Officer, Toronto Hydro

David O'Brien is the President and Chief Executive Officer of Toronto Hydro Corporation. In 2005, Mr. O'Brien was the recipient of the Ontario Energy Association (OEA) Leader of the Year Award, establishing him as one of the most influential leaders in the Ontario electricity industry. Mr. O'Brien is the Chair of the OEA, a Board Member of the EDA and a Board Member of OMERS.

CHARLIE MACALUSO, Electricity Distributor's Association

Mr. Macaluso has more than 20 years experience in the electricity industry. As the CEO of the EDA, Mr. Macaluso spearheaded the reform of the EDA to meet the emerging competitive electricity marketplace, and positioned the EDA as 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.

SCOTT ROUSE, Managing Partner, Energy @ Work

Scott Rouse is a strong advocate for proactive energy solutions. He has achieved North American recognition for developing an energy efficiency program that won Canadian and US EPA Climate Protection Awards through practical and proven solutions. As a published author, Scott has been called to be a keynote speaker across the continent for numerous organizations including the ACEEE, IEEE, EPRI, and Combustion Canada. Scott is a founding chair of Canada's Energy Manager network and is a professional engineer, holds an M.B.A. and is also a Certified Energy Manager.

DAVID W. MONCUR, P.ENG., David Moncur Engineering

David W. Moncur has 29 years of electrical maintenance experience ranging from high voltage installations to CNC computer applications, and has conducted an analysis of more than 60,000 various electrical failures involving all types and manner of equipment. Mr. Moncur has chaired a Canadian Standards Association committee and the EASA Ontario Chapter CSA Liaison Committee, and is a Past President of the Windsor Construction Association.

- ☑ Smart RTU
- ☑ Relay Communications Processor
- ☑ Distribution Automation Controller
- ☑ Sequence of Events Recorder
- ☑ Alarm Annunciator
- ☑ HMI Server
- ☑ Secure Substation Gateway

OrionLX 19-Inch Rack Mount

The NEW Orion Automation Platform.
Check it out.


Orion5 Transducer Mount and Orion5r 19-Inch Rack Mount

from NovaTech®
www.novatechweb.com

Visit www.novatechweb.com/orion.cfm or call 913.451.1880 for product information and the following application documents:

- Smart RTU
- Protective Relay Integration
- Distribution Automation
- Sequence of Events Recording
- Alarm Annunciation
- WEBserver™ HMI

Orion Automation Platform

Yeah. It'll do that.

A VALUABLE LESSON LEARNED BEFORE THE OLYMPIC TORCH ARRIVES

By Don Horne

The July downtown blackout that hit Vancouver was the best thing that could have happened to that city, and to Canada's image.

Fast forward to 2010 and move that power outage to the height of the Olympic Winter Games. We would have the world sitting in darkness at the Vancouver Exhibition & Convention Centre, as that is where the international broadcast and main press centres will be located.

For two days

The Olympic organizing committee says that such a situation would probably have been avoided during the Games, as BC Hydro will have a secondary supply of power coming from a different substation. As well, emergency diesel generators will be on hand in case that second substation fails.

As an official supporter of the 2010 Games, BC Hydro has promised no power failures during the Olympics, providing primary and secondary sources of power to most of the venues.

And before the failure of the cable and eventual fire that incinerated 14 circuits on that Monday morning, it looked like a promise that could be counted on without question.

BC Hydro has one of the most reliable electricity supplies in the countryin the downtown Vancouver area, with an impressive record of supplying steady power 99.9886 per cent of the time – a better record than Toronto, Edmonton or the nation's capital.

As BC Hydro president Bob Elton said, there were people who had worked for the utility for more than 30 years who had never seen anything like it before.

All involved are saying that a catastrophic failure of this kind will only make them stronger – a learning opportunity to ensure that a blackout of this kind doesn't occur two years from now.

Very true.

The idea behind having BC Hydro come on board as an official sponsor was to save the organizing committee roughly $20 million in diesel backup generators. Notwithstanding, there will still be about 100 diesel generators purchased for the International Broadcast Centre and for remote areas.

This same hard lesson technique is being used in a variety of ways, from utilities clear-cutting trees to maintain transmission and distribution integrity to the federally mandated power corridors that can be created without local or state consent.

It's all for the greater good, and any complaints can be directed to the blackout of 2003 to show how allowing local indecision or lax maintenance can lead to widespread problems.

Although British Columbians pride themselves on their high degree of renewable hydroelectric generation, it won't account for much if the infrastructure cannot transmit that green and clean power to the Olympic venues.

One of the great benefits of any Olympic Games is the rejuvenation of a city's infrastructure. Improved public transit, recreational facilities and housing go hand in hand with the preparations for an Olympics, and once the dust has settled and the athletes return home to their respective countries, the local citizenry begin to enjoy what was created.

Certainly BC Hydro is beefing up their service for the Games (it should be said that BC Hydro already has some of the best redundancy infrastructures of any like-sized utility), but no doubt much more of the network could be either updated or expanded while the Olympic fever (and dollars) is still flowing freely in the city and province.

It should also be said that BC Hydro has asked for permission to pay industrial customers to shut down operations on peak winter days when the system gets close to capacity.

Recent filings with B.C. Utilities Commission state that the grid is "significantly exposed" to the risk that BC Hydro won't have enough power in the system when four million residents flick on lights, furnaces and other appliances during the dead of winter.

When the 2010 Vancouver Winter Olympics will be in full swing.

And that is the reality of today's grid – even the most prepared utility with the best backup systems around are still struggling to meet peak demand.

A consultant with Hydro One who has worked in the industry for 30 years says that of Ontario's 1.2 million distribution poles, an average of 50,000 poles turn 50 years old every year. Unfortunately, the utility can only test a maximum of 10,000 annually.

And in the case of Toronto Hydro, they had their hands full with two electrical underground vaults in apartment buildings exploding and catching fire in the space of a few days. Although not affecting anything beyond the buildings, they do point to an aging infrastructure nationwide.

Underground transmission and distribution cables, electrical vaults and substations aren't as sexy as a new sports arena, but they are very necessary for a city to survive and thrive.

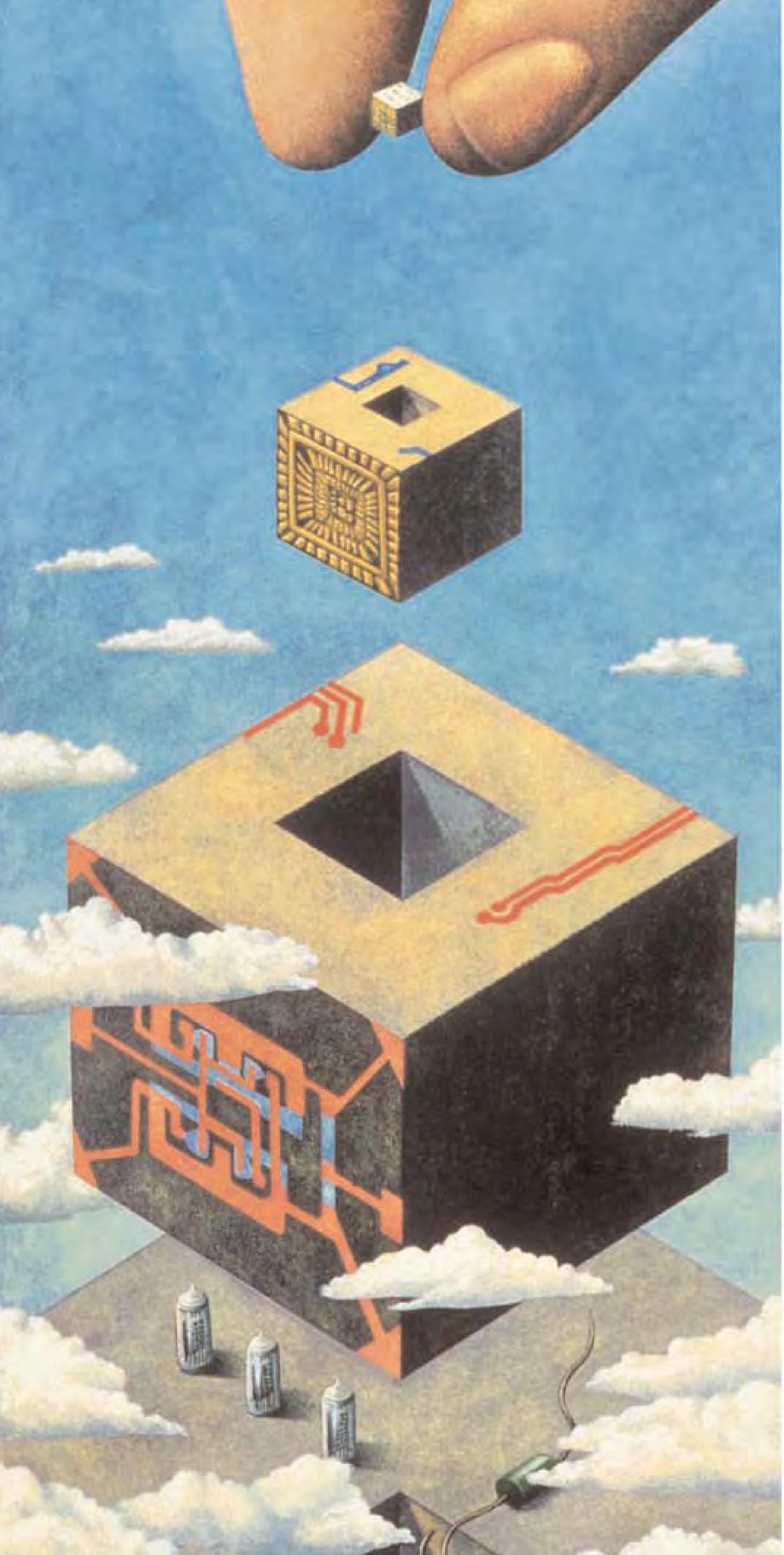
Actually, these incidents would be an excellent example for utilities everywhere to point out the potential problems of aging infrastructure and/or a lack of redundancy systems. Municipal budgets are tight, but the need to keep the wheels of commerce turning are crucial to keeping a good corporate image for any city – and no one wants to move their headquarters to a downtown plagued by frequent power outages or brownouts.

During the Vancouver blackout, the cost to small business is estimated to have cost $36 million.

As for Vancouver, it would appear that the fire and blackout was a Perfect Storm of unfortunate events. Fingers crossed, BC Hydro should count its blessings that bad luck happened now, and not when the world spotlight was shining on the city.

But for a utility and province that prides itself on being eco-friendly, it would be ironic indeed if another unforeseen massive power outage occurred, forcing organizers to flip the switch on the diesel generators and have the Winter Games run on Alberta crude.

don@electricityforum.com



PLANNING IMPROVEMENTS AT PACIFICORP

By Randy Rhodes, Manager, Planning Technologies, PacifiCorp

ABSTRACT

PacifiCorp has improved T&D planning by implementing new analysis techniques and new software applications in recent years. Planning engineers guided these changes, which included improved load data management, spatial load forecasts, and better management of planning models. The presentation includes a simulated video fly-over of a 3-dimensional model of future load growth in the Salt Lake City, Utah area.

CORPORATE BACKGROUND

PacifiCorp is one of the lowest-cost electricity producers in the United States, serving more than 1.6 million customers. PacifiCorp has more than 10,400 megawatts of generation capacity from coal, hydro, renewable wind power, gas-fired combustion turbines, solar and geothermal.

PacifiCorp operates as Pacific Power in Oregon, Washington and California; and as Rocky Mountain Power in Utah, Wyoming and Idaho. The company was acquired by MidAmerican Energy Holdings Company in 2006.

PacifiCorp has more than 73,000 miles of transmission and distribution lines and 136,000 square miles of service territory.

The transmission system is interconnected with more than 80 generating plants and 15 adjacent control areas at 124 interconnection points. In May 2007, PacifiCorp announced plans to invest more than $4 billion to improve and expand the transmission system. When the transmission expansion projects are complete, PacifiCorp will have more than 17,500 transmission line miles — more than any other utility in the region, including the Bonneville Power Administration.

PACIFICORP NETWORK DIVERSITY

PacifiCorp's six-state service territory includes diverse characteristics compared with other utilities. This is due in large part to its history. Pacific Power & Light was founded in 1910, in Astoria, Oregon, along the Pacific coast. Once established, PP&L acquired other companies, properties and service areas and began building transmission systems and extensions to serve rural customers in Oregon and Washington, and later, Wyoming and Montana. PacifiCorp itself was formed in 1984 and Utah Power & Light (UP&L) was acquired in 1989.

PacifiCorp Transmission Expansion Plan

Characteristics of the company's history and service area create many system planning challenges.

• Diversity in geography. The system includes both winter-peaking and summer-peaking areas, and many formerly winter-peaking areas are becoming summer peaking. Some facilities in Wyoming can only be reached by snow track vehicles during 5 months of the year. Other facilities in southern Utah are subject to desert heat conditions.

• Diversity in customer base. PacifiCorp serves customers in remote recreational areas in mountainous Oregon; farmers in southern Idaho; large mining and gas companies with facilities in Wyoming, and high-tech business and research facilities in Salt Lake City.

• Diversity in system design. The subtransmission and distribution network encompasses 19 line-to-line voltage levels, with a variety of wye and delta distribution voltage combinations. Long (even 50-mile) radial feeders are common in extreme rural and mountainous areas, compared with redundant networks in place in urban Portland and Salt Lake City.

• Diversity in past planning and investment practices. Because of a long history of acquisitions and mergers, system reinforcement practices have been affected by prevailing corporate business situations. Some areas of the system have been affected by low capital investment policies, while others demonstrate high compliance to engineering standards.

These characteristics present PacifiCorp asset management and system planning engineers with unique challenges.

GROWTH AREAS

Across the six states served by PacifiCorp, the largest growth area from a demand viewpoint is the Salt Lake City, Utah metropolitan area. This area represents over 90 percent of the customers in the state of Utah and over 4,300 megawatts of summer peak load. Since this area lies along a mountain range, it is known as the Wasatch Front and is approximately 90 miles long by 20 miles wide.

This area also exhibits some unique characteristics from a system-planning viewpoint, including geographical diversity. Suburban growth patterns, weather "microclimates," and air conditioning usage are all affected by having the Great Salt Lake on one side and the Wasatch Mountains on the other. The area also has the highest birth rate in the nation and a diverse local economy.

Continued on Page 10

FLUKE®

These NEW Fluke Thermal imagers help you locate and solve problems faster and are so affordable, you won't have to share!

The Fluke Ti25 and Ti10 Thermal Imagers detect problems in:

- Electrical installations
- Electro-mechanical equipment
- Process equipment
- And other industrial applications

Fluke patent-pending IR-Fusion Technology provides a full thermal image, or one combined with a visual image that identifies exactly what you're looking at.

- Small temperature differences and fine details are revealed on the large display
- Voice recorder notes for images
- Store more than 3,000 basic thermal images
- Withstands a 2 meter drop
- Measure up to 350 °C (662 °F) with the Ti25

The Ti10 and Ti25 thermal imagers, the ultimate tools for troubleshooting and maintenance for almost any application and budget!

Fluke. *Keeping your world up and running.®*

IR-Fusion®
puts problems clearly in the picture

Request a demo and find out how thermal imaging can help you see problems faster.
Go to www.flukecanada.ca

PacifiCorp Improvements

Continued from Page 8

Together, these factors contribute to a sustained year-over-year demand growth well above the rest of PacifiCorp service territory.

Other areas within the PacifiCorp service territory exhibit high growth rates, although on a smaller scale. Socioeconomic factors such as the expansion of baby-boomer retirement and certain types of industry are driving pockets of growth. Examples are Bend and Medford (Oregon); the St. George/Cedar City area (southwest Utah); and Park City (near Salt Lake City, sometimes referred to as the "Wasatch Back").

PLANNING IMPROVEMENTS

Since 2001, PacifiCorp has implemented a variety of new system planning approaches.

Examples discussed here include:

- Load Data Management
- Spatial Load Forecasting
- Planning Model Management

LOAD DATA MANAGEMENT

Substation and circuit load data is critical to the operation and planning of all aspects of the PacifiCorp transmission and distribution system. This data is critical to capital expenditure recommendations, which can reach hundreds of millions of dollars each year. PacifiCorp initiated a project over five years ago to improve the management of this data. Because of the high percentage of rural substations, around one half of substations are not equipped with SCADA or other automated methods for capturing load and asset data. This required load data to be collected during monthly asset inspection cycles. Some substation load data was collected via meters, with data stored in a meter data management system. Therefore, area planners and distribution engineers had to access data residing within numerous systems in order to assemble a picture of actual loading conditions in the field. This was an arduous process with many manual steps.

PacifiCorp implemented a new system to replace and consolidate the multiple repositories for substation and circuit load data. The new system incorporated load data from four sources into one for use across PacifiCorp. This system was dubbed SCHOOL, for Substation/Circuit History of Operational Loading.

The SCHOOL system has become an important tool set for planning engineers. PacifiCorp has developed a number of planning tools that are entirely engineer-designed. The IT department role is clearly defined – server support, infrastructure and software upgrades, desktop client support, etc. Engineers enjoy the ability to customize their own tools, building in the features that make the system truly useful. Some of the tools include:

• An Excel report that connects to the PI server to create a load duration curve for a single tag or a mathematical combination of tags and values. Tags, time range and interval are all user specified.

This is used to find coincident load sums of multiple assets (transmission lines, transformers, feeders); coincident MVA of asset's MW and MVAR loads; hours of overload; days of overload; and contingency exposure for N-1 conditions. Planners can quickly and objectively prioritize infrastructure reinforcement options according to greatest overload risk and duration.

• An Excel tool that calculates peaks for a SCADA tag and finds the coincident peaks for other tags. Summations are also supported. Area Planners use this to find peak load values from a tag's data stream (or multiple tags, on a coincident basis). Planners can find hourly, daily, weekly, monthly or annual peaks averaged over minutes, hours, etc., eliminating the need to create and analyze trend displays.

• A customized trending tool that allows a SCHOOL user to select and view load data using a hierarchical tree structure for quick navigation. Engineers can quickly display a trend of up to 10 tags on the same graph and establish correlations, growth trends, anomalies, maximums, minimums, etc. Time is saved since the drill-down hierarchy allows quick access to desired tags.

A post-investment appraisal showed system payback in less than two years due to planning and operational efficiencies. And, since the SCHOOL system is based on commercial software (OSIsoft PI) and the underlying infrastructure complies with IEC CIM standards, the system is also a very capable integration platform.

Following are SCHOOL system-related improvements that have provided value to the system planning processes at PacifiCorp.

• A new ABB Network Manager Energy Management System was put into production in 2006. This system also used OSIsoft PI software as its data historian. A PI-to-PI project developed a CIM-based repository for managing tag metadata for the interface between these two systems. This has become a popular central reference point for engineers and will be expanded with additional equipment data in the future.

• The interface for transferring data from the control center into SCHOOL (on the corporate WAN) was designed using CIM/XML messaging on the existing TIBCO information bus architecture. The loosely coupled integration design, using adapters for each application, made the migration from the old EMS environment to the new a relatively simple matter.

• The initial rollout of the SCHOOL (PI) system did not include performance testing, and performance of some functions proved unacceptable at outlying offices. A SCHOOL Infrastructure Upgrade project implemented a Citrix-based architecture for remote users.

This dramatically improved application performance across the wide area network.

SPATIAL LOAD FORECASTING

PacifiCorp first introduced spatial load forecasting methods into the company in late 2001 due to the growth in the Wasatch Front region. Spatial load forecasting uses GIS to merge distribution system data with land use and development data. The model uses data such as current land use, transportation infrastructure, mountain slopes, and urban centers to forecast the extent, location, and the timeline of community development. Every land use is related to a predefined profile of load on the distribution system. The model then translates the land use into a system load forecast, identifying where new load additions are to be expected. This analysis of the community's projected growth helps target where infrastructure investments should be directed.

The spatial load forecast consists of six main steps:

Continued on Page 12

PacifiCorp Improvements
Continued from Page 10

- Determining load classes
- Building a land use model
- Identifying development parameters
- Developing load curves
- Calibrating the model
- Interpreting the results

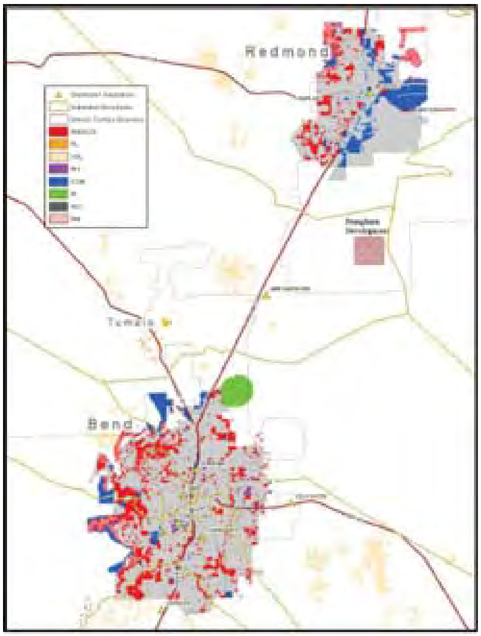
This results in a grid-based model that predicts the load contribution for each "cell" – for the Wasatch Front study, the service area was modeled to a cell resolution of one acre. The Wasatch Front model also studied the effect of conversion of older homes from swamp coolers (evaporative cooling systems) to centralized air conditioning (AC). This change in end-use characteristics has been a significant factor affecting distribution of new load across the area.

Since that first study, PacifiCorp has completed studies in the other growth areas. Each study has introduced new characteristics and challenges.

- The Bend, Oregon study introduced the team to urban growth boundaries, which has long been a feature of community planning in Oregon.
- The Medford, Oregon study included the impact of California retiree emigration, rapid growth in medical facilities and the effect of a proposed technology park.
- St. George/Cedar City, Utah and Park City, Utah were both smaller load areas with unique characteristics, such as load characteristics of snow machines and large vacation homes near ski resort areas.

Now that some years have passed since the first study, we are returning our focus to the beginning of this cycle. Plans are in place for a renewal of the Wasatch Front study in 2008. This time the study will include a comparison of actual conditions with forecasted results, to learn more about the validity of the model assumptions and the methodology.

One of the benefits of spatial forecasting is the high-resolution model of future service area load within the geographical information system. PacifiCorp has been able to repurpose this data to serve other business needs. One example is the development of new visualization techniques for communication with organizations outside the company.



Central Oregon Spatial Load Forecast

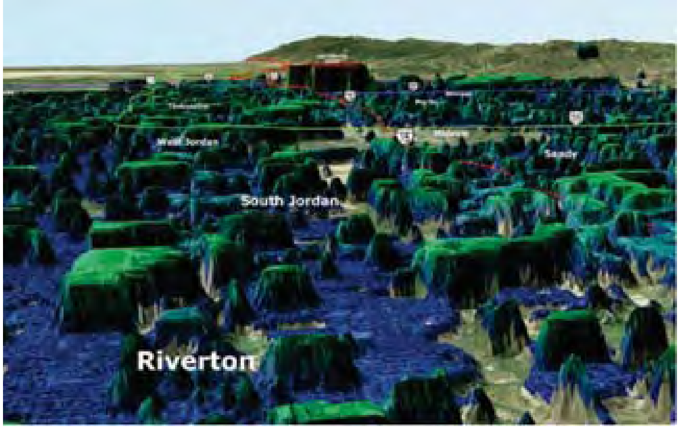
Rocky Mountain Power (PacifiCorp's operating company in Utah, Idaho and Wyoming) has had many discussions with the public utility commission about the growth rates and capital demands of the Wasatch Front. This discussion focuses on the causes of unusual load growth and the requirements for new generation, transmission, and distribution resources. Dialogue also takes place with legislative officials; for example, the Western Governor's Association sponsored an Energy Summit with many high-level leaders from the western U.S. in April 2007. PacifiCorp was able to repurpose the spatial demand model and create an animation of the long-term load growth trends in the Salt Lake Valley. The goal was to create a three-dimensional model that would show the changes over a 10-year period, more clearly depicting the reasons why new T&D infrastructure is required.

PacifiCorp worked with two outside vendors to research possible methods to achieve this.

Software tools included Google Earth, professional 3D modeling tools, and video animation tools. Rendering the final video animation required over 24 hours of rendering via parallel processing on seven multi-processor computers. A studio professional added a voice-over message to make this a truly effective public communication tool.

PacifiCorp joined a consortium of other utilities in 2006 to develop a new application for spatial forecasting. The application expands the methods discussed earlier to include new analytical approaches for distribution system analysis and load forecasting. PacifiCorp plans to immediately put this new


Wasatch Front 3D Model with Twelve-year Load Difference Applied



A View of the 3D Load Model during Fly-Over (looking north across Salt Lake Valley) application to use for an update of the Wasatch Front study, as well as to study several new areas of the service territories. Recent legislation in Oregon is expected to result in increased growth of demand-side resources, and this type of analysis is directly applicable for assessing such impacts.

PLANNING MODEL MAINTENANCE

The Planning Technologies department at PacifiCorp provides application and data support for engineers who plan T&D system reinforcements. These include the main grid and subtransmission area planning engineers, distribution engineers and operations support engineers. After the department was formed in November 2004, one highly ranked area of improvement related to the management of transmission planning models.

Transmission and subtransmission planning engineers use system modeling software to simulate future conditions on the transmission system. PacifiCorp engineers most often use a desktop software application from Siemens Power Technologies, Inc. (PTI PSS/E - Power System Simulation/Engineering) to construct these models, run load flow and stability analyses, and view results graphically. Software from other vendors (GE PSLF – Positive Sequence Load Flow – and PowerWorld Simulator) are also used, although PTI's product is used most often.

Operations engineers also use these tools to simulate real-time situations for day-to-day operation of the system (both main-grid and local dispatch).

To solve this problem, the project team took a business improvement approach. PacifiCorp's Business Improvement Methodology (PBIM) incorporates some Six Sigma and business process improvement techniques. After completing the first seven steps of the 13-step methodology, a number of inefficiencies and inaccuracies were identified. Over 150 separate study cases existed and there was no governing process by which cases were developed, or through which the genealogy of a particular case could be derived. This caused the planners to duplicate effort as they developed the model they needed. Certain detailed studies required that separate cases be combined - a lengthy, time-consuming, and error-prone process. In addition, the large number of interconnection points with neighboring utilities required integration of their system models, another point at which errors could easily be introduced.

The team developed a "To-Be" process that included the following elements.

• The data that makes up the system representation models will be stored in a single common data repository that can be integrated with a CIM-based architecture.

• Separately maintained models will no longer exist.

• Each portion of the Model data located in a common repository will be assigned a single individual or group responsible to ensure accuracy and continued maintenance.

• All parts of the model will be maintained by the individuals or groups that are most familiar with that portion.

• Future system changes will be tracked and included in the common repository as a queue of projects.

• Methods will exist to extract the projects that will form a model for a future case, based on individual needs.

• Given the required conditions, models will be easily and quickly generated, and tested to ensure that the case solves.

This analysis made it clear that software improvements would be required. After evaluating alternatives, the team selected a software application from Siemens-PTI called "Model on Demand" (now called MODweb). The team has installed this software, has loaded two system models (for Rocky Mountain Power and Pacific Power), and is configuring the system to support the new business process.

CONCLUSION

PacifiCorp can find some satisfaction in the improvements mentioned here. All these projects have benefited from a few key elements. These include an emphasis on business process improvement; reliance on standards such as the IEC TC57 Common Information Model; and solid project management practices. Much work remains, however. Future possibilities that are being considered include:

• Leveraging the OSIsoft PI infrastructure for better load modeling. PacifiCorp's transmission expansion plans, as well as other western U.S. activities, have increased expectations for load data. Transmission planners are more conducting more detailed studies of transmission flows, and the study schedules are more urgent.

• Integrating the SCHOOL PI system with SAP, to present planning and operations engineers with a clear view of operations and maintenance history for each asset.

• Synchronizing the operations model in the ABB Network Manager EMS with the planning models in MODweb. PacifiCorp participated in EPRI's CIM for Planning project this year to better understand and influence standards-based data exchange between these two environments.

STUDYING DIGITAL CONTROL SYSTEMS FOR HIGH-VOLTAGE SUBSTATIONS

By James Propst, Western Area Power Administration (WAPA); Mike Dood, Schweitzer Engineering Laboratories, Inc.

Western Area Power Administration markets and delivers reliable, cost-based hydroelectric power and related services within a 15-state region of the central and western U.S. and is one of four power marketing administrations within the U.S. Department of Energy whose role it is to market and transmit electricity from multi-use water projects. Western's transmission system carries electricity from 55 hydropower plants operated by the Bureau of Reclamation, U.S. Army Corps of Engineers, and the International Boundary and Water Commission. Together, these plants have a capacity of 10,600 megawatts.

Western started its automation projects with the goal of reducing the construction cost of new substations. Western estimated it could save 40 percent in building size and cost alone. Western also estimated similar savings could be realized in control panel costs with integrated digital controls.

Western began deploying programmable logic controller (PLC) control systems in 1996 with a pilot project at the Fort Thompson 230 kV yard. The pilot substation consisted of four 230 kV lines with a breaker-and-a-half bus arrangement. These initial designs replaced only the substation control wiring — no aspect of protection was included in the project. The PLC designs included an industrial computer running a Wonderware InTouch software application as the local operator's monitoring and control system human-machine interface (HMI). After modifications to the original design, the PLC design became the standard and was deployed in 20 substations across Western's service territory.

Western started looking at alternatives to the PLC design soon after these installations, and in 1998 they attended the open house and demonstration of the Philadelphia Electric Company (PECO) integrated system design. Meter and relay (M&R) mechanics at Western were not comfortable or confident with working on the PLCs and associated ladder logic, but they were comfortable working with microprocessor relays. Western also experienced PLC control failure associated with the use of the protocol interface to SCADA. Western felt that moving control functionality from the PLCs to a microprocessor relay and communications processor would address the reliability and comfort issues that the M&R employees had with PLCs. Eventually, Western chose the highly reliable combination of microprocessor relays and communications processors as their new digital control system (DCS) design to replace the PLC-based platform and chose to make Fort Thompson a pilot project. Once again, as was done with the PLC project years earlier, the pilot substation consisted of four 230 kV lines with a breaker-and-a-half bus arrangement.

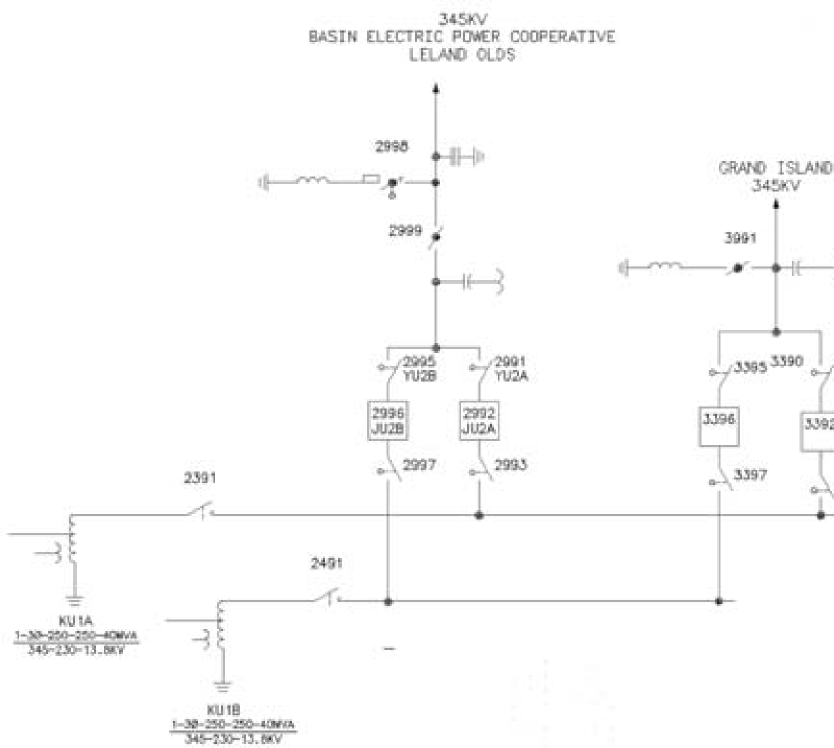


Figure 1 Fort Thompson 345 kV yard bus arrangement after Stage 06 modifications were completed. Four 345 kV circuit breakers, three 13.8 kV reactor breakers, eleven 345 kV MODs, and two 345 kV interrupters are under DCS control.

In the conversion from the PLC control system to the DCS design, Western also decided to include protective elements, or lockouts, in the DCS design. One lesson learned from the PLC design was that mixing digital and hardwired logic adds complexity to both portions. Because of the design and manufacturing processes, typical MTBF, and environmental ratings of PLCs, Western was not comfortable placing any protective functions in the PLC. Because the DCS would use protective relays for control, it seemed natural to have the lockout function reside there as well. Western chose a single dedicated microprocessor breaker failure relay as the “input” point to the DCS system. The outputs from the DCS system used contacts from the breaker failure relay and one of the line relays to provide a redundant control path for the power circuit breakers. Communications processors were used in the design to provide the interface to SCADA and the local HMI.

Although this initial DCS design was a step in the right direction, it was apparent that an additional iteration in the design would be required to provide enhanced economy and simplicity.

The next iteration was the use of fiber-optic cable to replace copper communications and the relocation of the DCS system inputs to be field I/O devices mounted near the station apparatus rather than duplicate the inputs with parallel copper wiring to the centralized IED. Thus, integrated digital communications allowed the I/O of the IEDs to be used for several functions within the DCS. A single 52a contact from the breaker auxiliary stack, wired to a remote I/O device, was used to provide this status for the entire system, including the protective functions.

Alarm points were wired only into the I/O device at the equipment, instead of also being separately wired to the control building and connected to an RTU.

PROJECT DEFINITION

Fort Thompson 345 kV Yard

Operations determined that the 345/230 kV transformers in the 345 kV yard should be separated from a common bus, creating a four-position ring bus configuration. This work required the addition of a 345 kV breaker and required modifying the bus work. The substation controls and relaying were largely original equipment from the 1960s. Western decided to replace the control panels because extensive wiring changes were needed to bring the substation up to current Western standards for SCADA.

The substation was built on expansive soils, which tend to move considerably, and which caused the foundation for the control building to crack in half. As the two halves settled, a three-inch crack developed in the wall, which had been covered with a steel plate to keep the birds out.

These problems made fixing the building impractical, so it was replaced with a modular, energy-efficient, low-maintenance building. The design of a DCS using integrated relays allowed the building to be over 40 percent smaller because integrated systems are much smaller than conventional PLC and RTU control designs.

The expansive soils over the years had created shifting in the control cable trays, causing the covers to have gaps. These gaps allowed rodents to enter the cable tray, causing substantial damage to control cable jackets. Unjacketed cable was eaten bare in many spots. The joint owner of the substation equipment agreed the control cable should also be replaced.

Fiber-Optic Cable

Fort Thompson, like most 345 kV substations, is a large substation. Cable lengths up to 1000 feet were to be replaced. At the time of this project, 12/C #10 shielded cable cost about $2/foot.

Because the project would require about 17,000 feet of 12/C cable, the use of fiber-optic cable was considered as an option. Western determined that they could replace the 17,000 feet of 12/C copper with 2,700 feet of fiber-optic cable. The cost of 24-fiber cable at the time of the project was $1.84/foot. This represented an upfront savings of $29,000, which would be spent on additional hardware requirements for the use of fiber-optic cable. The concept up front was to show fiber was competitive with copper in the substation.

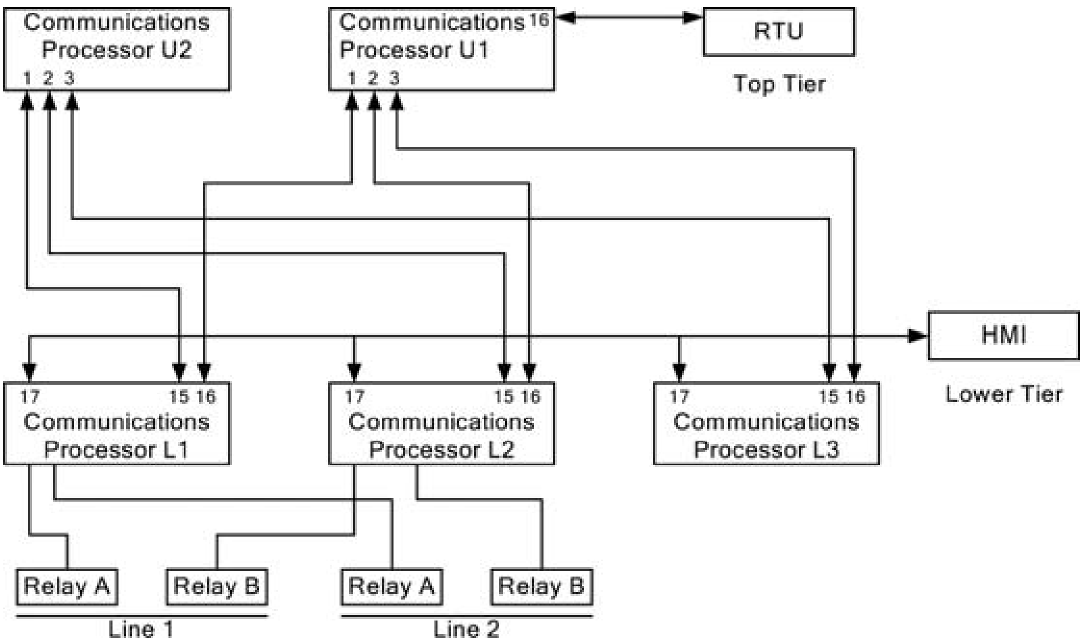


Figure 2 Communications Processor Architecture

The fiber-optic cable would be installed to each circuit breaker, transformer, and reactor. Motor-operated disconnect (MOD) controls and inputs would be wired over copper cable from the MOD to the associated circuit breaker where a remote I/O device would be installed to accommodate both MODs associated with the circuit breaker. At the transformers, alarms and trips from sudden pressure, winding temperature, and low oil would be connected to the remote I/O device and brought to the control house over fiber. Coupling the MOD and MOI controls with the major equipment would save fiber terminations. Considerable amount of copper cable would be saved because the MODs were close to the circuit breaker, eliminating up to a 1000 feet of 12/C for each MOD from the control house.

The use of fiber-optic cable would allow the digital inputs to be input into the DCS at the equipment. Western estimated that at least 75 percent of the DC wire terminations were eliminated. Consider that a cable must be terminated on each end, in this case to a terminal block in the building, then to a terminal block in the RTU, and finally to the RTU. This would all be replaced with a single switchboard wire at the individual piece of equipment.

About this same time, the logic processor became available on the market. This device allows the digital inputs to be distributed in real time among the relays and provides SOE (sequence-of-event) information for the RTU. The logic processor allowed a single 52a contact from the breaker to be distributed digitally over communications links to the primary relay, secondary relay, breaker failure relay, and the RTU. This further diminished the required wiring terminations.

The logic processor would also be used to create an extended digital protection system that tied all the individual pieces of equipment together to create an extended integrated protection system.

Because the logic processor would be used for SOE information, it needed to receive the digital relay operate event. This same piece of information would be sent to the breaker failure relay to initiate breaker failure. The use of the logic processor would eliminate the long block closing strings and breaker failure initiate wiring. All of this hardwired logic would be replaced with EIA-232 cables and settings.

Past Functionality

From the very first pilot project, Western had a high level of information flow with operations personnel, and they provided the manufacturer with feedback on their operational requirements.

Redundant controls were established as a requirement, as there was a concern about the ability to respond to and correct equipment failures with the new design. For the same reason, redundant HMI computers with redundant power supplies and hard drives running RAID 1 controllers were used. The new center of the system, the communications processor, had Modbus Plus protocol available, so Western's previous HMI design modules, also based on this protocol in the PLC, were used with very little modification.

Good Site

Fort Thompson was deemed a good site for this project, because it was relatively small. A total of 7 breakers and 13 switches would be placed under DCS control. This would require fiber to be installed to 11 pieces of equipment — a very manageable number. The physical size of the yard made the fiber attractive, because a lot of copper cable could be elimi-

Figure 3 The I/O device on the right provides open and close commands for the MODs. It also provides the 43LR, 52a, and 52b status to the DCS. The I/O device on the left provides inputs into the DCS for the individual power circuit breakers. Note the extra fiber-optic cable, which allowed terminations to be completed in a mobile van and provided additional cable for when the power circuit breaker is replaced.

nated. And, finally, the project had strong support from Western's Communications division, which installed and terminated the fiber-optic cable.

THE DCS DESIGN

Controls

Western operations personnel wanted the ability to trip and close a circuit breaker in the event of equipment failure. Therefore, Western designed redundant controls as a standard part of the automation design to eliminate single points of failure. The redundant control paths were accomplished using a two-tiered communications processor approach. The top-tier communications processor receives the SCADA command and distributes it via global data over the Modbus Plus network to the lower-tier communications processor. This creates a single point of failure for SCADA with the top-tier communications processor, but with an MTBF of greater than 200 years, this risk was accepted and is far better than single or redundant RTUs.

From the lower-tier communications processors, controls were passed to the individual protective relays. From the protective relays, positive, negative, trip 1, trip 2, and close were hardwired with a 5/C to the circuit breaker. Most circuit breaker protective trips were hardwired from the protective relays. Some of the bus protection trips were accomplished with relay-to-relay communication via the logic processor. In this design, the Set A protective relay and individual breaker failure relay provided the redundant control paths for the 345 kV circuit breakers. The individual breaker failure relay also

Continued on Page 42

GENUINE

Scepter®

REEL DEAL

TIME SYNCHRONIZATION IS CRITICAL FOR SUBSTATION AUTOMATION

By Bruce A. Muschlitz, EnerNex Corporation; Gary M. Nelson, AREVA T&D

Time synchronization is a basic function common to all automation systems. The accuracy and resolution of event timestamps can be a deciding factor in the success of an automation project.

The new standard for substation communication, IEC 61850, specifies that SNTP (Simple Network Time Protocol) is one of the mandatory synchronization mechanisms.

The availability of SNTP in source code form induces many IED vendors to implement SNTP almost as an afterthought. However, off-the-shelf implementations are seldom optimized for accuracy and typically provide only a few tens of milliseconds of synchronization potential.

There is a better way. Through careful attention to detail, time synchronization on the order of microseconds is achievable using commonly available hardware and software. This article will show how standard off-the-shelf PCs, running the standard Windows XP operating system, can achieve orders of magnitude improvements over simple implementations.

The motivation for this research is to demonstrate that the default time synchronization protocol chosen for IEC 61850 is indeed adequate for substation usage. It will be shown that the assumption that SNTP is only accurate enough for low accuracy timestamps is a false "urban legend".

BACKGROUND

The task of time alignment between devices is more complicated than simple time synchronization. The frequency offsets between devices can be a significant source of time error even if synchronization is perfect. As an example, typical crystal oscillators can have offsets of up to 0.005% (50 Parts Per Million). If time synchronization is performed every minute with perfect accuracy, then the time error can be up to 60*50 = 3,000 microseconds. If accuracy of a few microseconds is desired, it is obvious that simple time synchronization will not achieve the goal.

Two terms will be used throughout this document:

- Syntonization – the creation of a common rate of time flow (i.e. frequency calibration)
- Synchronization – the creation of a common tie epoch (i.e. time offset calibration)

Both of these terms need to be considered if accurate clocks are required.

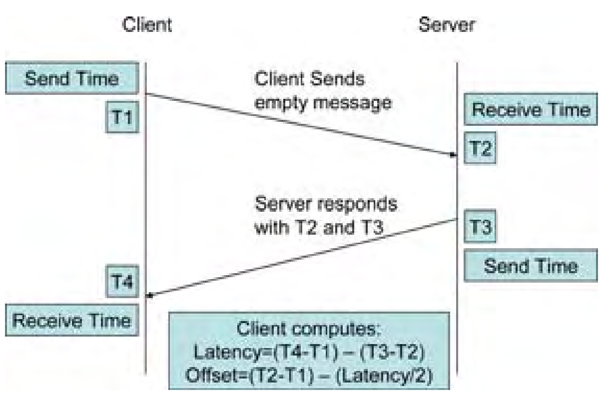


Figure 1 - SNTP protocol

TIMESTAMPING USING WINDOWS XP

Windows system services are known as Application Program Interfaces (APIs) and are executed as simple function (subroutine) calls from application programs. Off-the-shelf PCs maintain "PC time" by signaling overflows of a hardware counter which is incremented at a rate greater than 1 megahertz. The Windows XP operating system increments the "PC time" [returned by the "GetSystemTime( )" function] by the time interval between rollovers when the hardware signals the rollover. The counter overflow typically occurs at intervals of 10-15 milliseconds.

Windows does provide an alternative mechanism which returns a timestamp with 100 nanosecond resolution, "GetSystemTimeAsFileTime( )". However, a bit of reverse engineering shows that this time is actually the basis for "GetSystemTime( )" and has exactly the same effective time resolution. The reason for the low resolution is that the time value is incremented in large steps during the counter overflow interrupt function.

Finally, it should be noted that the Windows operating system also provides a mechanism for indicating the total number of accumulated counts of the hardware counter through the QueryPerformanceCounter( ) function call. QueryPerformanceCounter( ) is a critical component for high accuracy time synchronization.

TIME SYNCHRONIZATION PROTOCOLS

There are four good candidates for clock synchronization:

- IRIG-B
- UCA2
- IEEE 1588
- SNTP

IRIG-B is commonly used as the output format of Global Positioning System (GPS) clocks. It provides a simple clock capable of accuracies of better than 10 microseconds and the time is updated by the server once every second. Unfortunately, there is no (standard) method to distribute the signal over an Ethernet network.

UCA2 time synchronization was developed by the Electric Power Research Institute (EPRI) for use with the predecessor of IEC 61850. The protocol runs over Ethernet Local Area Networks (LANs) and is capable of accuracies of fewer than 50 microseconds. Like IRIG-B, the server controls the issuance of the time synchronization events.

IEEE 1588 is a complex protocol

that was developed for process control systems and achieves accuracies of fewer than 20 microseconds (without "hardware assists"). Unlike IRIG-B and UCA2, the synchronization requests are issued by each client. One form of IEEE 1588 protocol runs over standard Ethernet LANs.

SNTP is a simple protocol developed by the Internet Engineering Task Force (IETF) for simple time synchronization applications. It provides accuracies of better than 100 microseconds over Ethernet LANs. Synchronization requests are issued by each client. This is the default time synchronization used by both Microsoft Windows XP and IEC 61850.

THE SNTP PROTOCOL

SNTP operation can be easily explained. The device requesting synchronization (the Client), formats a request data packet and sends this to the synchronization Server at time T1. The server records the reception time, T2, and transmits a response data packet at time T3 containing time values for both T2 and T3. Finally, the client receives this packet at time T4 and decodes the other two times contained in the packet. The four times are used to compute estimates of both the end-to-end network latency and the offset between the clocks. Figure 1 demonstrates the protocol.

SNTP PROBLEMS

SNTP is such a simple protocol that it is difficult to imagine errors resulting from SNTP use. However, the simplicity of SNTP hides the fact that real devices behave very differently from the ideal devices defined by the above equations.

One problem is that real devices have finite resolutions for each of the four timestamps. This causes rounding errors to be introduced into the calculations. These errors, also known as quantization noise, occur on both the client and server and cause uncertainties related to the sum of these errors.

Another problem occurs due to the arithmetic precision of the calculations. The timestamps used by SNTP use unsigned 64-bit quantities with the most significant bit set. The conversion of these values into conveniently computable floating-point values causes a loss of required precision.

Simply stated, conversion of the values into double precision floating point (64-bit) values will immediately reduce the accuracy to the level of a few microseconds. Single precision floating point (32-bit) conversion results in many minutes of error.

The production of the timestamps provides yet another source of inaccuracy. The software can have varying execution delays between the time that a timestamp is requested and the time the value is provided. These delays add uncertainty to the value of the timestamp.

There are additional sources of varying software latencies as outlined below:

- SNTP assumes that the packet transmission times (T1 and T3) can be accurately estimated. Although this assumption works well when millisecond accuracies are desired, sometimes packet transmissions are delayed for many microseconds for a variety of reasons.
- SNTP assumes that the packet

reception times (T2 and T4) can be accurately estimated. These times, like the transmission times, are subject to uncontrolled microsecond-level delays. The most unpredictable delay is the time between the complete packet reception and the signaling of the software driver. This is better known as interrupt latency. This effect can cause hundreds of microseconds of inaccuracy for a single packet reception.

• The Windows XP operating system (OS) itself can strongly affect the behavior of the SNTP execution. For example, the SNTP "task" can be pre-empted by a higher priority task at any time. If that happens between the time of an event and the time of a timestamp request, then significant errors are introduced.

• The OS can produce uneven rates of time flow in an attempt to "correct" the rate of time flow. For example, the OS can add or subtract values on 1-second intervals corresponding to internally estimated time rate errors occurring during each second. If the SNTP exchange overlaps one of these 1-second boundaries, then the relationship between timestamps on each side of this boundary become unclear.

• The network devices comprising the Ethernet LAN can introduce uncontrolled random time delays due to queuing which occurs on each physical Ethernet port. These delays can be tens of microseconds in duration.

• SNTP assumes that the network latency in each direction (toward and away from the Client) is identical. SNTP assumes that exactly one-half of the estimated end-to-end latency can be attributed to each direction. This assumption can be violated if packets can traverse different paths in a redundant network or if one direction of the SNTP exchange is delayed.

To summarize, the aforementioned effects cause each individual SNTP transaction to be subject to an unknown amount of timing "noise". However, many of these noise sources occur relatively infrequently. This infrequency of errors is a key to an accurate time synchronization system.

PEELING THE ONION

The creation of an accurate time synchronization system requires the removal of many error sources. The approach taken in this paper is best described as "peeling the onion". Just as an onion has many layers between the original surface and the core, time synchronization presents many challenges that must be solved one layer at a time. The basic approach will be to begin with the simplest possible implementation and then solve problems one at a time.

All of the software used for this synchronization system was created in the "C" programming language using direct calls into the operating system for the basic services. A great deal of caution was used to ensure that the measurement probes introduce as little error as possible. The programs were executed as "console applications" at relatively high task priorities. All of the accompanying plots display the relative time of the synchronization exchange on the "X" axis and the estimated time offset on the "Y" axis except where noted. Synchronization attempts were executed by "Sleep"ing for a fixed time and then synchronizing.

SIMPLEST POSSIBLE CLIENT AND SERVER

The simplest possible system uses the GetSystemTimeAsFileTime( ) Windows API call to retrieve the time at appropriate points. Unlike most other plots, the "X" axis of this plot indicates the sample index rather than the time of the sample (for reasons which will become apparent).

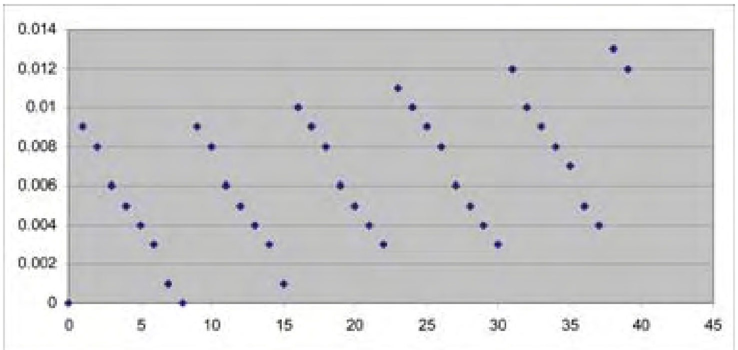


Figure 2 - Simplest Client, Simplest Server

Refer to Figure 2 for the data.

The plot shows that this time synchronization is completely unusable for high accuracy synchronization. Random errors at the 10 millisecond level can be seen. These errors are large enough that it does not make sense to display the estimated time of the synchronization exchange.

Careful inspection of the raw timestamps reveals that the interval between timestamps is always fixed. Investigation shows that the main problem is usage of the Windows API function, "GetSystemTimeAsFileTime". This Windows "Application Program Interface" (API) returns a time value with resolution to 10-7 second. However, Windows XP rounds this value to the nearest interval of 10 or 15 milliseconds (hardware dependent). This represents the level of performance of the default Windows synchronization mechanism. The first layer of the onion to peel will be a revision to the Client program to use timestamp value with a much higher effective resolution than 10-15 milliseconds.

IMPROVED CLIENT – USE HIGHER RESOLUTION TIMESTAMPS

This step replaces the "GetSystemTimeAsFileTime" with the "QueryPerformanceCounter" (QPC) mechanism. The QPC mechanism, however, has no direct relationship with the base windows real-time clock and therefore must be calibrated. The calibration procedure is:

• Record the total count (QPC value) just after Windows real-time clock indicates that a one-second boundary has occurred. This count will be referred to as "C_CAL".

• Record the "real time" after this one second boundary. It corresponds to an exact one-second boundary. This will be referred to as "T_CAL".

• Record the rate of counter increment (using the API "QueryPerformanceFrequency"). This will be referred to as "R_CAL".

When a timestamp is needed, request the present counter value from "QueryPerformanceCounter". This count will be called "C_PRESENT". The present time is then computed by the following:

$$(n^*\Sigma(X^2)) - (\Sigma (X))^2$$

Equation 1 - Calculation of a high-resolution timestamp

Using this revised timestamp mechanism in the Client program, the graph in Figure 3 was obtained. Note that the "X" axis again indicates the sample index rather than the actual time.

The data shows a significant improvement over the previous data. Note that the "random" time errors are now only about 6 milliseconds with a few outliers (these outliers are artifacts of the Windows operating system). This appears to show that the approach is valid. The next step is updating the server to use the new timestamping procedure.

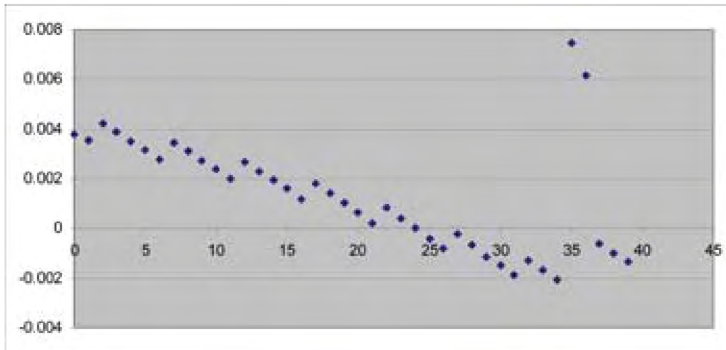


Figure 3 - Improved Resolution Client

IMPROVED SERVER – USING HIGHER RESOLUTION TIMESTAMPS

This is an easy step: the improved Client code is simply ported to the Server code. This revision produces data that mandates recording of (the start of) the actual synchronization exchange. In order to clarify the data, the "X" axis now indicates the actual time offset of each exchange from the first exchange. Figure 4 illustrates the recorded data.

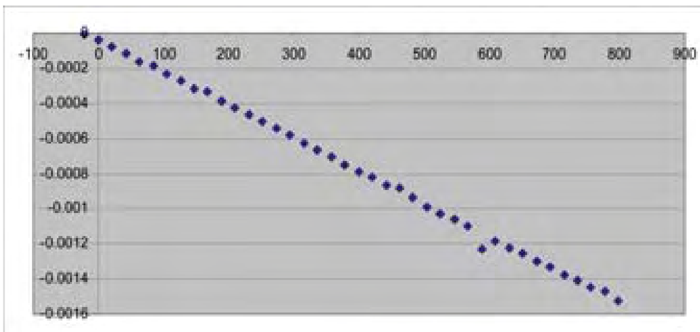


Figure 4 - High Resolution Client and Server

Now there is a definite pattern. The time offsets clearly change linearly with the sample time. In fact, the slope of the line indicates the frequency error between the Client and Server. Note also that the uncertainty (after slope removal) is on the order of about 20 microseconds. This can be seen more easily by performing a linear least-squares curve fit to the data and plotting the differences between the computed line and the actual point. The results are show in Figure 5.

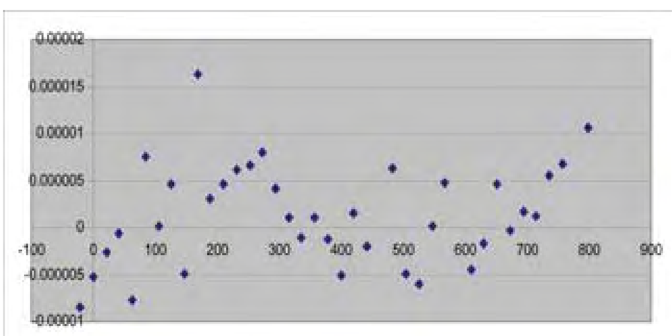


Figure 5 - Residual after linear fit

Note that the graph scale has been adjusted and the point at 588 seconds is literally "off the bottom of the chart".

It appears that we could use this linear relationship to calibrate the clocks. The slope could be used to syntonize the clocks, while the intercept point could be used to synchronize the clocks at the most recent SNTP exchange.

A few problems remain before we can use these data points. There is noise in the data that could be removed. Experience has shown that when operating on a lightly loaded Ethernet LAN, "many" of the points are very accurate and some points are outliers. The problem of outlier detection is the next step.

"It can be shown" that points with the highest latency are most likely to contain the most noise.

SNTP provides an estimate of end-to-end latency for each message exchange. Removal of the points with the largest latencies will result in a reduction in noise. One measure of this noise is the correlation coefficient of the linear least squared fit. This value (R-Squared), ranging from 0 to 1, indicates the degree of fit to a straight line. The raw data has an R2 value of 0.9986. After removal of the samples with the 20% largest latencies, the R2 value rises to 0.99990.

The data still contains noise unrelated to measured network delays. To remove this noise, points that do not fit the linear model must be removed. The following procedure removes these points:

• Compute a least-squares linear fit to the points

• Locate the point which is "furthest" from the predicted line (i.e. has the largest residual)

• Remove this point

• Repeat the procedure until "enough" points have been removed

This is a computationally difficult problem due to the required precision in the calculations. It is very easy to lose precision when using double precision floating point values on the SNTP timestamp value. The suggested procedure is to offset each of the timestamps by the same fixed amount resulting in an offsetted value nearer to zero. This provides about another 23 bits of "headroom" in the floating point calculations. The most sensitive part of the least-squares curve fit is the calculation:

Now = T_CAL + [(C_PRESENT – C_CAL) * R_CAL]

This calculation has the surprising property: for equally spaced points, the value is dependent only upon the number of points and the spacing and NOT upon the value of each X point.

It has been empirically determined that removal of 20% of the points through this procedure results in a very good fit to a straight line. Using the above data, the R2 value is increased to 0.99995. Care must be taken to ensure that enough points remain to have significance to the time synchronization operation. Up to this point, 40% of the points have been removed leaving 60% of the original points. The resulting data is shown in Figure 6.

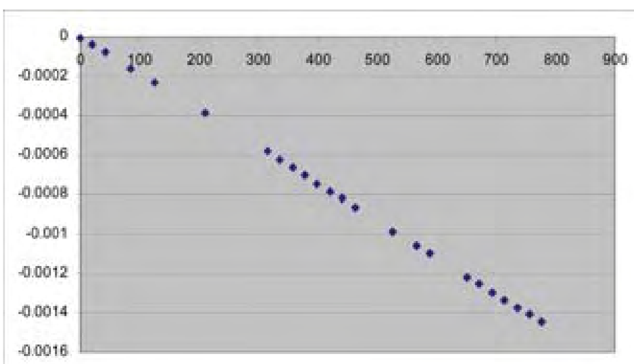


Figure 6 - After removal of high latency and "bad fit" points

The result after this manipulation is an extremely precise fit of the points to a straight line. This particular data shows a syntonization error of 1800 * 10-9 relative error (1800 Parts-Per-Billion).

The effective synchronization error at a future time can also be computed. These corrections can be used to modify the "constants" in the calculation of Equation 1. The slope of the line is used to adjust R_CAL and the intercept point is used to modify C_CAL.

RECALIBRATING THE HIGH-RESOLUTION TIMESTAMP

The recalibration procedure for the timestamp calculation in Equation 1 seems straightforward.

The syntonizing recalibration of R_CAL, however, causes the timestamps produced just after the modification to differ drastically from timestamps before the modification. A small bit of algebra shows that C_CAL must be changed so that the calculated timestamps after syntonization agree with those just before the modification of R_CAL.

The recalibration for offset (synchronization) is very straightforward and involves modification of the C_CAL value in an obvious way. This completes the syntonization and synchronization of the Client.

A quick check of subsequent SNTP exchanges shows that there is a rather large time offset of a few dozen microseconds between the Client and Server. However, the frequency offset is very near zero. An inspection of the initial assumptions reveals the problem: it was assumed that the Client sample times were accurate, but they were drifting due to syntonization errors. There are two ways of correcting for this problem:

• Review all of the mathematics and try to remove this second order frequency error effect

• Rerun the algorithm using a syntonized Client

The second route is chosen because it allows complete verification of the algorithm.

SECOND-PASS EXECUTION OF THE ALGORITHM

The entire algorithm is repeated. As a first step, the raw samples are verified to ensure that no systematic errors have been introduced. The data is shown in Figure 7:

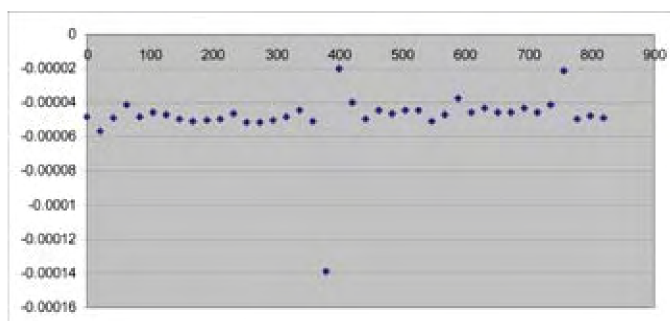


Figure 7 - Pass 2 Raw Data

This data shows that offsets are clustered around 50 microseconds of error with no discernible frequency offset. The outliers are still present with a few at +30 microseconds from the cluster and one at -90 microseconds from the cluster. After removal of the points with large latencies and points "off-the-curve", the data in Figure 8 is obtained.

This data looks terrible at first glance. In fact, it shows that all systematic errors have been removed and only a small amount of noise remains. The frequency error resulting from a linear fit is 1.4 * 10-9 relative error. Contrast this with pass 1 value of 1800 * 10-9 relative error. Also note that after 800 sec-

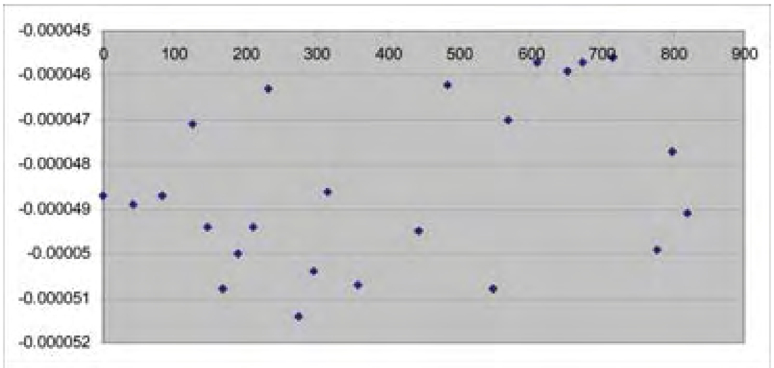


Figure 8 - Filtered Pass 2 data

onds, the uncertainties are only a few microseconds, a maximum of 4 microseconds, and an RMS error of 1.9 microseconds.

A THIRD PASS THROUGH THE ALGORITHM?

Experiments have shown that no further accuracy improvements occur when additional passes are executed. It should be obvious that all errors at this point are at the noise level. As a verification of the results after pass 2, the Client executed a delay of approximately 5 minutes and then executed 2 SNTP exchanges. The first exchange produced a synchronization error of 94 microseconds and an exchange one second after that produced an error of 5 microseconds.

The 94 microseconds of error could be explained by the fact that each PC had completely removed the Client and Server programs from cache memories. This caused unpredictable startup delays. The second SNTP exchange executed after the cache memories were refreshed and showed that synchronization was maintained after 5 minutes with only 5 microseconds of error. Although part of this error is measurement noise, a maximum syntonization error of 16 parts-per-billion is demonstrated.

WHAT'S LEFT

This paper has shown that it is possible to syntonize and synchronize off-the-shelf computers running off-the-shelf operating systems. Synchronization accuracies suitable for almost any substation application can be achieved.

Some details of the implementation have been left incomplete on both the Server and Client side.

Each of the details would need to be further explored for a production system.

One annoying source of error is the tendency of the operating system to move rarely executed code out of cache memory and therefore significantly impact the code execution times. This can be partly solved by executing the SNTP synchronization exchanges 2 times and ignoring the first exchange.

SERVER SIDE ISSUES

On the Server side, the Windows time source was assumed correct. In real systems, however, an external time source would be used.

This requires that the QueryPerformanceCounter synchronization use the external clock. This would be relatively easy to accomplish. More difficult would be to syntonize the R_CAL value with the external clock. This could be accomplished by performing two widely spaced external clock synchronizations and noting the average rate of advancement of the QueryPerformanceCounter value.

A related issue with the Server external clock is the validation of the timestamps with respect to the external clock. Ideally, there would be a method for the external one-pulse-per-second (1PPS) signal to create its own timestamp (perhaps by feeding back into a serial or parallel port on the PC). This, however, might be inadequate for high accuracy timestamping due to port hardware signal conditioning and interrupt latencies within the PC. This verification might require some "real engineering".

The final server issue is the systematic delays in various portions of the hardware and operating system. For example, the code to call the timestamping procedure requires a finite amount of time to execute. These predictable "fudge factors" should be built into the synchronization software (note that this does not directly affect syntonization). Example of these "fudge factors" include:

- The delay from the software requesting a packet transmission until the packet is placed on the Ethernet wire
- The delay from a received packet end until the software is signaled of its reception

CLIENT SIDE ISSUES

The client side of the synchronization has fewer problems than the server side. It shares the requirements for the "fudge factors" as well as the requirement for accurate measurement of the desired events (on the server side, only the timing of network events was critical).

SYSTEM ISSUES

The system is not complete until end-to-end testing has been performed. The best way to accomplish this testing is to have the server's external source create a stimulus which can be timed by the client. Another method which has proven successful is to have the client toggle a physical output a short time prior to the external clock's 1-pulse-per-second signal. For example, an output could be toggled 10 microseconds prior to the one-second boundary and an inexpensive oscilloscope could be used to verify the resulting timing relationship. It is important to do this prior to the one second boundary because the operating system executes many operations at one second intervals.

One problem that has not been addressed is the fact that the crystal oscillators within the PCs are very sensitive to temperature changes. Typical crystal oscillator frequency sensitivities are about 1 part-per-million per degree (Celsius). All of the test runs for this paper have been made in a room with a nearly constant temperature.

EXTENSION TO NON-PC PLATFORMS

The techniques outlined in this paper are applicable to hardware and software platforms that differ substantially from PCs. The only timer requirement is for a high-resolution monotonically increasing timer. Most embedded devices can satisfy this requirement by counting the number of "tick interrupts" and then computing the number of counts until the next scheduled interrupt.

3M COLDSHRINK TECHNOLOGY TURNS 40 YEARS OLD

3M is celebrating the 40th anniversary of developing cold shrink technology. These specially formulated rubber tubes, stretched on a removable core, are used for electrical insulation, splicing and terminating. Since no sources of heat or extra tools are required to install this accessory, 3M gave the name "cold shrink" to the new technology.

"We were looking for a simpler, better way to insulate in-line splices for electrical power cables," recalls Jim Sievert, the 3M engineer who first conceived the cold shrink idea. He spent many months in material and process development with a team of associates at the company's St. Paul, Minn., laboratories. They overcame a number of technical challenges to eventually bring the idea to the market in the first of an ongoing series of products.

Ethylene propylene diene monomer (EPDM) rubber, a relatively new material in 1968, offered promise for the cold shrink idea. An EPDM rubber formulation was needed that would easily stretch onto a core and when installed, would provide continuous radial pressure to maintain an environmental seal. 3M engineers developed a new formulation of EPDM rubber that would provide this "living seal."

"The Canadian energy market has changed significantly in the past forty years," explains John Kosnik, executive director, electrocommunications business, 3M Canada. "As energy demands continue to increase, 3M is prepared to meet the needs of its customers largely due to advancements in and new applications of shrink tube technology."

The first application for the cold shrink insulation product (initially

An underground in-line splice connection (above) for Manitoba Hydro, and an above-ground installation for the same utility (top left). At the bottom left, a medium-voltage termination using the cold-shrink 3M technology.

known as the Pre-Stretched Tube or PST) was for buried low-voltage secondary splices. Over four decades, 3M has used this technology as the basis for continued innovation:

· The first step in the evolution of 3M cold shrink technology was the 3M termination QTM for medium-voltage applications.

· The 3M Cold Shrink Termination QT-II for medium-voltage terminations, consisting of a silicone insulator with integrated Hi-K stress relief, was introduced in the late 1970s.

· In 1993, the 3M Cold Shrink QS2000 was the first cold shrink medium-voltage splice introduced in Europe.

· A further development in 1996, the 3M Cold Shrink Termination QT-III, eliminated the need for grease, reduced the effective length of the termination and increased arc and track resistance. The QT-III insulator ended the need for sealing the top of the termination with tape, and provided improved hydrophobic recovery.

· In 1997, Cold Shrink Splices QS-III for medium-voltage cable were added to the line. This one-piece design incorporates an under-cut electrode to control electrical stress within the splice.

· Cold shrink branch splices for medium-voltage cables were added in 2001.

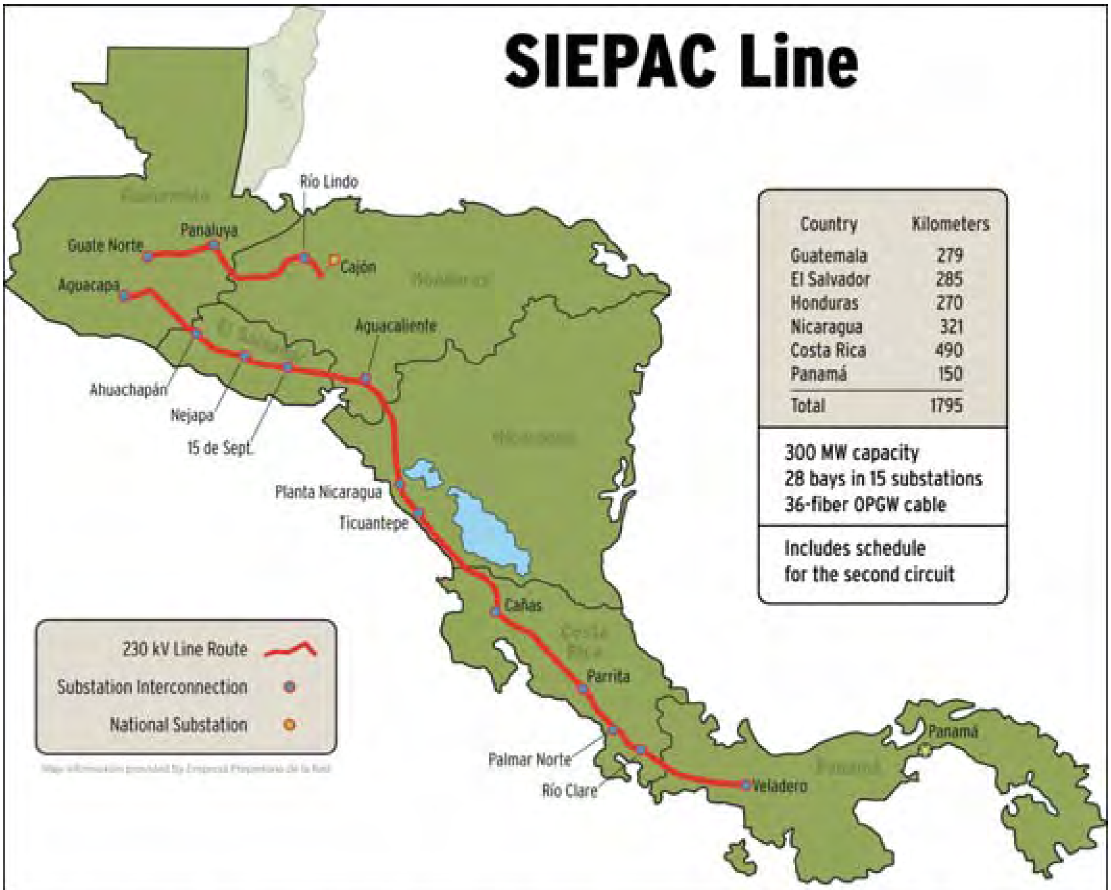
· 3M introduced cold shrink terminations for aerial and pad-mounted 69kV applications in 2005. The 3M Cold Shrink Termination Kit QT-III for 69/72,5kV replaces heavy porcelain products and heat shrink terminations. Users report that cold shrink terminations for high-voltage applications are compact and easier to handle than traditional systems and are installed in substantially less time and with greater safety.

· Additional cold shrink products for low-, medium- and high-voltage applications will be introduced in 2008.

COLD SHRINK IN CANADA

In 2003, Manitoba Hydro required an entirely new product: high-voltage 69kv terminations that were as efficient to apply as medium-voltage cold shrink terminations. With the combined efforts of 3M Austin to manufacture the product and 3M Canada's marketing and technical team, 3M met the customer's need. 3M launched the product in 2005 and it continues to sell well in Canada. Cold shrink applications are used by companies nationwide.

NEW TRANSMISSION INTERCONNECTION REDUCES CONSUMER COSTS



Schweitzer Engineering Laboratories has teamed with Techint for the SIEPAC project, a 1,830-kilometre transmission system spanning Central America.

Schweitzer Engineering Laboratories, Inc. (SEL) has been selected to provide protection, control, and automation systems for the SIEPAC (Sistema de Interconexión Eléctrica Para América Central), or Central American Electric Interconnection System.

The project will construct a 1,830-kilometer, 230 kV transmission system linking Guatemala, El Salvador, Honduras, Costa Rica, Nicaragua, and Panama. SEL has teamed with Techint, the engineering and construction company awarded the general construction contract.

The new transmission system interconnection will alleviate the region's periodic power shortages and decrease operating costs, thereby reducing the cost of electricity to consumers. Empresa Propietaria de la Red (EPR) administers the project.

Estimated to cost US$370 million, the system will serve more than 37 million customers in Central America.

The 1,137-mile transmission system includes 15 substations. SEL will manufacture the electronic equipment in Pullman, Washington, and ship it to the SEL panel manufacturing plant in Monterey, Mexico, for assembly and testing. SEL will also manufacture the panels at the Monterey plant.

SEL will provide the main line protection using SEL-421 High-Speed Line Protection, Automation, and Control Systems and SEL-311L Line Current Differential Systems with MIRRORED BITS communications for teleprotection schemes.

SEL-2407 Satellite-Synchronized Clocks will time-synchronize all substations to within 100 nanoseconds. SEL-451 Protection, Automation, and Control Systems will oversee bay control, working together with SEL-3332 Intelligent Servers to concentrate data and provide connectivity for SCADA and station integration.

All devices include IEC 61850 for future integration and connectivity.

SEL expects to deliver the first panels in November 2008, with the final shipments made by March 2009. The new transmission system is scheduled to operate by mid-2009.

WINDS OF CHANGE BLOW CONSULTING GROUP TO HENDRIX

The winds of change have been blowing at Consulting Engineers Group (CEG) for the past five years. And ironically, these winds have brought… wind.

CEG is a wholly owned subsidiary of Dakota Electric Association that provides high-quality, high-tech transmission and distribution engineering to the utility market. CEG has turned its attention to the burgeoning wind power market in the past five years – more particularly, design and build work for wind farms.

"It is far and away our biggest area of growth," says Vince Granquist, a vice president and senior project engineer with the Farmington, Minnesota based firm. "At this point, it is probably over 75 percent of the company's focus."

But why wind farms?

"I happened to see that a wind turbine was planned for Carleton College, a private, liberal arts college in Northfield, Minnesota," Granquist goes on. "I live in Northfield and know all these people. Once we got interested in that project, it kind of snowballed as we talked to other people building other small wind-related projects in Southwestern Minnesota."

Once CEG began its journey down the wind farm road, it gained valuable expertise that could only be acquired through firsthand experience. A key find of CEG engineers is that designing and installing collection systems, including the 35kV cable portion, and the substations and transmission line work that accompanies it, is one of the most critical aspects of a wind farm project. To support this function, CEG purchases hundreds of thousands of feet of 35kV TRXLP, underground cable. Although the cable is a critical component of the system, it is a standard utility product that is used to connect the turbines, both to each other and back to the substation.

Given that this cable is viewed as a commodity, there are numerous reputable suppliers capable of providing a reliable product; regardless of whether the end product is a cutting-edge wind farm or a traditional electric facility, the standard utility cable will do the trick. But how does a company determine which supplier is best? One thing that Granquist knows for certain: while pricing is important, it is by no means a "make-or-break" purchasing parameter.

"Certainly, you're always looking for the best price possible to lower total project cost," he says. "For a typical 100-megawatt wind-farm, you can be talking about a million dollars worth of underground cable, so the pricing difference between two suppliers can be noticeable."

"On the other hand, for a 100-megawatt wind farm, there's going to be about eight million dollars in total electrical work, so the decision is not entirely price-sensitive.

The level of service matters much more than another tenth of a cent reduction in product price."

Back in 2005, a time in which CEG was relatively satisfied with its cable supplier, Granquist became familiar with Hendrix Wire & Cable based in Milford, NH. Hendrix's local representative, Chuck Healy of ElectroTech Inc., a Minneapolis-based firm, began talking with CEG, asking that they listen to what Hendrix had to offer. Feeling that Hendrix might be a good fit with CEG, Granquist agreed; after all, Hendrix had offered competitive pricing for CEG's wind farm applications, as well as management for all the delivery and scheduling issues.

Discussions with Hendrix left CEG pleased with the quality and pricing of Hendrix's 35kV cable. What's more, Hendrix was excited about the prospect of bringing on another wind-farm customer. The first purchase order from CEG came in June 2006.

While the relationship between the two companies moved forward smoothly, Granquist soon learned what truly separated a good vendor from a great vendor in this industry. The difference lies in the value-added services offered by the vendor to back up the product, as well as the unique delivery requirements of the wind farm industry.

To that end, Hendrix introduced two additional services to CEG during the second year of the relationship that truly sealed Hendrix's status as a valued CEG partner; "Bill and Hold" and "Capacity Planning."

Bill and Hold, quite simply, is a means of adjusting for the uncertainty in project lead times versus cable lead times. "Hendrix builds the cable based on the scheduling needs of a given project. Then the company holds the cable on site, free-of-charge for an agreed upon time frame. This program has provided CEG the certainty of cable availability combined with the flexibility to react to unplanned events," says Granquist.

This option gives CEG the ability to work within its clients' production schedules, which are often erratic at best, by providing what is essentially "just in time" delivery of the cable to the jobsite when the time is right – not just in terms of actual installation but ensuring that someone is at the site to take delivery.

"Cable manufacturing will consume a fixed amount of plant production time from when you issue a purchase order," Granquist explained. "You usually issue a purchase order with a notice to proceed contract, but without necessarily having everything nailed down as to when work will begin at the site. It becomes necessary to get the cable on order with the distinct possibility that even though the cable is ready, the site won't actually be available until the following month. In some cases, the delay may be as much as two months."

The typical process would call for the vendor to manufacture the cable and deliver it to the jobsite, despite the fact that the site might be unprepared and be nothing but a corn-

The explosion of wind farms has meant an increased demand for cable.

field. This would require companies like CEG to make alternative storage arrangements. Further, it means locating someone with equipment capable of unloading and moving thousands of pounds of cable. In this case, the cable could sit for a month or more at the jobsite, with no one to watch over it, exposing it to damage or theft.

"Delivering the cable directly to CEG in Farmington would be a possibility, but it would have to be moved a second time to the job site. Few people want to pick up and handle cable twice, incurring further cost," adds Granquist.

Capacity Planning is another service that provides CEG a greater measure of control over the sometimes uncontrollable scheduling of wind farm projects. This option provides CEG with access to the Hendrix production schedule on a regular basis, allowing CEG to modify items and quantities to respond to multiple wind projects in development.

"If I suspect that a few projects are likely to be released over the course of the summer and fall, I can work out what I think might be the basic cable order, even if the projects aren't definite," says Granquist. "I can say to Hendrix, 'From a capacity planning point of view, plan on taking up a couple of slots in late July to deliver cable to me in early August, and I will confirm it on June 1.' That way, Hendrix can have an idea of what CEG needs for possible production. In the event that one of those slots doesn't work out, we have at least established a 'fish-or-cut-bait' date so that it doesn't become an economic problem for Hendrix".

"Essentially, we needed a procedure to address the fact that we know we're going to do something but frankly, until people stop moving turbines and tell us to go ahead, we don't know exactly what. So, a vendor with flexibility in terms of how we fit things through their system and get it out the other side is extremely useful."

These two programs, along with the consistent quality of the cable and the ability to produce specific lengths (with virtually no overage costs) have helped Hendrix and CEG forge a mutually beneficial partnership. Hendrix's knowledge of the wind farm market and the challenges faced on the jobsite is an advantage that cannot be overstated.

"Most of the firms that supplied primary cable to the electric utilities now supply it to the wind farm industry as well," states Granquist. "But it helps that Hendrix has been doing it long enough that we can have shorter, more productive conversations. We no longer have to work through the same issues over and over again. They know how the wind-power industry works in terms of the cable requirements that are unique to an industry whose projects are out in the middle of nowhere and released on a variable schedule. That's pretty handy to have."

In the end, CEG and Hendrix have both gained insight into each other's world. CEG has learned about cable manufacturing and Hendrix has become more knowledgeable about wind power project management. Through this close-knit relationship, both companies have crafted a unique approach to serving the wind power market.

And that's not just blowing hot air.

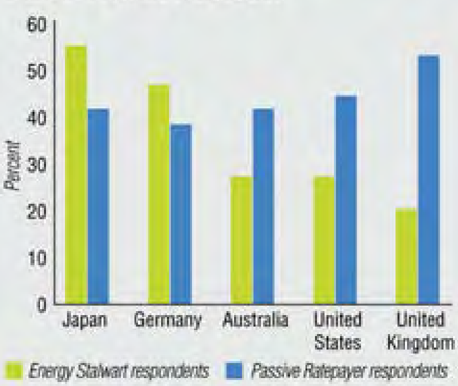
PLUGGING IN THE CONSUMER - PART II: DOES YOUTUBE INFER YOUENERGY?

By Michael Valocchi, Global Energy & Utilities Leader, IBM Global Business Services

Energy Stalwarts are the trailblazers for competitive choice, conservation and technology adoption.

They typically exhibit one or more of the following characteristics: are environmentally conscious; have high reliability needs, for instance because of home electronics or healthcare monitoring devices; or express interest in long-term savings and/or less dependence on their utilities. In every benefit scenario we asked about, between 30 and 50 percent of this group said they were "very likely" to deploy self-generation technology, which is a higher rating than any other segment. Interestingly, Energy Stalwarts actually outnumber Passive Ratepayers in two of the six nations where we surveyed – Japan and Germany (see Figure 6).

FIGURE 6.
Number of Energy Stalwarts as compared to number of Passive Ratepayers.



Source: IBM Institute for Business Value 2007 Utility Consumer Survey.
Note: The Netherlands could not be included in this chart due to insufficient data.

INDUSTRY MODELS

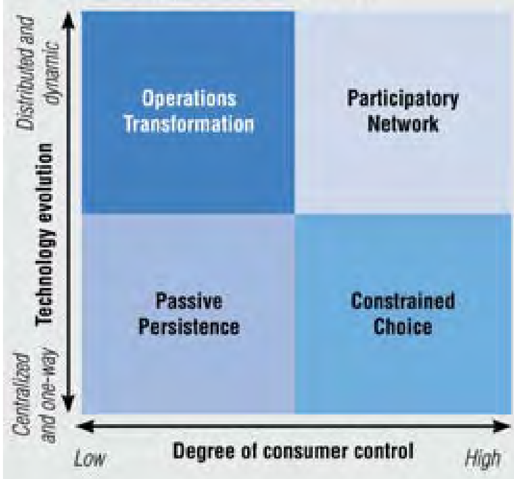
Based on our research, we believe the two factors that will have the most influence over the future of the utility industry are technology evolution and the degree of consumer control.

At the lower end of the technology spectrum, power generation is centralized, and information and energy flow in only one direction. At the upper end, smart metering, enhanced network sensing and communications, and self-generation technologies create a dynamic consumption/generation network where information and energy flow in both directions. In terms of consumer control, one extreme represents a completely "utility-determined" relationship, in which consumers have very little say.

The opposite extreme is a "customer-driven" experience, with consumers controlling major aspects of how they meet their energy needs.

Analyzing the impact of combinations of different levels of progression in these two areas suggests four industry models (see Figure 7). Though each one is described distinctly here, the industry as a whole – at least in the near term – will be an amalgam of all four.

Figure 7.
Four industry models, 2007 to 2017.



Source: IBM Institute for Business Value analysis.

• Passive Persistence – In this part of the industry, traditional utility market structures still dominate, and consumers either accept or prefer the historical supplier-user relationship.

• Operations Transformation – Here, some combination of grid and network technology evolves to enable shared responsibility, but consumers either cannot (or elect not to) exert much control. The balance of benefits from new technology deployment favors the utility.

• Constrained Choice – In this industry model, consumers take decisive steps toward more control, but are limited to certain "levers" (technologies, usage decisions or choices in providers) by regulatory and/or technological constraints.

• Participatory Network – This environment is characterized by a wide variety of grid and network technologies that enable shared responsibility. Consumers' strong interest in specific energy goals creates entirely new markets (virtual and physical) and new product demands, which balances the benefits of new technology deployment more evenly between consumers and utilities.

Despite the varying pace of change across regions, we see the movement toward a Participatory Network as inevitable – technology advancement and consumers' appetites for control only march in one direction. However, the path the industry – both collectively and as individual companies – takes will be determined in large part by how rapidly technological, market and regulatory barriers fall. The evolution along the technology and consumer control axes will occur at varying rates in each market, with various regions operating under different models at any given time. For this reason, a utility with a service territory that spans multiple geographic areas might have to manage more than one model simultaneously – at least until a Participatory Network structure becomes widespread.

NEW INFORMATION FLOWS AND NEW BUSINESS MODEL POSSIBILITIES

As consumers sort themselves into

segments with distinct needs and wants and the industry is pushed toward Participatory Networks, the fundamental nature of the utility industry is changing.

In the past, electricity was primarily generated in a centralized location, transmitted to the grid and eventually distributed to the end user.

Businesses were defined by the part they played in getting electricity to consumers: generation, transmission, distributors, and others.

The entire value chain was structured around power flow (see Figure 8).

But as generation decentralizes and smart meters and intelligent networks enable Real-time data exchange, utilities will be forced to manage increasingly voluminous and complex new information flows in addition to energy flows. Historically, a utility's primary information exchange with consumers was related to the monthly bill. But in a fully implemented Participatory Network, real-time data on consumer usage will be available, enhancing utilities' ability to forecast and balance loads and offer targeted products and services to customers on a more individualized basis. Where distributed generation is in the mix, power from multiple sources will have to be metered, reconciled and billed.

For these reasons, information flow will play a much greater role in shaping the industry value chain (see Figure 9). With the right regulatory framework, this information-rich environment could spawn a range of new products, services and business models.

RECOMMENDED FOCUS AREAS

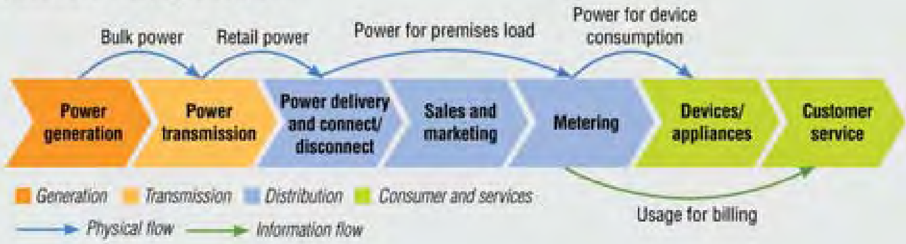
So how can energy companies best prepare for this very different future? We suggest starting with development of long-term business and regulatory strategies for transitioning to a Participatory Network, the key elements of which will be creating a plan for capturing value from new consumer information flows and using customer analytics to gain a deeper understanding of consumers.

TRANSITIONING TO A PARTICIPATORY NETWORK

Based on our research and analysis of the utilities industry, we believe a full-fledged Participatory Network will ultimately emerge.

Elements of such a network are already in place within several major markets. The question is not if a fully

FIGURE 8.
The traditional industry value chain.



Source: IBM Institute for Business Value.

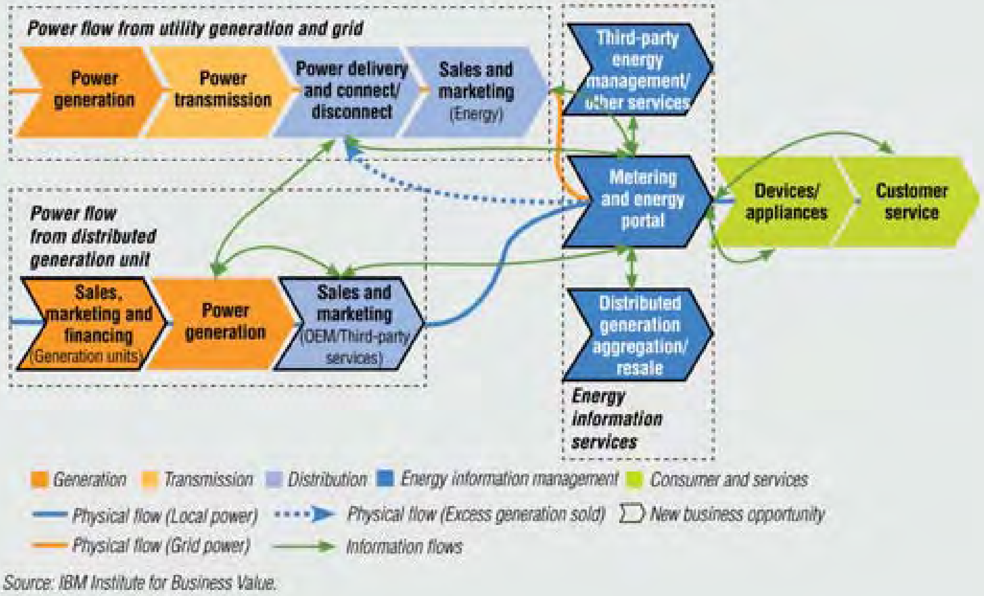
participatory environment will emerge, but when.

Even though some utilities may choose not to provide all of the capabilities inherent in a complete Participatory Network (ceding those roles to rivals or other specialized players) – they will still be part of the network.

Consequently, utilities of all scopes and sizes should be prepared to be swept along into this consumer-driven, technology-enabled environment.

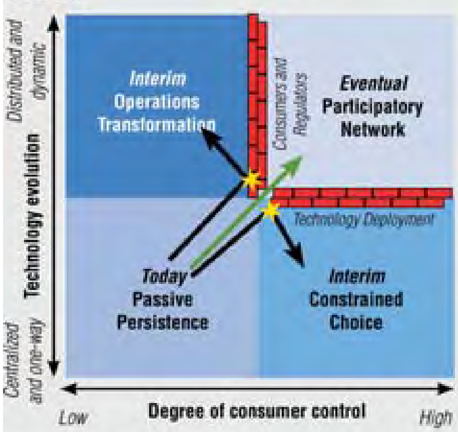
In the short term, various regulatory, economic, market and technological barriers will prevent many utilities from moving directly to a Participatory Network. The particular combination of factors a specific utility faces will instead push it toward one of two transitional paths: through Operations Transformation or through Constrained Choice (see Figure 10). Just like the electrons they deliver, utilities will move along the path of least resistance toward the ultimate destination: Participatory Networks.

FIGURE 9.
Dramatic increases in information flow could result in new business opportunities.



Source: IBM Institute for Business Value.

Figure 10.
Most utilities will be blocked and forced down interim paths before reaching a Participatory Network.



Source: IBM Institute for Business Value.

OPERATIONS TRANSFORMATION

A utility is likely to initially move to Operations Transformation when consumer control is blocked or impeded in some way. This could be as a result of a highly regulated market, insufficient competition in an open market or simply a lack of consumer education about available options. If primary fuel costs and/or carbon pricing are low, the price of fossil-generated power will flatten or drop, making renewables much less competitive and giving consumers less incentive to move from the status quo. Regulators may also be reluctant to provide adequate incentives and rate structures for technologies that encourage consumer involvement if there is a perception that consumer acceptance will be weak or that widespread deployment of technologies that enable greater consumer control might not yet be viable.

Utilities that find themselves in this type of environment can still benefit from moves toward a Participatory Network by leveraging available technologies to make operational improvements. For example, network analytics and automation can help utilities:

- Decrease maintenance costs and improve worker productivity;
- Enhance asset performance and extend asset life;
- Manage load more effectively and decrease long-term capital costs;
- Improve reliability and shrink outage durations, reducing potential penalty costs;
- Improve power quality;
- Reduce transmission and distribution costs by lowering power losses.

Even where consumers cannot yet operate distributed generation, utility deployment of these units can help firms improve peak power availability and power quality and reduce total generation costs (especially if carbon constraints impose high costs and the distributed generation technologies are low- or zero-carbon generators).

This transitional period, while moving through Operations Transformation, is a window of opportunity in which utilities can work to improve efficiencies and lower costs. The ultimate goal is to improve their competitive standing in preparation for increased consumer involvement and the eventual move to a Participatory Network.

CONSTRAINED CHOICE

Utilities may be pushed toward Constrained Choice in the short term if technology deployment is delayed in one or more areas. These holdups could be caused by a variety of financial, technological or regulatory reasons.

For instance, certain technologies could be deployed more slowly than anticipated because of capital constraints or insufficient business cases. The lack of standardization could make the integration of network elements difficult. In addition, the regulatory environment may not be conducive to consumer involvement. For example, tariffs may not have tax breaks or sell-back provisions that promote self-generation.

In this environment, consumers may want more control, but their choices and capabilities are still limited. Although competition from new entrants will intensify, rivals will face the same barri-

Continued on Page 38

Continued from Page 36

ers. This, in some sense, gives incumbent utilities "priority access" to the consumers that will be most receptive to new products and services. While temporarily confined in a Constrained Choice environment, utilities will need to take advantage of this access to strengthen their brands and prevent customer defection in the long run.

Customer analytics become critical in this state. Utilities will need to use whatever data is available to determine which consumers are most valuable and which are most likely to take advantage of participatory opportunities as they emerge.

Utilities will also have to evaluate new competitors and offerings. If the offerings are easily replicable by the utility, a rapid response can keep the utility "relevant" in consumers' minds.

If the offerings cannot be replicated, substitute offerings must be developed – or revenue models must be adjusted to reflect a world in which these customers have moved some or all of their business elsewhere.

After these assessments, a utility may elect to pursue one or more of the following actions:

• Position itself as an energy educator, advising interested consumers on how to navigate complex regulatory or market structures to meet their needs or showing consumers why certain behavior changes benefit them.

• Experiment boldly with new programs, particularly to address the needs of profitable consumers who may be lost to new entrants.

• Take the lead in pushing forward regulation that gets the Participatory Network rolling; where more active consumers are the most profitable ones, this helps gain their trust and support – and subsequently their future business.

By building brand and meeting as many needs as possible under the existing regulatory regime, utilities in Constrained Choice can position themselves as the provider of choice for their most profitable customers as new products and services become feasible.

LEVERAGING NEW INFORMATION FLOWS

As the industry moves toward a Participatory Network, information will grow increasingly more critical. As they transition through different industry models, utilities must consider what information is available and how they can best use it.

IN PASSIVE PERSISTENCE

Utilities operating in this environment lack much of the technology deployment necessary to capture real-time consumer usage data. Thus, they will generally be limited to information available from more traditional analytics. Based on the information that can be gathered from bill analysis and in-place customer information systems, utilities can design programs that appeal to a broad base of consumers. As different programs are piloted, firms can collect customer feedback and track the profile of those interested to determine future direction for both technology deployment and customer programs.

IN OPERATIONS TRANSFORMATION

In this environment, utilities still have limited consumer involvement, but do have technology in place to access real-time energy data. These consumer load profiles can help utilities determine base-load and peaking needs for optimal generation, transmission and distribution capacity planning. This data can also be used to optimize consumer pricing (peak/off-peak) as well as wire-use charges levied on other bulk transmitters.

Utilities can use improved location-specific outage and power quality information to proactively address incipient problems before they become customer satisfaction issues.

Figure 11.
Differing needs will drive different approaches for each consumer segment.

	Passive Ratepayers / Energy Epicures	Frugal Goal Seekers	Energy Stalwarts
Technology leveraged	• Traditional generation • Traditional distribution networks	• Utility-owned renewables • Low-cost (to consumer) intelligent network capabilities*	• Self-generation • Utility-owned renewables • Full-spectrum intelligent network capabilities*
Service packages	• Traditional utility service • Remote notification (Energy Epicures)	• Time-of-use program • Efficiency incentives • Subsidized programs	• Green power packages • Grid power with backup power system • Time-of-use program • Remote notification
Communication	• Targeted bill inserts (best candidates from customer analysis) • Public education/mass media outreach	• Public education/mass media outreach • Association/interest group messaging • Financial incentives/assistance • Product tie-ins • Corporate social responsibility publicity	• Direct marketing • Special interest media (magazines, Web sites) • Association/interest group messaging • Product tie-ins

** Intelligent network capabilities include smart meters as well as network automation and analytics*
Source: IBM Institute for Business Value analysis.

IN CONSTRAINED CHOICE

Under this model, some utility consumers are interested in actively managing energy usage, but the necessary technologies may not yet be deployed. Utilities should consider ways to involve these motivated consumers in early adoption programs once consumer commercialization of the technologies begins.

For example, they could allow consumers to explore distributed generation options facilitated by the utility or its business partners or participate in smart meter pilots. The usage information collected from a limited set of highly active consumers can help firms build business cases for new products and services and technology deployment.

Customer data analysis can help utilities identify and reach consumers who may be more profitable or more loyal if they are allowed to become more actively involved in their own energy management.

IN A PARTICIPATORY NETWORK

When consumer participation is high and sophisticated technologies have been widely deployed, utilities will be able to develop rich and useful customer segmentation and behavior pattern data over time. They will also have real-time usage information from appliances, devices and distributed generation units that can communicate with the network.

Customer analytics will become even more important as the wealth of information and the pressure from competitors and new entrants for the most profitable customers grow. These capabilities will allow utilities to develop valuable insights that lead to new programs and products that appeal to an expanding number of increasingly involved consumers.

UNDERSTANDING CONSUMERS

Each evolving consumer segment has specific needs and wants, which means utilities need different strategies, and most likely different offerings, for each (see Figure 11). For Passive Ratepayers, utilities will need simple, uncomplicated offerings that require little effort on the part of the consumer. For example, a time-of-use pricing plan structured in large blocks of time (like mobile phone plans that offer cheaper rates after 9:00 p.m.) might encourage some of these customers to make slight adjustments in their typical consumption patterns.

Passive Ratepayers usually require little attention from their utilities. However, some utilities may decide it is worthwhile to attempt to move some Passive Ratepayers into another more energy-conscious category (Frugal Goal Seekers or Energy Stalwarts). For instance, if a utility's transmission capacity is constrained or generation levels are approaching ceilings imposed by fixed capacity or emissions penalties, it may be advantageous to encourage a shift. Where this is the case, companies can either use mass-market techniques such as general public awareness campaigns or more precise actions such as targeted bill inserts. For these more targeted techniques, companies can use customer analytics to identify those consumers most likely to change if given sufficient education and incentives.

For Frugal Goal Seekers, utilities will need offerings and programs that require little or no financial investment from the consumer. This might include education on voluntary energy-efficiency actions (the use of high-efficiency light bulbs, programmable thermostats and other conservation techniques) and low-cost information devices. Because many Frugal Goal Seekers are interested in minimizing the environmental impact of their energy usage, utilities have an opportunity to access government subsidies for green energy choices that would be popular with this group.

Time-of-use programs for this segment could have a more complex design, since these consumers are more committed and willing to be actively involved. Offerings that include financial assistance or incentives would appeal to this group (including possible financing of major equipment purchases), as would product tie-ins such as energy savings associated with the purchase of a high-efficiency washing machine. This group may also be more attuned to public education and messages channeled through associations and interest groups. Many in this group are concerned about corporate social responsibility, and positive publicity in this area will be particularly important to retain these consumers in a competitive market.

Energy Epicures typically require very little effort to serve and could be a source of revenue growth as upper-end, digital homes proliferate. Utilities likely will want to stay the course with these happy and profitable consumers – unless transmission, environmental or other constraints are confronted. If a utility has reason to convert Energy Epicures into Energy Stalwarts, special programs will be needed to reach these high-use but conservation- averse consumers. For instance, a utility could partner with manufacturers of high-end consumer electronics to bundle an energy-efficiency package into the equipment purchase, effectively lowering the cost of the equipment.

This group might also be intrigued by "leading edge" convenience features enabled by the intelligent network, such as remote notification and control capabilities. To reach this group with conservation messages, companies will need to utilize specific channels these consumers frequent, such as mobile and Internet channels as well as clubs, events, social networks and media programming associated with gaming or sports. Promotion of distributed generation is feasible for this group, but the benefits would need to be stated in a way that would catch Epicures' attention and appeal to their desire to possess the latest in technology innovation.

Energy Stalwarts are arguably the most demanding of the four segments – but likely the most attractive customers in the long run.

They want options and choices. They're often interested in green power packages, self-generation, real-time pricing programs – and perhaps even access to the spot market to cover a shortfall in their own generating capacity. Their interests and higher disposable income also translate into a high likelihood of emerging as early technology adopters, which can be leveraged to bring costs down over time and make new technologies more economically accessible to a broader base of customers. One of the most valuable services utilities can provide to this segment is information – what options are available, where equipment can be purchased, how to estimate savings and costs and so on. Utilities can also offer this segment nontraditional services, such as financing, installation and maintenance for solar panels, micro-combined heat and power devices and other distributed generation equipment.

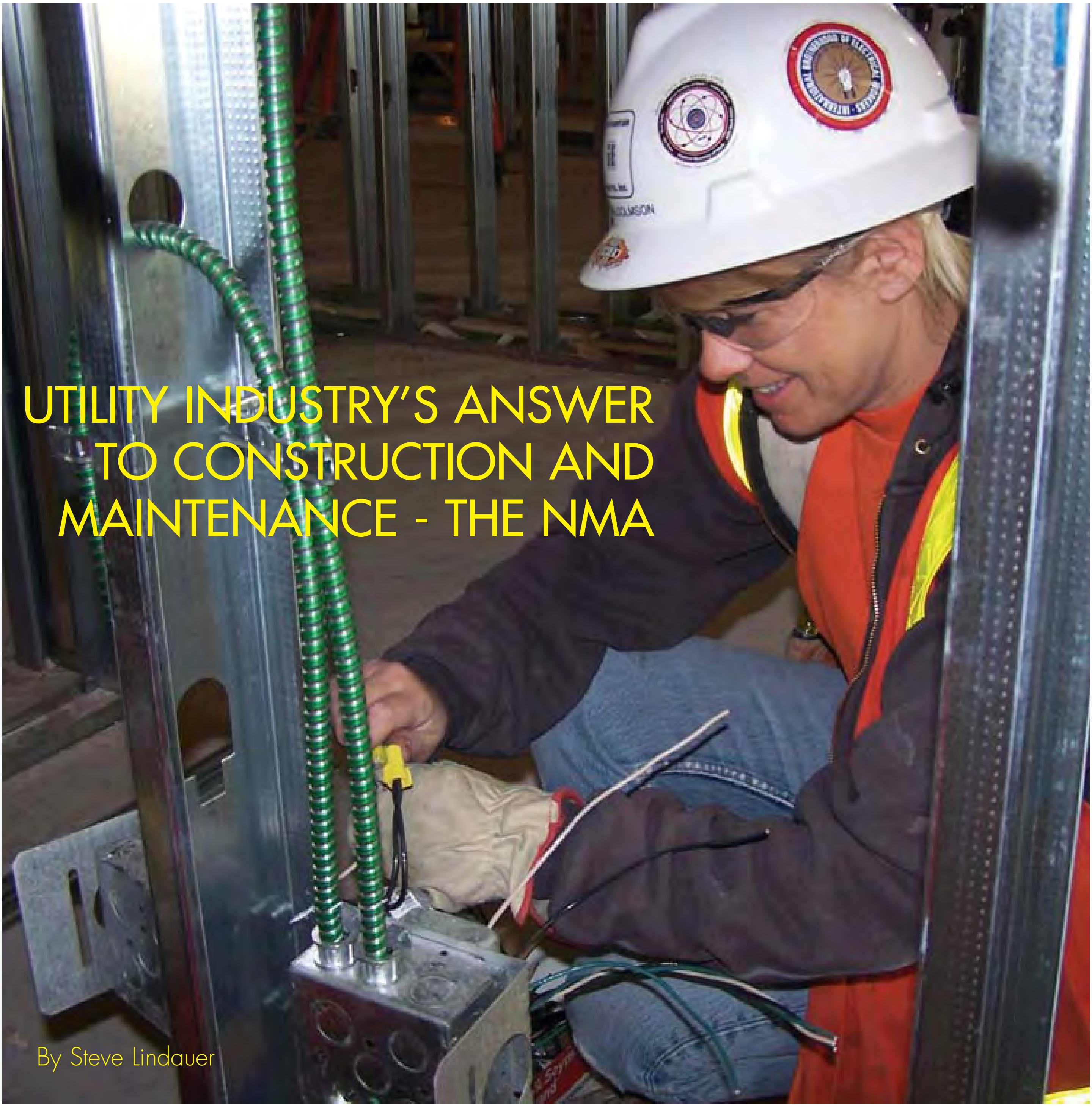
To reach this audience, power companies should consider direct marketing, special interest media and social networking approaches.

But before utilities can begin tailoring their approaches to particular segments, most will need to invest in tools and capabilities that help them collect and analyze consumer data, particularly new information streams.

Using these advanced analytical capabilities, firms can begin to calculate the profitability of particular segments. With these insights, utilities can develop strategies for moving consumers to more profitable profiles, where possible, or investigate ways to lower the cost of serving less profitable segments that are not likely to budge.

The insights from more sophisticated analytics also enable utilities to customize packages and programs based on fact-based analysis of consumer behavior, demographics and expressed interest. As utilities begin to offer a wider variety of programs and packages, it will be critically important to develop expertise in test marketing and running pilot projects.

Fine-tuning such capabilities will help firms more accurately gauge consumer interest levels as well as spot larger trends that are just emerging.



UTILITY INDUSTRY'S ANSWER TO CONSTRUCTION AND MAINTENANCE - THE NMA

By Steve Lindauer

In some ways, the utility industry provides the most taken for granted convenience in our 21st century lives. Flip the switch – the light comes on. Adjust the thermostat – increase your comfort. Click the mouse – send the email. Now, multiply these actions billions of times everyday, and it's still nearly impossible to imagine and appreciate the amount of electricity we require.

About the only time utilities get any attention is when power is down, or when lawmakers hold the industry's feet to the fire over energy policy. But many owners and facility managers who have a front row seat in the daily operation of these huge plants rely on a very important business tool that is critical to their profitability and safety – the use of the National Maintenance Agreement (NMA).

The NMA is a labor-management

system involving one set of rules followed by more than 2,500 union contractors and 14 building trades that work inside these facilities 24 hours a day, seven days a week. And with so many different specialty contractors and skilled crafts people needed to keep a plant on-line and operating at peak efficiency, the NMA allows all stakeholders to focus on the job at hand, not the quagmire that would result from different contracts being drawn up to accommodate different crafts.

Under an NMA, things like shift times, overtime, holidays, and the implementation of world-class safety programs are consistent across the board. Basically, it's one-stop shopping for owners to take advantage of the skill level each union provides. For long-time users of the agreement, it's the only way to fly. "Under my direction at First Energy, we have been using the NMA for 30 years," says Larry Wargo, Consultant for Contract Services, First Energy Corporation. "I'd have to say it's the single most effective decision we at First Energy have made - past, present and into the future."

The future is now for another NMA veteran, American Electric Power (A.E.P.). A.E.P. delivers electricity to more than five million users in eleven different states. The utility is in the midst of a massive program to build new generation facilities as well as update its current plants to make them more energy efficient and environmentally conscious. Much of the work is completed, but there is much more to be accomplished. A.E.P. Chairman and CEO Michael Morris has high praise for the teamwork aspect the NMA provides. "It's a testament to the diligence of our employees and the skills of thousands of contractors who've worked with us. We've successfully managed one of the largest construction programs in the country and completed all the work on time, or ahead of schedule, and on budget."

At the core of the National Maintenance Agreements' success is the tripartite concept where owner, contractor, and labor all sit at the same table and keep the lines of communication open throughout the project. Labor gets to demonstrate its willingness to become a valuable partner in the project, and owners seize the opportunity to have labor see the world through their eyes. The program is administered by The National Maintenance Agreements Policy Committee (NMAPC). The NMAPC provides a staff of industry and labor relations professionals who keep projects on track by facilitating harmony and cooperation between owners, contractors and labor. When an NMA is implemented from day one of any construction project, success and profit result.

A study by Independent Project Analysis, Inc. (I.P.A.), a group independently funded by some of the largest industrial corporations in the world, has determined that union workers are 17 percent more productive than

Continued on Page 49

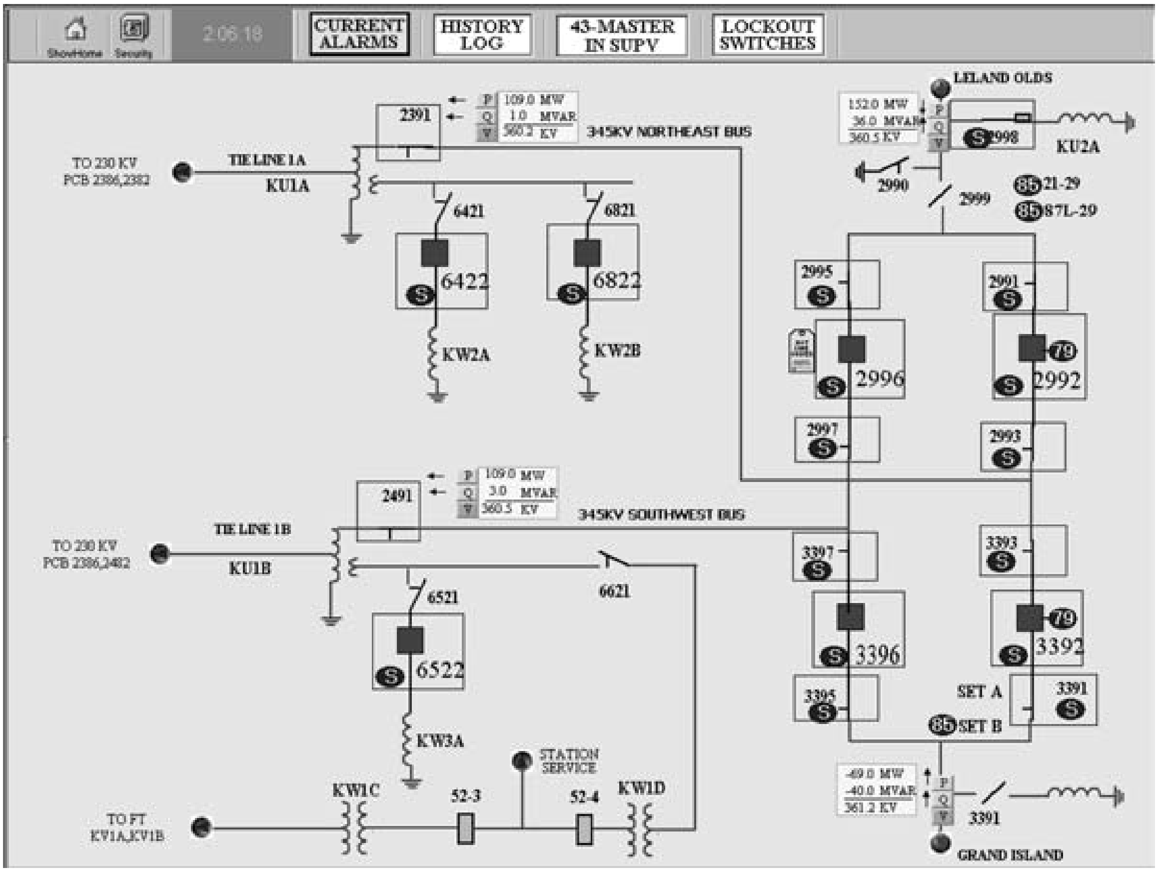


Figure 4 Left Fort Thompson 345 kV yard HMI display. The power flow indication and quantity for the transformers is obtained from adding the individual breaker failure relays. Note the HLO tag on 2996.

Digital Control

Continued from Page 17

directly controlled operation for the MODs adjacent to the circuit breaker via fiber-optic cable.

Eleven MODs and two motor-operated interrupter (MOI) controls were included in the design.

Only DC power was run to the MODs; control is accomplished using the remote I/O devices connected to the fiber-optic cable. Open/close commands are sent via fiber from the individual breaker failure relays to the remote I/O devices.

Reclosing, hot-line orders (HLO), synchronizing, and local/supervisory statuses for the individual power circuit breakers are maintained with latch bits in the individual relays. The latch bits are used in the internal logic of the protective relays to obtain the control functionality.

The HMI control actions are sent to the lower-tier communications processor via the Modbus Plus network. This design allowed for the failure of any one box while still maintaining local control.

SUBSTATION COMPUTER

Hardware Design

Western has used Wonderware as the HMI in their digital designs for several years. Due to the very limited knowledge of this software and computers in general in the workforce and the associated concern over the ability to respond to equipment failure, Western chose an industrial PC. Western purchased redundant PCs with hot-swappable redundant power supplies and hotswappable redundant hard drives. The hard drives use a SCSI RAID 1 controller to mirror the drives. The PCs are rack mounted in the control panel. To provide isolation to transients and to power the PCs, Western installed redundant DC-AC inverters that are normally fed from ac but switch to DC upon

Continued on Page 48

Clarification

To the April article on page 12, “High Resistance Grounding – Avoiding Misapplication of TVSS and UPS Systems”

The sentence on the page should have read:

“During a bolted ground fault on a 600 V system, the neutral voltage rises to 347 V above ground and the two unfaulted phases rise by a factor of √3 to 600 V above ground, as shown in Fig. 2.”

The square root symbol before the “3” had been omitted.

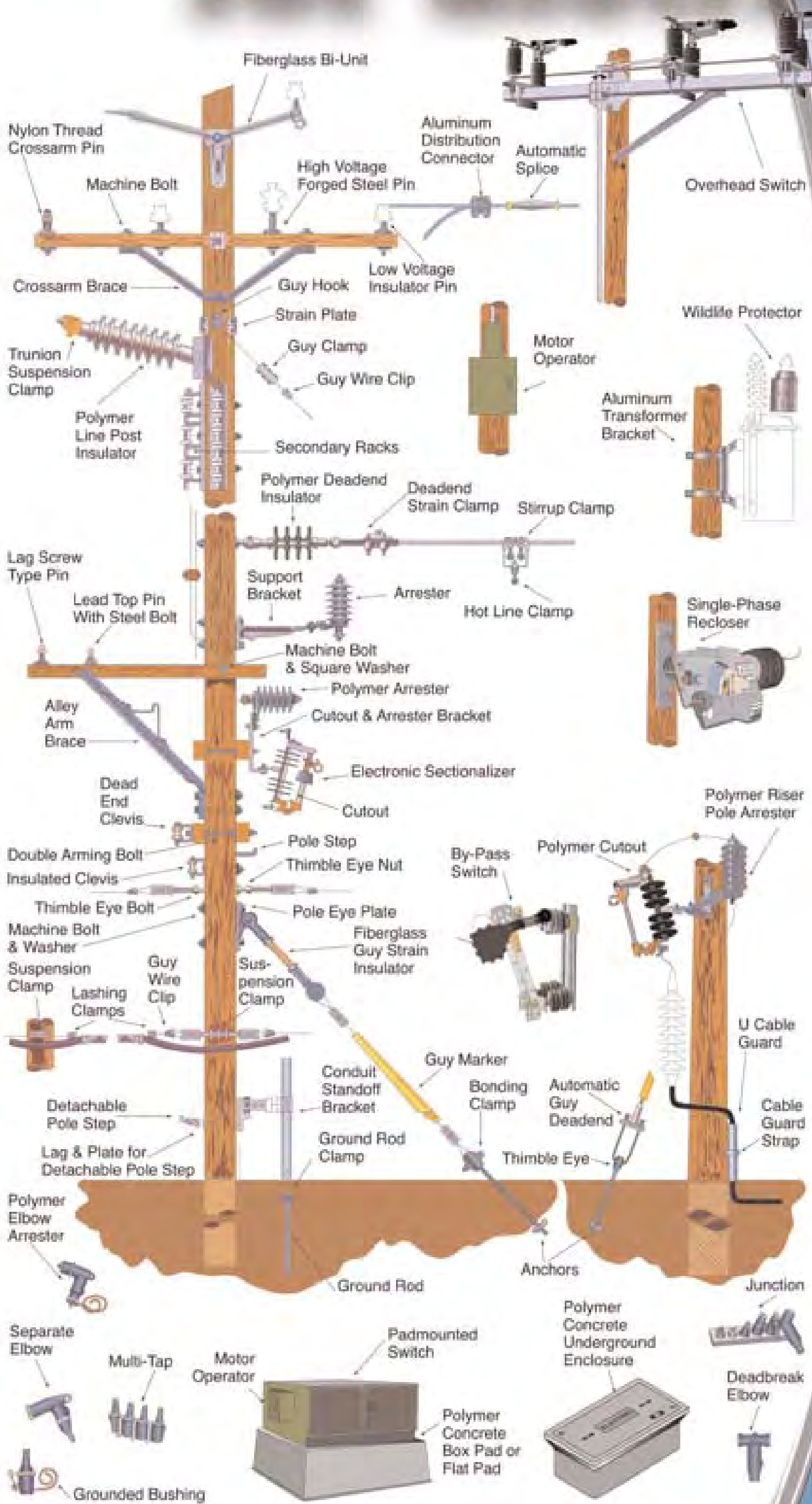
The other sentence on the same page should have read:

“Typically, a 600 V distribution system will be high resistance grounded through a 5 A, 347 V, 69 ohm neutral grounding resistor.

The ohm value was omitted after the “69”.

Electricity Today regrets any confusion these omissions may have caused the reader.

Come here for distribution



We have the products and know-how you need for planning, constructing and maintaining distribution lines. From simple hardware and tools to underground enclosures, sophisticated switching, protection, cable accessories and insulation systems, we help you cut costs, save time and increase efficiency.

With Hubbell, you deal with one vendor capable of supplying 75% of the products you need for distribution poles with product compatibility assured. And, we make doing business together easier than ever with one purchase order, coordinated delivery and overall lower procurement costs.

For distribution, go no further than us. We have the products. The expertise. The support you need. Call us. We're Hubbell.

HUBBELL®

POWER SYSTEMS, INC.

UNITED STATES
210 N. Allen • Centralia, MO 65240
Phone: 573-682-5521 • Fax: 573-682-8714
E-mail: hpsliterature@hps.hubbell.com

MEXICO
Av. Coyoacan No. 1051 • Col. Del Valle
03100 Mexico, D.F. • Phone: 52-55-9151-9999
Fax: 52-55-9151-9988

www.hubbellpowersystems.com

ANDERSON® CHANCE® FARGO® OHIO/BRASS® PCORE® QUAZITE®

CONESVILLE RETROFIT WILL SIGNIFICANTLY REDUCE POLLUTION

AEP's coal-fired generation facility in Conesville, Ohio is undergoing an environmental retrofit that will reduce SO2 and NOx emissions from the plant's largest unit.

American Electric Power's (AEP) 1,745-megawatt coal-fired generation facility in Conesville, Ohio, is in the process of undergoing a $450 million environmental retrofit that will significantly reduce sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions from the plant's largest unit.

"With plans to invest several billion in environmental upgrades by 2010, AEP is one of the top five utilities in the nation in construction spending," said John Blair, construction manager, AEP.

The project involves installation of a jet bubbling reactor (JBR) flue gas desulfurization (FGD) system, as well as a selective catalytic reduction (SCR) system. Associated work on this project includes: balanced draft conversion with addition of induced draft (ID) fans, boiler modifications including water lances and water cannons, a new 800-foot chimney, controls modification with distributive control system, sulfur trioxide mitigation system, economizer replacement with waterside bypass, an FGD substation with underground feeders connected to the cable terminations in the 138-kilovolt switchyard, and a wastewater treatment system.

The FGD process employs a patented JBR in which the flue gas is cleaned by dispersing it directly into the scrubbing solution through gas spargers, eliminating the need for spray devices and recycle pumps for the slurry. The treated flue gas then flows up through the gas risers, into the plenum above the upper deck and out to the mist eliminator and stack.

The process also produces large gypsum crystals (80–90 micron) that can be dewatered easily. During normal operation, the amount of SO2 removed from the flue gas is controlled by varying the JBR pressure-drop or the slurry pH.

However, changing the pressure-drop is easier and quicker to respond to changing conditions, since it is achieved by adjusting the JBR liquid level. Higher liquid levels result in increased SO2 removal because of increased contact time between the incoming flue gas and the scrubbing slurry.

The SCR system for Unit No. 4 utilizes static mixing technology that provides uniform flue gas and ammonia mixing, high NOx removal efficiencies over a wide operating load range, and rapid start-up and commissioning capabilities. This system, which was designed for continuous operation, incorporates technologies and processes developed internally as well as proprietary technologies.

"Equipment was sourced from several countries, including several items that came from India and Europe," said David Yoest, project manager for Kansas City-based engineering firm, Black & Veatch, which designed the FGD system. "Tight space constraints required the team to coordinate the schedule closely so that pieces arrived as they were to be installed," he explained.

The initial engineering for the project, which began in late 2004, included three design phases over a two-year time frame before construction began. Phase I (feasibility study), Phase 2A (preliminary engineering) and Phase 2B (detail design through January 31, 2007) have been completed.

In February, 2007, AEP authorized Black & Veatch to proceed with Phase 3 (complete detail design) and construction management support for the project.

"There is a tremendous amount of daily site coordination between AEP and several contractors on site working side by side within a small construction zone to complete the work in each area safely and on schedule without disrupting AEP's daily operations," said Larry DiCicco, general manager of the Pittsburgh office for Chicago-based contractor Graycor Industrial Constructors Inc.

Graycor Industrial was responsible for substructures and superstructures work for the two-phased project, which began in late 2006 and will be completed in spring 2009.

Phase I, which reached completion at the end of June 2008, entailed substructure work including foundations, underground utilities and roadways, and the stack foundation. The second phase of the project, which began in May 2007 and will be completed in November 2008, involves all superstructures supporting the FGD including nine buildings and pipe racks and complete ductwork fabrication and installation from the existing unit precipitator to the stack through the ID fans and JBR.

PROJECT OVERVIEW

- Number of generating units: four
- Capacity: 1,745 megawatts total
- Unit under construction: Unit No. 4 (820-megawatt supercritical unit)
- Stack height of Unit No. 4: 805 feet
- Average annual coal consumption: 4.3 million tons
- Average annual daily coal use: 12,000 tons

The second phase also includes furnishing and installing two pre-engineered buildings. Final ductwork tie-ins are scheduled for March 2009.

American Electric Power is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S.

AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765 kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas.

AEP's headquarters are in Columbus, Ohio, approximately 70 miles west of Conesville.

THE BENEFITS OF TRANSFORMING TO A LOW-CARBON ECONOMY

By Ritchie Priddy, Director of Business Development, Suez Energy Resources NA

Earlier this year I attended the Carbon Forum in San Francisco and the NYMEX Green Trading Summit in New York. These meetings were not my first foray into the discussion of carbon emissions and, despite conference differences, I left both with the same takeaway – we have reached a tipping point on climate change and its causes.

Each event had its own message – the environmentalists in San Francisco were as zealous as ever about saving the world from calamity, while the bankers in New York were just as passionate about the financial opportunities that climate change promises. The point being that it doesn't matter what you believe. Climate change has been accepted by most, and its impact will affect everyone – including utilities.

While I believe the financial and regulatory segments around the world believe in climate change, I'm not convinced that the public at large will fully commit to the changes necessary to achieve results. Surveys indicate the public believes that climate change is bad, though few can actually define what it is. Most people say they will take action by doing things like changing a few light bulbs. If the problem is as serious as we have been led to believe, nothing short of a major restructuring of the world's economies is in store. And, that calls for a massive change in behavior.

Any social scientist will tell you that behavioral changes are difficult to sustain. Those behind the movement believe they must position climate change as a potentially catastrophic problem, and whatever costs are required must be borne by everyone. But, they forget human nature. When the costs seemingly outweigh the benefits, or the problem is perceived to be solved, human behavior tends to revert to where it was before.

I believe that in order for climate change actions to succeed, we must irrevocably tie climate change to energy efficiency and conservation. Most people still do not make the connection. With high and volatile prices, environmental concerns, the threat of legal exposure, aging infrastructure and among other issues, the perfect storm has emerged. But some would argue the perfect opportunity has emerged as well.

Results of Demand Side Management (DSM) have not always matched the expectation, which is one reason why so many governors and legislatures have forged their own energy policies – often to the detriment of utilities. Increased energy efficiency portfolio standards, mandated energy and emissions reductions, as well as escalated peer pressure have raised the bar. To date, most energy companies have not responded well enough to reduce the regulatory pressure.

Another consideration is the inevitable shift toward mandatory emissions reporting. Right now, reporting is mostly voluntary, but as sustainability practices do become mandatory, so will reporting.

This is often viewed as the Achilles Heel of climate change. Many do not realize the in-depth level of reporting that must take place throughout the entire energy supply chain in order to make a real impact. Measuring the total carbon footprint is imperative, followed by detailed reporting of carbon emissions. In order to enforce sustainability practices, there is a big move for large corporations to report emissions.

In fact, in today's corporate boardrooms, the common practice is to take advantage of this swing to green while leaving out the details of what this movement entails. The result is a snowballing campaign of corporate peer pressure that often forces vaguely worded sustainability statements without specific actions.

So how are traditional utilities being affected by all this?

That's hard to say since each state seems to be writing its own energy policy, but it seems that all state governments are holding transmission, distribution service providers (TDSPs) – even in deregulated areas – responsible for delivering energy reductions. TDSPs should embrace this responsibility and urge deregulated energy companies to join them – after all, every customer wants to lower its energy bills.

In some cases this is happening, but sound energy efficiency and climate change programs should deliver the same results regardless of who delivers them—a more efficient grid. Aside from the environment, the big winner in this scenario is the traditional utility.

The utilities win here because less energy usage translates into lower peak demands, or at least a much slower growth. In turn, this leads to reduced on-peak costs, a decrease in price volatility, fewer transmission and distribution upgrades and, ultimately, better environmental performance. Traditional TDSPs are guaranteed a rate of return for such investments.

But, retail electric providers in deregulated states have a role as well. Right now, they live and die by the amount of energy sold, with no guaranteed return on any energy efficiency investments. As energy providers strive to remain competitive within the marketplace, profit margins continue to shrink, intensifying the pressure to increase sales.

However, by inviting them to the climate change party, utilities can bring the innovation and funding that has traditionally lacked. If given the chance, competitive retailer energy providers can prove to regulators and utilities that they can contribute to increasing energy efficiency, while improving environmental performance of their customers.

YOU SAID IT...

Daryl Shonaman, VP of Engineering & Operations, Saint John Energy, Saint John New Brunswick:

"I have enjoyed reading Electricity Today for many years. Great articles and product information."

Mel Smillie, Project Engineer with Bruce Power, Tiverton, Ontario:

"Great magazine; thanks very much for sending it. Suggestions for future articles: Bruce Power bid to build Bruce C; Bruce County wind turbine projects; Bruce-Milton transmission line project; OPG Niagara tunnel project. Thanks."

Horst Unger, Senior Project Engineer, Electric for Metro Vancouver, Burnaby B.C.:

"Your magazine is an excellent source of information covering the entire spectrum of industrial electrical equipment, application, testing & analysis and good maintenance topics. It has aided me greatly in the performance of my maintenance engineering tasks (along the lines of 'learned something new every day')."

Glenn Cunningham III, Safety Coordinator, Diverse Power Incorporated, LaGrange, Georgia:

"Thanks for providing a great magazine and an easy renewal process! Keep up the good work!"

Reg Gamblin, Engineering Technician, Manitoba Hydro, Winnipeg, Manitoba:

"Electricity Today is a great tool for keeping abreast of the ever-changing utility industry."

Digital Control

Continued from Page 42

loss of AC. The inverters served as a universal power supply, because they switch supply sources without causing any disruption in the PC. A keyboard, video, mouse (KVM) device switches the PCs to a single set of LCD displays, keyboard, and mouse.

HMI Application Design

Western uses a dual display for the HMI. The left screen displays the station one-line with status.

They also use the buttons on the left screen to fill in the variables in the right screen template used for PCB control. The buttons rise when the cursor is placed over them. The 43LS, 79, and 85 statuses are shown directly on the screen. The 43LR, 52a, and 52b drive the color of the breaker status. When the 43LR is in the local position in the circuit breaker, the breaker status box is gray, with an M for “Maintenance” indication independent of the breaker position. The circuit breaker closed indication is red — open is green.

Western’s Power System Clearance procedures detail two primary tagging procedures — one for HLO and one for clearances. Western does not tag equipment controls under clearance with power system clearance tags. The only tag included in the HMI was for hot-line orders. The HLO tag indicates reclosing has been turned off and the circuit breaker close path has been interrupted.

Within the HMI, the HLO tag cannot be turned on when reclosing is in place. The HLO is represented on the one-line screen by a yellow HLO tag and flashing indication on the PCB control screen. If the close function is selected, an HLO WARNING screen is displayed, and closing is prevented.

The PCB control screen has a representation of a physical switch for each function. The switch representation was chosen to make the HMI intuitive. The PCB control screen is the same for all equipment, with only the appropriate functions visible and active. For example, the 85 function is disabled for dedicated transformer breaker, or reclosing for a reactor breaker is disabled. The HMI works by sending the command to the protective relays and then reading the status back via the communications processor to effect changes on the HMI displays. The switch handles rotate and lights change to indicate the appropriate status on the PCB control screen.

Commands to open and close a circuit breaker include a “chicken” or “select-before-operate” switch, which requires confirmation of the selected action. Commands to change the 43, 79, and HLO functions do not require confirmation, as the effect of the command will not immediately impact operation — no circuit breakers will open or close. Placing the 43LS in the supervisory position disables all other controls and is represented with a SUPV label displayed over the control switch handle. The update time on the HMI is about two seconds.

Look for Part II in the October issue of Electricity Today magazine.

The NMA

Continued from Page 41

their open or merit shop counterparts. It's a big number that has touched off more than one debate, but the I.P.A.'s CEO Edward Merrow stands by the result. I.P.A. looks at hundreds of jobs every year and is able to make educated comparisons. "It's the trainin." Merrow says as a primary reason for the difference.

Not only are the craft workers delivered to the job via the NMA more productive, safety is priority one. One of the hallmarks of the NMA is the attention to safety that is stressed as part of the tripartite process. In fact, the NMAPC sponsored Zero Injury Safety Awards are quite possibly the most prestigious in the industrial world. Last year's awards celebrated 9,810,227 injury-free work hours logged under the National Maintenance Agreement. A record 62 winners were honored at the annual gala celebration in Washington, D.C. for ensuring a safe workplace in one of the most dangerous professions in the United States.

Not only do safe jobs increase morale and productivity, they do wonders for insurance rates. Research conducted by the Construction Industry Institute indicates the more owners are involved with safety, the safer their jobs are. And the difference is striking. Owners who were found to be less involved in safety experienced 7.28 incidents for every 200,000 work hours. Those moderately involved had a rate of 2.77 for every 200,000 work hours. Owners who were actively involved in safety had a rate of 1.22 incidents/per 200,000 work hours. The fact that 62 winners were honored last year alone for having zero injuries speaks volumes about the results working under an NMA provides.

Owners who were found to be less involved in safety experienced 7.28 incidents for every 200,000 work hours. Those moderately involved had a rate of 2.77 for every 200,000 work hours. Owners who were actively involved in safety had a rate of 1.22 incidents/per 200,000 work hours. The fact that 62 winners were honored last year alone for have zero injuries speak volumes about the results working under an NMA provides.

Peace of mind, productivity and safety are reasons almost $300 billion in work and 2 billion work hours have been done under the NMA since its inception more than 35 years ago. And while the word "maintenance" is in its title because of the initial focus of the agreement, owners appreciate using the NMA so much that it has expanded into other types of construction jobs such as capital improvements, renovation, and modernization.

The National Maintenance Agreement is used in every major industry in the country including refining, steel, auto manufacturing, chemical and pharmaceuticals. In the end, the National Maintenance Agreement is about doing business to achieve a common goal. And when owner, contractor and labor share a seat at that table, great things happen.

Steve Lindauer is the Impartial Secretary and CEO of the National Maintenance Agreements Policy Committee

ADVERTISERS INDEX