North American Policies and Technologies
ELECTRICITY TODAY
Transmission & Distribution
THE ELECTRICITY FORUM

March 2007
Volume 19, No. 2

High Voltage Lab Sparks Interest on Direct Current Testing

SPRING TRANSFORMER REPORT

KINECTRICS UNVEILS NEW DC TEST LAB
PAGE 33

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
Ann Dunbar
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 19, No. 2 March, 2007

in this issue

editorial board

BRUCE CAMPBELL

JOHN McDONALD

BOB FESMIRE

CHARLIE MACALUSO

DAVID W. MONCUR

SCOTT ROUSE

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.

BOB FESMIRE, ABB

Bob Fesmire is a communications manager in ABB's Power Technologies division. He writes regularly on a range of power industry topics including T&D, IT systems, and policy issues. He is based in Santa Clara, California.

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.

JOHN McDONALD, IEEE President

Mr. McDonald, P.E., is Senior Principal Consultant and Director of Automation, Reliability and Asset Management for KEMA, Inc. He is President-Elect of the IEEE Power Engineering Society (PES), Immediate Past Chair of the IEEE PES Substations Committee, and an IEEE Fellow.

30 New Customers in 2006.

21 New Customers in 2005.

Orion5r 19-Inch Rack Mount

About every other week, Orion becomes another engineer's choice for Substation Automation.

User list available upon request.

Orion5 Transducer Mount

NovaTech®

Visit novatechweb.com/orion.html for complete information detailing the use of Orion in the following applications:

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

Orion Automation Platform

Yeah. It'll do that.

POLITICAL PRESSSURE MOUNTING TO REDUCE EMISSIONS

Don Horne

Cannon to right of them,
Cannon to left of them,
Cannon in front of them
Volley'd and thunder'd;

This famous quote from Alfred Lord Tennyson's "The Charge of the Light Brigade" might become the clarion call for the utility industry on both sides of the border.

In Washington, Democratic leaders in Congress are placing high priority on climate change legislation – legislation that would require decades of investment and innovation to realize reductions in emissions causing greenhouse gases.

In Canada, the ruling minority Conservatives have been presented with a de facto legislative bill requiring them to set a definitive timetable, emission targets and potential penalties for illegal polluters to meet the Kyoto Protocol – a protocol signed by the previous ruling Liberal party and viewed by many in the industry as the greatest threat to maintaining the grid while remaining economically viable.

The potential pitfalls are easy to identify.

North American electric power companies create about one-third of global warming gases. A recent industry study revealed that to reduce emissions below 1990 levels would take about two decades – regardless of how much money was spent.

In fact, the study is viewed by many as being overly optimistic, drawing the conclusion that there is no shortage of money to spend and that every piece of research and new technology applied to reduce emissions is 100 per cent successful.

Ironically, the lifestyles being encouraged among consumers (more household appliances that draw more power and plug-in hybrid electric cars that will dramatically increase electricity demand) only applies more pressure on utilities to keep "dirty" coal generation plants operating.

The Electric Power Research Institute (EPRI) points to a massive nuclear power construction push to meet emission reduction requirements. The study says that 64 gigawatts of nuclear power will be needed by 2030 (roughly two-thirds the current level of nuclear power).

Early indications suggest it would take a decade to build a reactor, and current orders would provide only six or eight within that timeframe (according to the U.S. Energy Department). The EPRI study predicates its findings on 50 reactors being built by 2030.

Where the study really takes a break from reality are the remaining projects leading up to 2030:

that renewables (not including hydroelectricity) which are currently a little more than 2 per cent of total generation would be 6.7 per cent by 2030;

that demand would slow to 1.1 per cent increase per year; whereas the Department of Energy pegs current growth at 1.5 per cent with demand expected to increase annually (based on kilowatt-hours generated);

and finally, that coal plants would ALL be fitted with a technology that would capture carbon dioxide, compress it and pipe it underground for sequestration. The technology is – at this point – only just being demonstrated under laboratory conditions. These refitted coal plants would be expected to generate 14.6 per cent of electricity supplies.

Further, this isn't even entertaining the notion that coal generation plants (currently operating at 33 per cent efficiency) would somehow be able to ratchet those percentages up to almost 50 by 2030.

This is not even taking into account the hundreds of thousands of miles of aging transmission infrastructure that is reaching retirement age, requiring a massive amount of capital to replace towers, poles and substations which are now entering their third, fourth and fifth decade of service.

In Ontario, the pressure to meet Canada's obligations to the Kyoto Protocol at the federal level places that province in the position of where it would force Ontario Power Generation to break the law just to keep the lights on at the legislature in Queen's Park.

Ontario has already postponed the closure date for its coal generation plants due to a lack of immediate new generation and high peak demand during the summer months.

If Ottawa approves such legislation penalizing utilities for using greenhouse gas emitting plants, Ontario might be placed in the position of balancing whether it would be cheaper to pay the fines or purchase power from Quebec, New York or Michigan.

More ridiculous, if that purchased power came from coal generation plants from across the border, it would indeed make Canada's pledge to the Kyoto Protocol both laughable and ludicrous.

don@electricityforum.com

NOT ALL DEMAND IS CREATED EQUAL

By Jeff Tolnar, Chief Technology Officer and,
Heidi Caroline, Vice President, Smart Grid Applications, BPL Global, Ltd.

INTRODUCTION

The imbalance between electricity supply and accelerating growth in electricity demand is quickly reaching critical proportions both domestically and internationally. Issues of energy cost and system reliability are both significant and broad, having the potential to dramatically impact the international economy in a number of ways. The need to find effective and affordable remedies to the problems of the long neglected distribution grid and to restore balance between energy supply and energy demand is indisputable.

This article will focus on establishing the significance of the energy supply/demand imbalance so that the value associated with bringing an effective solution to that imbalance can be fully appreciated within the utility marketplace. For context, it will briefly discuss types of highly-publicized forerunner programs that have attempted to attack this problem. It will then discuss more thoroughly a low risk, high reward direct load management approach called Demand Dispatch that promises a more meaningful long-term remedy. Finally, the paper will discuss (1) how Demand Dispatch technology can be used to reframe the demand/supply imbalance for more effective strategic resolution, (2) the various grid operation areas that will be enhanced by Demand Dispatch technology, and (3) the return on investment potentials.

MARKET CONTEXT

The emerging imbalance between energy supply and demand threatens system stability and reliability, power quality, and the cost of power itself. For years, utility regulation has masked the inefficiencies of our sorely stretched distribution grid, exhausted in light of relentless demand booms. According to the Edison Electric Institute, between August of 1999 and 2000, distribution congestion grew by more than 200%.

A recent article in the Wall Street Journal succinctly framed the problem of energy imbalance with the following statistics:

"A report by the North American Electric Reliability Council warns demand for electricity is increasing three times as fast as resources are being added in the U.S., a trend that could shake electricity-system reliability in the coming decade.

NERC counts 67,000 megawatts of resources in the works in the U.S. versus 141,000 megawatts of expected demand growth by 2015, leaving a shortfall of about 81,000 megawatts, an amount equivalent to 160 large power plants. One megawatt can power 500 to 1,000 homes.

Increasingly, it is left to a deregulated market to determine whether and when new resources get built. Available resources are expected to fall below safe levels in many parts of the U.S. and Canada, such as New England, the Rocky Mountain region and Texas, in the next 2-3 years."

The Wall Street Journal, 10-17-06

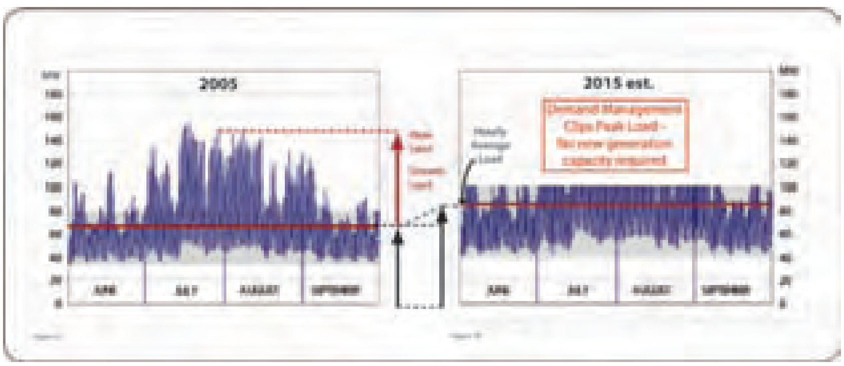
A similar story can be told in many countries around the world. To address this problem in a meaningful timeframe, technologies that delay the need for new generation capacity by trimming peak load are of increasing interest to the power industry. Evidence of this abounds in national publications:

"My biggest fear is that we are running out of generation," said Michael G. Morris, chairman and chief executive of American Electric Power, with 5 million customers in 11 states. "That is an issue that the average person doesn't know a thing about. When we tell corporate America, they say, 'What do you mean you're running out of power?'

North American Electric Reliability Council said in its annual report that in two to three years, the margin between power supply and demand will drop below levels necessary for reliability in Texas, the Northeast and the Midwest.

Demand for electricity is expected to rise 19% by 2015, but generation capacity will grow just by 6%."

Denver Post, 10-22-06



DEMAND MANAGEMENT – A VIABLE ALTERNATIVE

The alternative to attacking the supply/demand imbalance by sinking hundreds of billions of capital dollars into new electric generation capacity is available through a variety of programs known as Demand Management. These programs encourage customers to react to the time-value of electricity and have the potential to rapidly even out demand at a relatively low cost, thereby freeing up existing peak load capacity to meet near term growth in demand, mitigating the reliability and cost issues that arise from the imbalance.

Meaningful success of Demand Management initiatives depends upon the implementation of cost-effective solutions

Continued on Page 10

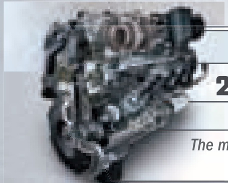
THINK OF IT AS A 137,600 OUNCE PORTERHOUSE.

IT'S 8,600 LBS‡‡ OF GRADE A CAPABILITY. THE ALL-NEW 2008 SUPER DUTY.

BIGGER. TOUGHER. MEANER. THE TRIED AND TESTED SUPER DUTY WELCOMES ITS NEWEST, MOST POWERFUL MEMBER–THE F-450.* AND THIS ONE MEANS BUSINESS.

Pickup cab or living room? You make the call.††

Just pop the hood. With an all-new 6.4L Power Stroke Turbo Diesel V8,† the new Super Duty churns out 600 lb-ft of torque right off the blocks. And with dual sequential turbo-chargers it ensures that you have maximum power throughout the gear.



BEST IN CLASS CAPABILITY	
24,500 LBS	**6,000** LBS
TOWING**	PAYLOAD

The most powerful Ford diesel pickup engine ever –The 6.4L Power Stroke Diesel V8.

All of this gives you the capability to tow a mammoth 24,500 lbs, haul 6,000 lbs of payload and the luxury to tear up the road anytime, anywhere.

While on the subject of luxury, you should take a look inside. Fully redesigned, it's one of the most comfortable and luxurious cabs you'll find in a full-size pickup.

All of this is something you would expect from the newest Super Duty. But cleaner and quieter?‡ That's where it crosses the line. Stepping into a league of its own.

More power.* More capability. More luxury. Once again F-Series redefines the full-size pickup.

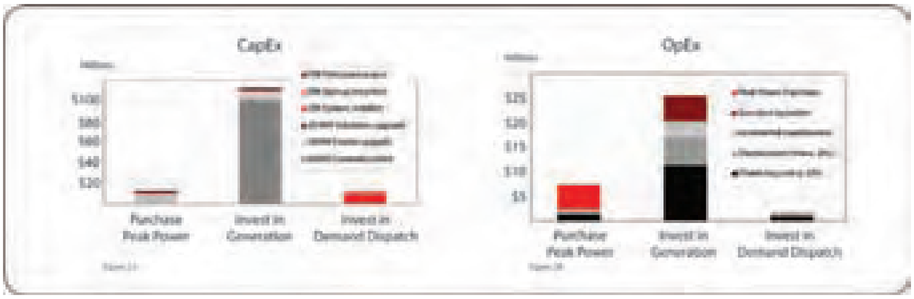
THE 2008 **SUPER DUTY**

BUILT Ford TOUGH

buildfordtough.ca

*Based on the 2008 F-450 best in class payload and towing. Class being full-size pickups over 8500GVWR. † Standard only on the F-450.
** Based on F-450 best in class 5th wheel towing when properly equipped. ‡‡ 4x4 model. †† Optional equipment shown. ‡ Cleaner and quieter than past Super Duty Diesels.

Not Created Equal
Continued from Page 8



that can, within minutes, send signals to thousands of customers, confirm interruptible load shedding activities, or directly control loads or generation at customer sites. Supported by the right technology, Demand Management can be an effective hedge against reliability risks (such as generation shortfalls and distribution congestion) and financial risks (such as wholesale price spikes).

Demand Management technology is a very viable alternative to the traditional method of energy imbalance remediation, which is the construction of new generation facilities.

In addition to being subject to extremely long planning and construction timelines (up to 15 years in many cases), new generation facilities are extremely expensive. New generation facility construction capital expenditures average $1.6 million per Megawatt constructed. In addition, emissions from new generation capacity have a negative environmental impact, increasing carbon dioxide load on our environment. The information below compares average capex and opex costs to a) purchased peak energy from existing generation capacity, b) investment in new generation capacity, and c) investment in technically effective Demand Management.

PURCHASE PEAK ENERGY FROM EXISTING GENERATION CAPACITY

When a utility elects to purchase peak energy to meet growing demand, the increased demand can exceed the design parameters of distribution substations and circuits. In this situation, additional capital is required to upgrade distribution infrastructure to meet growth in demand. As shown on the charts, this level of capital expenditure (capex) required to meet growth in demand is similar to that required to implement a Demand Management system. In all cases, the annual operating expenditures (opex) of a Demand Management system are much lower than purchasing peak energy on the open market.

INVEST IN NEW GENERATION CAPACITY

Investing in new generation capacity is generally the alternative of last resort as the capex and opex costs are significantly higher than other alternatives. Prior to a viable Demand Management alternative, this high cost alternative was the only prudent course of action for most utilities charged with meeting customers' demand requirements.

INVEST IN DEMAND MANAGEMENT

Demand Management, in addition to a relatively low capital cost per customer, has the inherent advantage of no energy cost. This is a significant opex advantage that will increase over time with the relentless upward pressure on energy feedstock.

DEMAND MANAGEMENT MITIGATES RISK

In addition to being an economically attractive alternative to meeting growth in energy demand by shedding peak load, Demand Management reduces significant operational risks including: a) risk of rolling blackouts, b) profit risk due to volatility of energy feedstock, c) risk to assets from overload conditions, d) risks to customers from outages and e) risk to the environment from CO2 emissions.

The risk of rolling blackouts exists even when the utility opts to purchase peak power or invest in generation. With Demand Management, this risk is greatly diminished, because the blackouts are avoided through the more effective distribution of power on the grid.

Profit risk is less of an issue as well, because once the system has been put in place, it very quickly reflects a return on investment and cannot be subject to the seasonal spikes associated with purchasing peak power and investing in generation.

Furthermore, over time, asset protection benefits that accrue from Demand Management programs will reduce risk associated with loss of assets before they have been fully utilized.

Demand limiting functions allow the system operator to select a maximum level of system demand at different layers of the network hierarchy, protecting assets from overload conditions. In conjunction with distributed energy resources, Demand Management can increase system reliability by limiting load placed on the distributed energy resource, extending the time available to repair an outage and limiting customer impact. Because demand response clips peak energy demand, the need for Spinning Reserve capacity is dramatically reduced, eliminating significant waste in power generation and associated CO2 emissions. The following table outlines various risks and their correlation to three approaches to increased demand today:

Risk Type	Purchase Peak Power	Invest in Generation	Invest in Demand Management
Rolling Blackouts	Peak demand beyond capacity to supply can trigger rolling blackouts	Peak demand beyond capacity to supply can trigger rolling blackouts	Peak load is clipped, no major risk of rolling blackouts
Profit Risk	Seasonal peak price spikes can eradicate annual profits	Seasonal fuel price spikes can reduce annual profits	Peak load is clipped, No major financial risk once system is operational
Equipment & Circuit Overload	Peak loads can exceed design limits	Peak loads can exceed design limits	Peak load is clipped, No overload risk
Customer Outages	Probability of customer outages increases at peak load conditions	Probability of customer outages increases at peak load conditions	Peak load is clipped, life of distributed energy resources is extended, reducing risk of customer outage
Clean Energy	Increased CO2 emissions	Increased CO2 emissions	Energy efficient, Peak energy generation avoided

Notes: Generation plant capex $1.6M/MW (Goldman Sachs)
Substation, feeder upgrade capex from PNNL
Demand management system data per BPL Global, industry estimates

"The least appreciated opportunity is energy efficiency and Demand Management. For the 2010 to 2015 timeframe, it's going to be the most cost- effective, least-risky investment we can make," Amory Lovins, Rocky Mountain Institute.

Denver Post, 10-22-06

SUMMARY OF DEMAND MANAGEMENT – OBJECTIVES

In order to properly appreciate any particular method of Demand Management as a potential cure to supply/demand imbalance, it is necessary to understand the five primary

Demand Management objectives. These are:

• System reliability: The Electric Power Research Institute (EPRI) has estimated that power interruptions and inadequate power supply already cause domestic economic losses of more than $100 billion annually. Demand Management programs can enhance reliability of the electric system by providing negotiated reductions in use during peak conditions.

• Cost effectiveness: Demand Management technology is all about cost avoidance and cost reduction. The major costs independent system operators (ISOs) avoid with Demand Management are energy and capacity. Additional savings include reducing line losses within the transmission and distribution system as well as reducing ancillary services such as Spinning Reserves needed to meet short-term load fluctuations and power quality requirements. Demand Management will reduce wholesale market prices and reduce price volatility.

• System efficiency: Demand Management will also boost the efficiency of system capacity by reflecting the variation in power costs through prices.

• Risk management: Demand Management is a risk management tool and will allow utilities to offer customers pricing tools and risk management products that are financially effective and rapidly dispatchable.

• Environmental concerns: Electricity generation is responsible for a significant portion of burdens placed on the environment.

EARLY DEMAND MANAGEMENT APPROACH REQUIRES UPGRADE

Undoubtedly the approach to Demand Management that has received the most attention to date is Advanced Meter Infrastructure (AMI). AMI systems are based on smart meters that provide automatic connect/disconnect feature and automatic meter reading (AMR).

Some systems provide adequate technology to relay limited pricing information to a utility's customers. These early attempts at Demand Management have been constrained in several key areas:

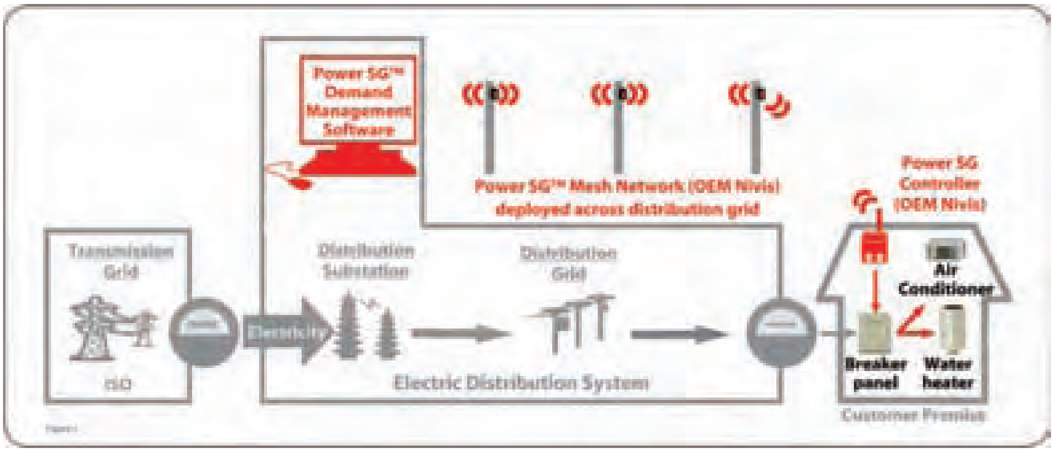
• Typically, AMI solutions use one-way broadcast to relay price signals to customers.

While many AMI solutions have limited two-way communications capability, communication from the premises back to the utility is slowed by the interval requirements of the solution provider's proprietary communications scheme. Therefore, a one-way broadcast (to advise a customer that peak conditions are being reached and some form of real time pricing will be in effect) is the extent of the communication.

• The effectiveness of the AMI solution is reliant on the customer's ability and/or willingness at the time of peak conditions to actually make a change in their consumption.

Customer communications and timely availability about participation during peak load events often limit effectiveness.

• The utility has no way of knowing what non-critical load is available to be shed and has no way of receiving confirmation of how much load was shed. This leaves the utility operator in a "wait and see" mode during peak operational times.



Despite these deficiencies, AMI has received the lion's share of attention as Demand Management technology. Typically the cost justification for a move to AMI has been heavily supported by the operational efficiencies and cost reductions associated with replacing human meter readers and automatic connect/disconnect functionality core to this technology. In a June, 2005 press release, Pacific Gas & Electric announced that AMI would benefit its customers by speeding up power restoration during outages and virtually eliminate the need to estimate customers' bills when meter access is blocked.

To date, the primary justification for AMI is generally based on the benefits of automatic meter reading and automatic connect/disconnect, not Demand Management. Stand alone, AMI falls short of the functionality required by a robust Demand Management system. Better technology exists to facilitate effective Demand Management; and it will be this enhanced technology that the energy industry will have to rely on if Demand Management is to figure into the remediation of the growing supply/demand imbalance.

In combination, AMI plus a system specifically designed for Demand Management can be a powerful combination for a utility to gain information on and control of their distribution network.

DIRECT LOAD CONTROL THROUGH DEMAND DISPATCH

A superior technology exists to facilitate much more effective Demand Management.

This technology is called Demand Dispatch. Demand Dispatch technology implementation interacts directly with specific premise loads to more effectively and granularly manage load across an entire distribution footprint. Using robust two-way communications and power system software to manage a network of premises controllers, Demand Dispatch technology can efficiently manage interruptible load in very granular way – device by device in a customer's premises.

The following graphic illustrates how sensors at the premise can communicate the use of non-essential, interruptible power (for appliances like pool pumps, air conditioners and water heaters). Small amounts of savings from individual premises can add up for impressive grid-wide shedding of non-essential loads.

An enterprise computer system monitors premises conditions for temperature and voltage, houses all information related to usage programs at the premises, sends dispatch instructions to premises controllers, and manages the network via internet connections through multiple radio concentrator units.

These connections can be fiber, wireless, power line or other broadband technology. Concentrators are located across the deployment region in such a way as to provide communications to every premises controller in the system. Residential controllers are small devices placed into every participating end customer premises. These units communicate over the network to the concentrator radios which are then connected back to the central computer.

As compared to 20 years ago, a much larger percentage of load is non-essential. The square footage per family home and person has doubled in the last 30 years. 100% of new homes in the Southern U.S. have air conditioning throughout. Many more homes have pools and pool pumps – all non-essential load devices that can be shed in peak energy usage periods, given a consumer's participation in the program. Demand Dispatch can communicate specifics about the type of load, pinpointing non-essential load and shedding it within the confines of the customer agreement. Utilities cannot be in the position of shedding load inappropriately (they wouldn't want to reduce power on a home dialysis system, for example), but with more intelligent sensors, they can shed load intelligently.

This robust system technology allows for a much more assertive pursuit of supply/demand imbalance remediation. Demand Dispatch gives a powerful meaning to real time. With Demand Dispatch technology, the communications technology provides the utility with information every few minutes, not only providing information about the size of the load, the additional information of type of load (essential or non-essential) will allow for blackout or peak buying risk aversion. This allows for service reliability and a minimal impact on the individual user.

DEMAND DISPATCH KEY POINTS OF DIFFERENTIATION

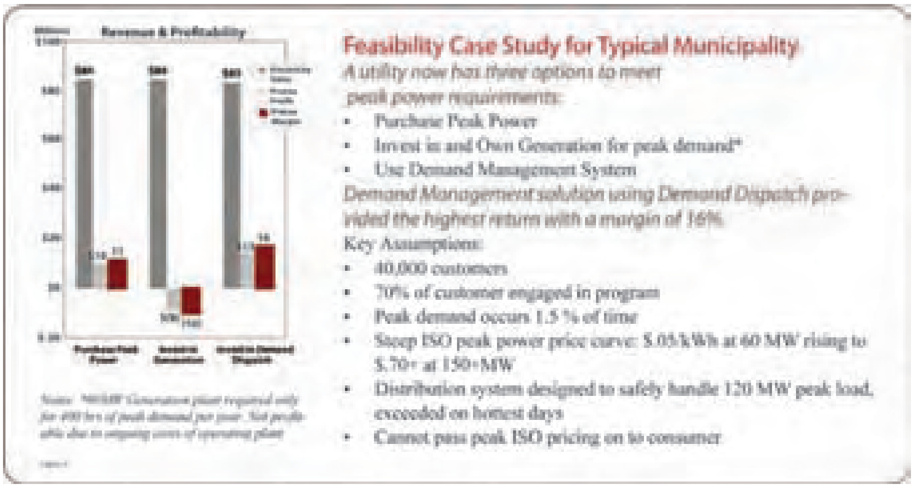
1. Demand Dispatch gives a utility control over when and whether customer load is reduced
   - Utility remains in charge of its revenues
   - Demand Management functionality can be used as an option based on utility's preferences
2. Demand Dispatch provides the operator a real time, accurate view of actual load, true available load and load shedding results as they are implemented and take place
3. Demand Dispatch allows the traditional Demand Management business case to legitimately be expanded to include operational and reliability benefits
4. Demand Dispatch offers a system of greater sophistication, one which is capable of improving regional grid operators and electric utilities' grid management and operations capabilities by enabling access to real time and disaggregated information on demand conditions in specific areas
5. Demand dispatch allows real time confirmation of load shed and direct audit capabilities with wholesale meter data

DEMAND DISPATCH TECHNOLOGY COMPELLING ROI

No company wants to provide less of the product it offers – it wants to meet system demand at all times, and at a margin consistent with overall business objectives. However, if service reliability is compromised, so is the company's relationship with its customers.

Sometimes the investment in new generation and transmission to serve peak demand simply doesn't make good business sense. Therefore, Demand Dispatch must provide a good balance of reduced capital investment PLUS a strong return on investment for the utility.

Of significant importance to the value proposition of Demand Dispatch is the ROI outcome.



Specific feasibility studies indicate that the implementation of Demand Dispatch technology will provide a very attractive return, with a pre-tax margin of 16%.

In one feasibility case study (driven by actual load, price and wholesale grid conditions over an entire peaking season), the following parameters were in place:

- 40,000 customers
- 70% volunteer participants
- Peak demand occurs 1.5% of time
- Steep ISO peak power price curve: $.05/kWh at 60 MW rising to $.70+ at 150+MW
- Distribution system designed to safely handle 120 MW peak load, exceeded on hottest days
- Cannot pass peak ISO pricing on to consumer

The feasibility study results indicated that the most favorable means of addressing the system demand requirements was via Demand Dispatch. When compared to the options of purchasing peak power or investing in generation, the pretax profit margin associated with the Demand Dispatch option was the most promising, at 16%. Investment in generation resulted in a loss, whereas the purchasing of peak power resulted in just an 11% pretax profit margin. It would be expected that peak power profitability would decline even further as demand continues to increase yet supply remains relatively flat.

DEMAND & LOAD MANAGEMENT IS INTEGRAL TO THE OVERALL OPERATIONS OF THE UTILITY

Implemented optimally, Demand Dispatch technology has the potential to properly frame the parameters of the supply/demand imbalance and to enable meaningful corrective strategies.

Meter replacement has gained a good deal of attention over the years, but AMR does little more than reduce a human resource cost for the utility. It is not a solution to matching supply to demand and at best, can only address a small percentage of the demand with low levels of certainty.

By contrast, the technical superiority of Demand Dispatch technology allows it to be deployed more assertively. Implementing Demand Dispatch to produce higher dispatch yields – 10-15% – would significantly reduce the issue of supply imbalance. It would also allow power utilities to pinpoint more granularly and readily those areas where other solutions are required to create balance.

Demand Dispatch deployed optimally will refocus the real issues related to supply and demand. Our focus may shift from building more generation to using existing generation more strategically by managing non-essential loads more aggressively.

Through Demand Dispatch, Smart Grid technology can extend the application of existing generation to adequate levels. The spot problems that remain can then be addressed by other Smart Grid applications like micro-generation, storage products, distributed energy devices, etc. By attacking the problem with technology, properly framing the parameters of the problem and then isolating the seriously in-need areas, the need for overall new generation will be lowered. Demand Dispatch is a highly effective, equalizing technology.

EFFECTIVE DEMAND MANAGEMENT IMPLEMENTATION

Demand management, particularly that using Demand Dispatch, will enable utilities to address short term energy cost issues, and longer term, the projected gap between generation capacity and demand and need to reduce carbon emissions. If not now, in the future, it can:

- Enable Spinning Reserve Replacement and deliver green energy credits in some regions.

Reduction in Spinning Reserve can have a significant and positive operational impact on the utility's bottom line. The implementation of Demand Management paves the way for this reduction. Furthermore, a move toward less reliance on Spinning Reserve will gain the attention of government, regulatory agencies and consumer groups focused on green initiatives.

- Offer Asset Protection capabilities by protecting grid assets from overload conditions and reducing overload strain should extend the "lifespan" of the grid components.
- Provide an essential element for Islanding with distributed generation and energy storage devices. Once a very intelligent Demand Management system is in place, there are enough communications mechanisms on the grid that "islanding" becomes possible. In islanding, the system is separated into smaller islands at a slightly reduced capacity. The islands minimize the load-generation imbalance in each island, isolating them from the source of an outage, thereby allowing for power restoration to customers within an island.

Demand Management that includes Demand Dispatch functionality should be considered by must utilities responsible for distribution and for generation and distribution. It has the potential to reduce operating costs, delay capital investment in new generation capacity and improve grid reliability.

DEMAND DISPATCH SERVES ALL CONSTITUENTS

Implementation of Demand Dispatch technology allows utilities to serve energy consumers better. Utilities cannot profitably serve load spikes by purchasing peak power. Demand Dispatch offers benefits to each utility constituency group:

- consumers would gladly exchange peak supply for lower electricity bills;
- business and industry will welcome a range of pricing plans and increased service reliability;
- utilities will gain improved operational efficiencies and improved asset protection;
- regulatory agencies will look favorably upon increased visibility into grid performance and real-time data that mitigates service disruptions;
- and environmental advocacy groups will welcome the measurable amount of energy savings that can be achieved through existing generation facilities.

BPL Global's Load Management portfolio includes five primary applications driven by Demand Dispatch as a foundation:

- Demand Dispatch – provides the electric utility with the direct load control tools necessary to avoid energy purchasing at peak wholesale prices. The utility manages load shed across the entire distribution footprint based on its overall load clipping requirements and in small increments in order to maintain program comfort thresholds and prices.
- Demand Response Program Offerings – provides electric utility customers with the tools to manage their energy purchases. Customers select from programs offered by the utility that provide a variety of pricing options based on usage patterns, energy cost, and interruptible load. The customer selects a Demand Response program and sets parameters including monthly budget and ambient premise temperature thresholds. DDS automatically adjusts the customer's load based on the customer's profile in response to the current market price of electricity and premise temperature. The utility achieves real time peak load shedding through customer participation.
- Spinning Reserve – utilities can replace high cost Spinning Reserve assets or contracts by shedding peak load instead of supplying it. A true Demand Dispatch program can meet the Spinning Reserve time constraint of 5 minutes availability, whereas a typical Demand Response program can not guarantee a defined amount of load shed nor can it shed dynamically to meet changing needs during peak. Spinning Reserve Replacement continuously monitors total system demand and sheds interruptible load incrementally, in real time to match demand with planned supply. Because the utility cycles through its entire customer base, individual customers do not experience a significant impact.
- Asset Protection – a system demand limiting function allows the system operator to select a maximum level of system demand at different layers of the network hierarchy.

Assets are protected by application of operational thresholds (temperature, voltage) made possible by dynamic management of the premise loads of participating customers.

- Islanding – Demand Dispatch technology is deployed in conjunction with Distributed Energy Resources to extend system reliability and limit load placed on the distributed device in an outage scenario. Using Demand Management to extend Distributed Energy Reserve (DER) usage allows the utility to lower the necessary capacity (and associated costs) per DER to meet its reliability objectives. At $2,300/kW, a reduction of 2 MW can save $4.6 million.

BPL Global has modeled its domestic market potential for Demand Dispatch products at $500 million annually.

Application	Description	Market Drivers	Privately Owned	Government Owned	Investor Owned Distribution Only	Investor Owned Net Generator
Demand Dispatch	Utility controlled load shed	Peak load (and peak load cost) elimination in critical periods. Critical period load management to improve reliability statistics.	✓	✓	✓	
Demand Response	Consumer controlled load shed	Load shaping when distribution system conditions warrant price signal and consumer adjustment. Also deployed in response to regulatory requirements.	✓	✓	✓	
Spinning Reserve Replacement	Emergency load shed in lieu of Spinning Reserve or green energy quota	Substitute for expensive stand-by generation or purchased contract generation (can range from 12-18% of system load). Instantaneous reduction of non-critical load via Demand Dispatch leverages assets in place for supplemental value.	✓	✓	✓	✓
Asset Protection	Load shed to protect overload conditions for specific assets	Using Demand Management to set operational thresholds (instead of overloading circuits, creating extended outages to replace damaged lines, transformers, switched, etc.) and extend asset life reduces overall capitalization costs. Extending asset life to allow for schedule maintenance instead of emergency repair reduces operational costs.	✓	✓	✓	✓
Islanding	Managing demand to extend distributed energy source usage	Using Demand Management to extend Distributed Energy Reserve (DER) usage allows the utility to lower the necessary capacity (and associated costs) per DER to meet their reliability objectives. At $2300/kW, a reduction of 2 MW can save $4.6 million.		✓	✓	✓

OUTLOOK FOR DEMAND MANAGEMENT

Meter replacement has gained a good deal of attention over the years, but AMI is only part of the solution for best matching supply to demand and creating the Smart Grid of the future.

Smarter meters can be part of a much smarter system that can address the reliability problem and have a much longer term impact on the utility – but they must measure more than load, they must measure the type of load and they must be part of the solution to automatically shed that load where possible.

A demand and load management system that included the benefits of Demand Dispatch as described above has the potential to be an integral part of a transformation in the utility industry. We must find a new way to generate, deliver and use power without the waste and inefficiencies of today's system. As the world's appetite for power accelerates, the pressure to solve this problem will increase. The need for significant new generation capacity over the next decade makes this a problem to be solved today.

North America	Sizing
Munis and CoOps in North America	3,000
Average Households Passed	16,000
Assumed adoption of Demand Dispatch, Response or Spinning Reserve replacement within five years	20%
Solution cost (hardware and software) per hhp	$250
Total households equipped over five years	10 Million
Total market size over five years	$2.5 Billion
NA market size p.a. (plus an incremental 10% for recurring license fees and maintenance)	$500 Million

We have the tools in the emerging technologies of a Smart Grid. Utilities and regulators have the opportunity to take on this technology risk and address core issues faced by the industry.

Demand dispatch technology has the potential to:

• Delay the need for new generation capacity

• Reduce the operating cost required to purchase peak energy

• Significantly reduce the energy wasted by Spinning Reserve and conserve energy feedstocks

• Protect our environment by reduce CO2 emissions

• Improve grid reliability by protecting assets from overload conditions and enhancing.

ISLANDING

Finally, Demand Management isn't a stand alone initiative. It can impact many of the utility's operations and all are significant. Investments that can be positively affected along the way include the aforementioned islanding, asset protection and Spinning Reserve replacement.

It is likely that new generation is not yet a necessary step in addressing today's imbalance of supply and demand. The first step is a more intelligent use of the existing resources, and the technology available to do so is here today.

June 17-20, 2007
Williamsburg Lodge and Conference Center
Williamsburg, Virginia

EUFMC

The Electric Utility Fleet Managers Conference (EUFMC) is an annual meeting of fleet managers from investor-owned utility companies. The 2007 event will be held June 17-20 at the Williamsburg Lodge and Conference Center, Williamsburg, Virginia.

Utility companies from across the United States are represented as well as approximately 60 manufacturers and service providers. Representatives from electrical contractors and industry publications also attend. Conference activities include a drive-through utility equipment demonstration and equipment show, as well as a general session program of speakers and presentations on industry issues.

Information on the conference including participation information can be found at **www.eufmc.com**.

ANALYZING DATA IS CRUCIAL TO AVERTING CRITICAL FAILURE OF A TRANSFORMER

By Stan Lindgren, Serveron Corp; Ismael Rivera, Exelon Corp

The Dresden Unit 2 Main Power Transformer was commissioned in November 2003.

During the first three months of operation, the unit experienced some generation of combustible gases. An investigation was performed, including thermography studies of the transformer, and the gassing was correlated to the periods when only half of the coolers were running. No generation of gassing was experienced when all the coolers were running. Further troubleshooting identified that one pump was running backwards.

The Dresden Unit 2 Main Power Transformer continued operating satisfactorily since correcting the miswired pump with no appreciable generation of combustible gases. Figure 1 shows the total generation of individual and total dissolved combustible gases in the transformer for the first year.

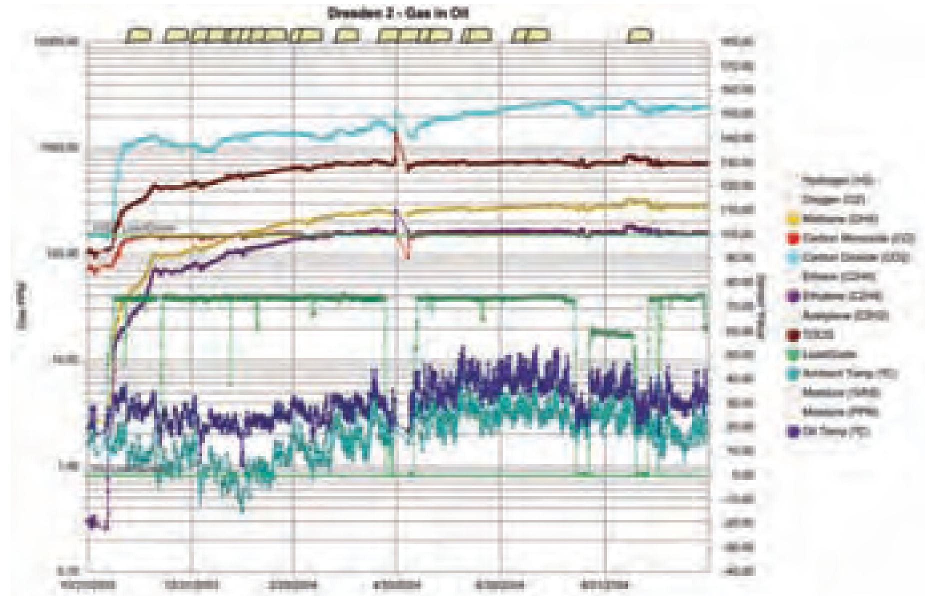


Figure 1: Total dissolved combustible gases (TDCG) and individual "hot-metal" gas ppm (log scale, some gases deleted to simplify chart) for 12 months after Unit 2 was placed in service November 2003. Relative-load, oil temperature (at monitor) & ambient temperature are also shown (linear scale Sensor Value).

SUNDAY AUGUST 28TH 2005

During a daily "walk-around", operations personnel noticed an increase in the Hydran instrument reading from a nominal 55-ppm to about 75-ppm. The System Engineer, while offsite, accessed the Unit 2 Serveron system that continuously monitors and analyzes the transformer gases with results available every four hours and verified that an event on the afternoon of August 28th had resulted in increasing gas generation. Trending of hot metal gasses (methane, ethane, ethylene and extremely low levels of acetylene) took an adverse step increase. Monitoring through the night of August 28th validated a sustained increasing gas-generation trend. Results for subsequent oil samples sent to an independent off-site laboratory also confirmed the increased gas generation trend.

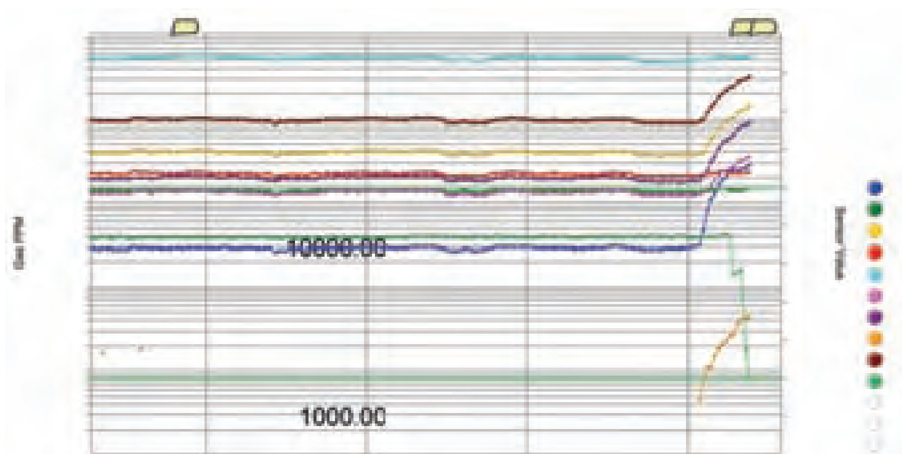


Figure 2: Individual gas ppm (log scale) for 30 days prior to Unit 2 shutdown August 30th 2005. Green trace (relative-load on linear scale) shows load reduction from near 100% followed by total shutdown.

Load was reduced on the transformer with no change in gassing rates and it was taken offline August 30 to perform an internal inspection and repairs if possible. Figure 2 shows the individual and total dissolved combustible gases in the transformer for a 30 day period prior to Unit 2 shutdown. Figure 3 shows individual rate-of-change (ROC) for individual gases and total dissolved combustible gases (TDCG).

INTERNAL INSPECTION

The inspection (following OEM's inspection plan) revealed a severely damaged crimped connection between LV cables connecting an LV winding-exit to

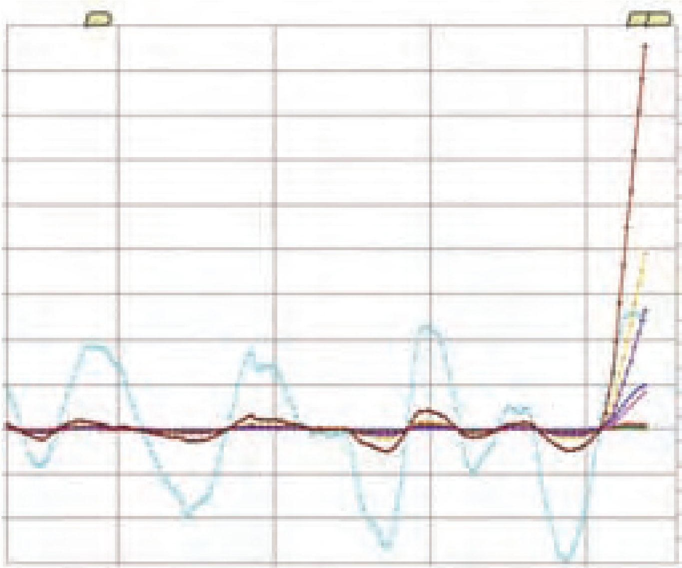


Figure 3: Individual gas ppm/day rate-of-change (ROC-linear scale) for 30 day period prior to Unit 2 shutdown August 30th 2005. [Cycling of CO2 (turquoise) & CO (red) to lesser extent apparently results from absorption & de-sorption of these two gases by cellulose insulation as oil temperature varies.

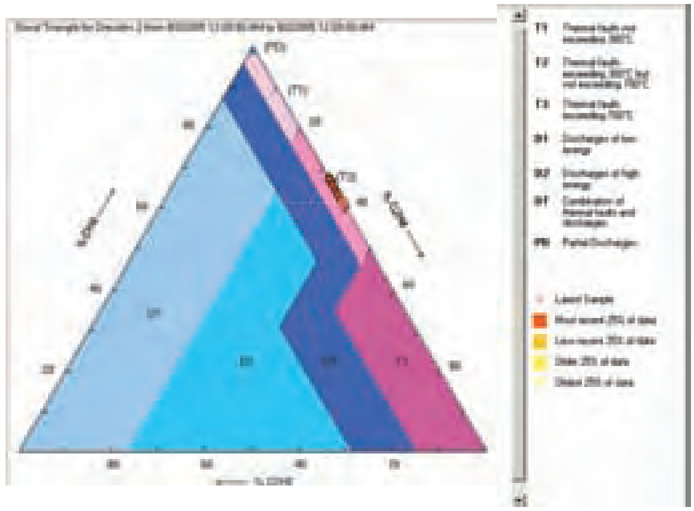


Figure 4: Duval Triangle [1] diagnostic method for the 30 days prior to Unit 2 shutdown indicates T2 Thermal Fault (300–700 C). [Method uses relative % ratios: CH4 ppm/(CH4 + C2H4 + C2H2) ppm; C2H4 ppm/(CH4 + C2H4 + C2H2) ppm & C2H2 ppm/(CH4 + C2H4 + C2H2) ppm to locate a point in the triangle for each set of gas readings. Darkest color is most recent and "x" marks the spot for last set.]

a bushing. The paper wrapping that connection was dark colored. The damaged crimped connection was located on a lead of phase B going from a winding exit to the X2 bushing. A detailed inspection of the damaged connection was performed:

Unwrapping of the connection showed dark colored paper and a severely damaged crimped connection (all the contamination was contained by adequately protecting the area while inspecting).

ANALYSIS

A detailed failure analysis consisting of electrical diagnostic testing and internal inspection performed by the OEM concluded the following:

(1) The gas generation was found to be due to overheated crimped connections caused by a combination of high eddy losses in the crimps, poor oil circulation in the high-current insulated crimped bundled-areas and to a lesser extent by an uneven current distribution.

(2) The most heavily damaged crimped connection had a degenerative condition initiated by a very high working temperature calculated to be >300ºC (consistent with indication per Figure 4) which caused a thermal runaway condition resulting in the sudden gassing increase beginning on August 28th 2005.

(3) The windings have experienced temperature rises consistent with normal operation and hence normal aging.

STRAY FLUX HEATING

The transformer is 1100 MVA three-phase, 17.1 kV nominal LV winding with phase current of 21569Amps. The transformer had been operated at an average value of

Figure 5: Damaged connection was easily separated when manipulated.

950MVA. The cleats and leads arrangement of this transformer has different sections where different bundles of LV cables are located in different relative positions between them. Because of the high resultant current in each of these bundles, a significant stray flux is created in some specific areas of the LV cleats and leads. This flux generates extra losses in the leads particularly in the crimped connections where they exit a bulk area of solid copper.

Different sections of the cleats and leads were studied using a 2D finite element program.

Using that simulation program and some calculation assumptions, the resultant flux in each individual cable and the specific losses per unit length (considering actual working conditions and current distribution) was calculated to determine the effect on the temperature of the cables and crimped connections. The conclusion is that the extra losses caused by the stray flux significantly contributed to increased temperatures of the crimped connections and to a lesser extent in the cables.

POOR COOLING

As a result of the evaluation performed, it was determined that the crimped connections had poor cooling and therefore higher temperatures for two reasons:

(1) The crimped connections were over-insulated: connections did not have a smooth surface due to the crimping. In addition to normal insulation taping, they were taped with semi-conducting carbon paper in direct contact with the conducting surface. This added additional thermal insulation to the crimped area.

(2) Although all the crimped connections in adjacent

Continued on Page 23

CONTINUOUS, CLEAN WATER MEANS FULL STEAM AHEAD FOR ELECTRIC UTILITY

By Ed Sullivan

Filtration of process water demands continuous flow rates, microbic particulate removal and low maintenance – functions best performed by a high-efficiency, automated, centrifugal sand filtration system

Whether for cooling or as a product component, production processes often demand an uninterrupted stream of filtered water. If that water supply is unreliable, contaminated or maintenance-intensive, processes suffer. That invariably translates to diminish product quality, process interruptions and/or exorbitant maintenance costs.

Molded plastics, food and beverage processing, paper manufacturing, metal working, energy, countless process industries depend on filtered fresh water for no-contact cooling or as an integral product component.

"Since no two waters are the same, and all processes differ to varying degrees, those tasked with designing or modifying water treatment systems can only be successful if they balance the requirements of the system that will use the water against the physical and chemical analysis of the water to be treated," advises Phil D'Angelo, Vice President of Technical Development for JoDAN Technologies, Ltd. (Glen Mills, PA). "There are a lot of conditions and requirements to consider: the turbidity of the water, hardness, system pressures, process purity requirements, volume demands, filter backwashes and system maintenance. Certainly, in a process filtration system, minimizing downtime for maintenance is a major consideration."

As opposed to sidestream water filtration used in cooling towers, many process water systems require pretreatment of the water taken from surface or ground water sources. Post filtration process water is often used in combination with other water treatment technologies such as softeners, demineralizers or membranes in a continuous flow mode, feeding process equipment. For many of those applications JoDAN Technologies, a consulting firm that works with industrial and utility clients to resolve water related problems, considers the "centrifugal" sand filtration system a valuable technology. A centrifugal filtration system uses a combination of in-situ fine sand centrifugal separation combined with down-flow sand filtration, which ensures greater filtration efficiency than traditional down-flow sand filters.

Centrifugal filtration systems such as the Vortisand from Sonitec, Inc. are widely used for various process water polishing applications. This fully automated, unusually compact system provides removal of solids to a miniscule 0.45-micron with filtration up to 20 gpm/sq.ft.

Centrifugal filtration sand filter systems are often the best solution to processed water demands.

Sonitec uses a centrifugal sand filter to process water cleaner.

A dramatic example of the advantages of centrifugal water filtration for process applications can be found in a recent JoDAN project at an electric power generation facility located in the northeastern U.S. A relatively small plant that generates 100 MWe from landfill (methane) gas, the plant generates approximately $100,000 worth of electricity per hour during summer peak periods, and therefore could afford little or no downtime.

The power plant uses two 800 psi boilers that run on softened water from large pack bed softeners, which require very clean influent water. Previously the plant had used a large clarifier, to which ferric chloride, sodium hypochlorite and caustic were added to flocculate the suspended materials, control biologicals, and add some alkalinity for boiler water chemistry control. The clarified water then passed through existing pack bed softeners at about 250 gallons per minute (gpm).

"The system was not only supplying water for producing electricity, it was also supplying process steam to a local steel mill," D'Angelo explains. "The steel mill dropped its requirement for steam, so the flow rates dropped from 250 gpm to approximately 50 gpm total. Consequently, the system they had in place was hydraulically too large for the flow requirements."

For an optimal solution, JoDAN put together a filtration and softener package that would utilize the utility's existing pack bed softeners in an intermittent process mode. However, instead of using the clarifiers in front of the softeners, a Vortisand sand filter was proposed.

"We proposed a 150 gpm centrigugal sand filter composed of three vessels, used in processing mode," says D'Angelo. "Although the vessels only needed to be 30 inches in diameter, because of our experience with water treatment equipment, we decided to be on the conservative side and made them 36 inches in diameter. This approach increased the available filtration surface area which optimized the linear velocity (gpm/ft2) and maximized particle loading to a differential pressure end point, which is clearly the correct approach for any filter design."

Now, based on the Softwater Storage Tank level (SWST), river water comes into the plant where it is pre-treated with chemicals before going into the Vortisand filtration system. The filtered water then flows into a 72,000-gallon filtered water storage reservoir. Before entering the boiler, the water passes through a 1-micron absolute pleated filter as well as KDF redox media to remove chlorine, and then into the packed bed water softeners and, finally, into the SWST at 150 gpm. When the SWST is full, the system shuts down until the SWST levels are 2/3 full and the process starts over again.

"When the Vortisand system reaches about a 9 to 10-psi differential, each of the three Vortisand vessels automatically backwashes in sequence," says D'Angelo. "One of the benefits of this filtration technology is that even while a given filter vessel is backwashing, two filter vessels are on-line. Because they are sized at 36-inch diameter, they can easily handle the 150 GPM demand. As a result, the power plant has no downtime, which is of vital importance in any process application."

D'Angelo adds that the filter vessels are backwashed using chlorinated soft water, which controls biologicals. "When you backwash a sand filter, you backwash from the bottom up," he says "It is advantageous to add chlorine or bromine upflow through the filter sand bed in order to avoid any buildup of biological materials. By doing it this way, we're keeping that sand clean all of the time and reducing maintenance requirements and costs."

The new utility plant water treatment system has been running consistently since May 2006. "It has performed extremely well since startup," D'Angelo says.

With its microbial filtering capabilities and high flow rates, the Vortisand filter system is used in a myriad of process applications. Mike Assimus, National Sales Manager at MSC Liquid Filtration Technologies (Enfield, CT), says the system is used to clean water that is used by a major paper manufacturer in the process of making paper wipes used in industrial and medical applications.

"The plant is using well water that is fairly turbid," says Assimus. "They are using 12 Vortisand vessels in an variable-flow system that can handle 600-1,000 gpm, depending on the process requirements."

Filtering the water at a .45-2 micron nominal level is vital because the water flows through high-pressure pumps that impel it to the paper machine, where it is used to form the product. "The water has to be clean to protect the pump and spray nozzles at the water application point, and also must be pure to create a product that is suitable for medical applications," Assimus says. "The spray nozzles have very fine orifices, and if there are any contaminants in them, then the spray will be uneven. Also, impure water under high pressure could cause erosion of the nozzle, also excessive wear and tear on the pumps."

Assimus notes that any downtime due to water system interruptions would be highly problematic because the paper plant has to run fulltime to barely keep up with orders. "They have noticed a decrease in the wear on these nozzles since the Vortisand system was installed," he says. "Not only is that a maintenance time-saver, but a significant money saver as well."

Other design features of the vortexing sand filter system save on process uptime and maintenance costs as well. Alain Blais, Sonitec president, says some major breweries are using the technology for pre-filtration in front of reverse osmosis equipment in the making of beer.

"This removes any particles from the water and ensures a great taste," he says. "But the Vortisand design also reduces the backwashing frequency of the other filtration technologies (e.g. carbon) also used in the process, and reduces the amount of water used. And, very important, there is less maintenance and more process uptime."

Blais adds that a Kansas City soft drink bottler uses the Vortisand filtration system because it is much more compact than the multimedia filtration system that was used previously. "Because this centrifugal technology operates much more efficiently, including a much higher velocity, it takes perhaps 70% less space," he says. "A conventional filter operates at 4-5 gpm/sq. ft. of surface area, while the Vortisand operates at 15-17 gpm/sq. ft. Plus, it uses 70% less water for backwashing than the conventional multimedia filter system."

Sonitec Inc. manufactures innovative products and technologies aimed at improving the quality of the water used in cooling and heating processes in order to improve energy efficiency and environmental performance. In addition to Vortisand, Sonitec water purification and pollution prevention products include Membrane Separation technology.

Ed Sullivan is a technology writer based in Hermosa Beach, California

DEALING WITH PROBLEMS IN OUTPUT RELAYS USED IN MICROPROCESSOR-BASED PROTECTION DEVICES – PART II

By Gurevich Vladimir, Ph.D., Professor, Israel Electric Corp., Central Electric Laboratory

There are in the market completely assembled modules (solid-state relays on basis of IGBT technology) ready to use at 250 VDC.

These modules are larger (58.4 x 45.7 x 22.9 mm) compared to a single IGBT with a driver, but can be used in MPDs of any design as they don't require a printed circuit board or any addition elements for installation (see fig. 9).

Both modules have a high current and overvoltage capability (75A, 1500 V – for 1, and 25A, 1200 V – for 2), that makes them suitable for usage in an MPD.

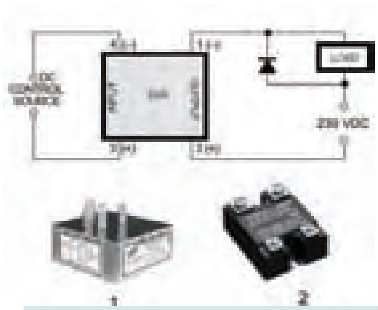


Fig. 9. Solid-state modules for switching of inductive load at 250 VDC
1 – APSW-DC75 type (Applied Power Systems);
2 – SSC1000-25 type (Crydom).

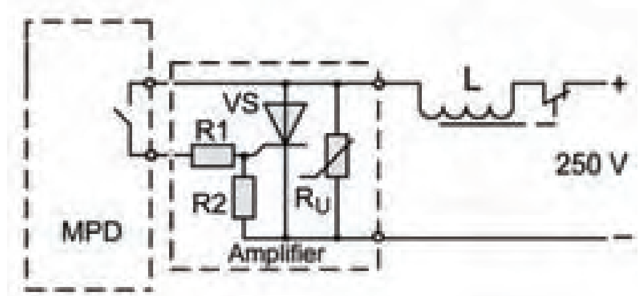


Fig. 10. Simple switching amplifier on single thyristor for trip coil energizing.

IMPROVEMENT OF MDP BY THE OPERATIONAL STAFF OF POWER SYSTEM

One simple solution for the problem of MPD output contacts, including switching-on the CB trip coil, would be to use an external power amplifier of an elementary type and insert it between the output contact of the MPD and the trip coil (fig. 10).

When the single output MPD contact switches on a group

Continued on Page 24

IGBT		IXSK35N120AU1	APT35GN120B	FGA25N120ANTD
Collector-emitter voltage, V	V_{CES}	1200	1200	1200
Collector current, A - continuous - peak	I_C	35 140	94 105	25 90
Collector-emitter saturation voltage, V	$V_{CE(SAT)}$	4 - 8	2.5 – 4.7	3. 5 – 7.5
Total power dissipation, W	P_{tot}	300	379	312
Case type	-	TO-264A	TO-247	TO-3P
Max. operating junction temperature, °C	T_J	150	150	150

Table 4. Parameters of some modern IGBT transistors, suitable for using as output elements of MPD.

Transformer

Continued from Page 19

cables in theory had oil gaps between them, excessive size of the cables in the crimped area plus over-insulation severely reduced the oil gap between the conductors resulting in poor oil circulation and poor cooling.

Reduced cooling due to poor oil circulation was a significant contributor to higher temperatures in certain areas of the cleats and leads, especially in the crimped connections.

UNEVEN CURRENT DISTRIBUTION

Some uneven current distribution was expected in the LV leads based on the design of the windings. Theoretical calculations were confirmed with actual tests indicating current distribution contributed to over-heating spots in some cables and crimped connections.

CRIMP TEMPERATURE

As detailed above, there were two main contributors to the overheating of the crimps.

One is the temperature rise due to eddy losses produced in the crimps by leakage flux from high current in adjacent leads. Considering the actual working conditions that the transformer had during operation, the calculated temperature rise over oil in the worst case was 127ºC. The second main contributor was the reduced cooling caused by poor oil circulation through the eight-cable bundle at some crimps location. Considering that effect and all the others, the calculated temperature rise over oil was 250ºC in the worst case resulting in an absolute temperature higher than 300ºC.

MONITORING CO IN OIL

CO is listed as the key gas for overheated cellulose in IEEE Gas Guide C57.104-1991 and naturally there is a widespread perception that CO ppm is a way to sense insulation thermal problems. It is certainly true overheated cellulose produces CO however C57.104-1991 also implies <350 ppm CO is normal (for new transformers). As shown by the Dresden Unit 2 case involving localized paper damage (in 23124 gal of oil), CO was 200 ppm after 21 months operation at nearly full load and increased only 30 ppm during the 51-hour severe-gassing period, starting August 28, 2005, whereas TDCG (including CO) increased by 2000 ppm. Similarly, an Eskom case (S. Africa)

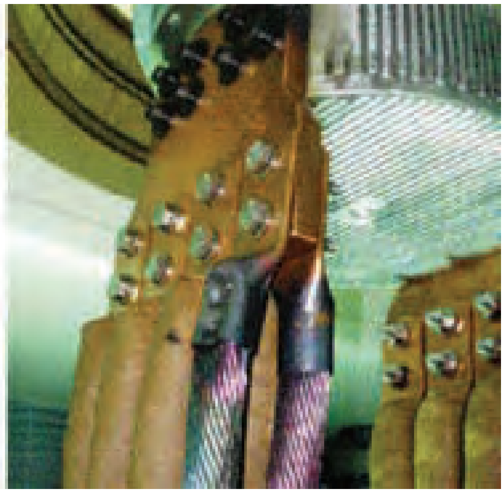


Figure 6: Crimped terminals and cables connected to the bushing's intermediate copper plate.

involving a rather large area of charred paper insulation (due to severely overheated brazed connection in LV winding lead) in a 700 MVA 400 kV GSU transformer (85000 liters of oil) showed CO <200 ppm. In a third case, complete failure of a 230 MVA GSU transformer occurred 2 weeks after a quick rise in CO from 12 to 100 ppm. Simple logic says the total volume of oil involved tends to make a difference in CO ppm generated by a specific thermal problem. But, there appears to be more to it than that.

DYNAMIC BEHAVIOR OF CO & CO2

Normal cellulose insulation aging produces CO2. The more paper there is (i.e. shell-form transformers) & the hotter it operates (i.e. GSU units) the higher the CO2 ppm that tends to accumulate

Continued on Page 46

Output Relays
Continued from Page 22

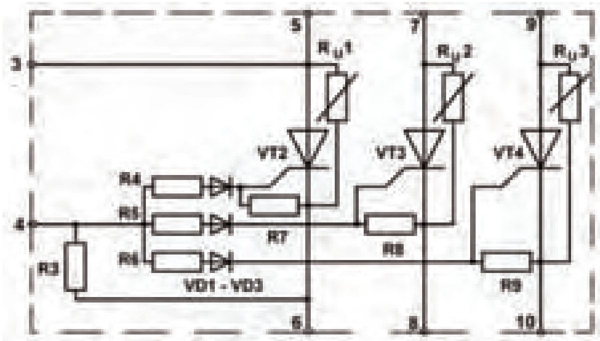


Fig. 11a. Power demultiplexer on thyristors for switch-on the group of trip coil.

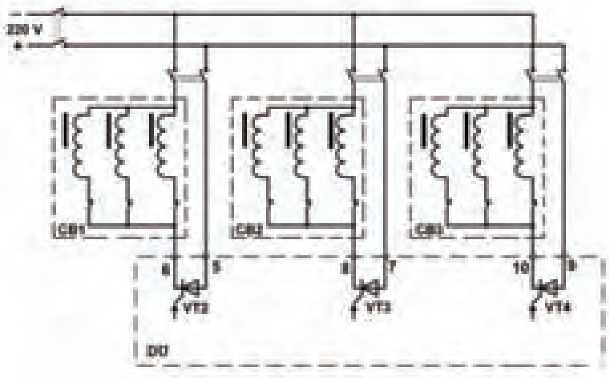


Fig. 11b. Circuit diagram for external connection of power demultiplexer (DU). CB1, CB2, CB3 – three phase circuit breakers.

of trip coils belonging to different circuit breakers, it is possible to use a power de-multiplexer on thyristors (fig. 11) connected to the output of the above mentioned amplifier.

For contacts of auxiliary relays (which require not only switching-on, but also switching-off the inductive load) arc-protective modules of the passive type connected in parallel to

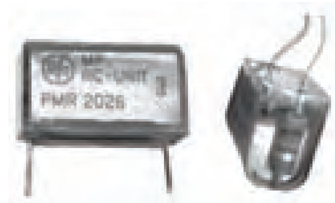


Fig. 12. Passive arc-protective module contains series connected R and C elements (produced by RIFA).

contacts of the relay can be used, for example, a self-made or industrial type RC-circuit (fig.12) manufactured by many companies.

More effective protection of relay contacts against an electric arc is provided by protective modules of the active type, containing semiconductor elements such as transistors (fig. 13).

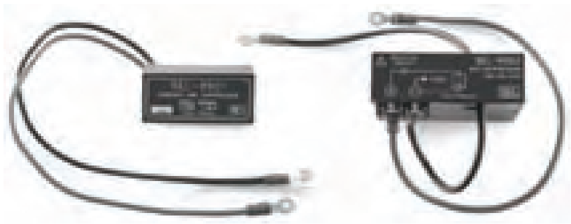


Fig. 13. Smart (active type) arc-protective modules SEL-9501 and SEL-9502 types (produced by SEL).

Naturally, modules of this type are much more complex and expensive than modules of the passive type. Even a more simplified version of such a module (USA Pat. 5703743) contains two transistors (IGBT and FET types), one triac, three diodes, and three Zeners.

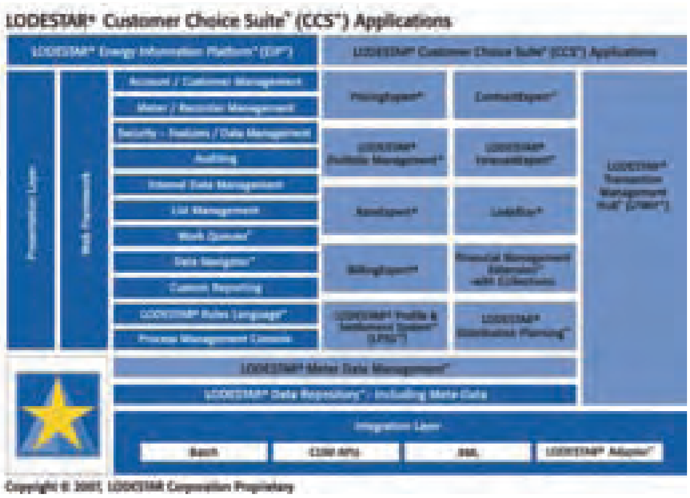
A more sophisticated updating (USA Pat. 6956725) consists of the current transformer, a rectifier bridge, and some capacitors and resistors in addition to the above-listed elements.

Such modules are sold in the open market by Schweitzer Engineering Laboratories and can be successfully used by any MPD operator. The choice of type of protective module depends on the concrete parameters of the switching load. At "light" loads, with the time constant not exceeding 7-10 ms, elementary RC-modules can be used, and for heavy loads with R/L = 30 – 50 ms, active type modules are more suitable.

MANAGING CUSTOMER BEHAVIOR BY COMBINING MDM, BILLING

By Joven Luspo, LODESTAR

Energy supply has been a fundamental challenge of energy providers in recent years. Compounded with the rising cost of fuel, heightened environmental concerns, and an ever increasing global population, managing the balance between our energy supply and our energy demand has become increasingly complex. In an attempt to counter some of the current industry challenges, some markets have resorted to creative means in order to curb our energy appetite.



According to a recent report by Energy Insights, an IDC company, the US Energy Policy Act of 2005 contains multiple provisions dealing with time-based rates, smart metering and demand response. It requires that utilities and retail energy providers offer and provide all customers, upon customer request, with time-based rates within 18 months of enactment. Additionally, utilities and energy retailers must provide a time-based meter to any customer requesting such a rate. The section also requires State public utility commissions to conduct an investigation into time-based metering and communications and issue a decision on whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers.

This, coupled with other provisions that direct the FERC and the Department of Energy (DOE) to conduct studies related to demand response, will most likely result in a number of States adopting mandatory requirements for smart metering. Energy Insights expects these provisions to significantly accelerate the deployment of smart metering systems which include solid-state meters, two-way communications networks, and meter data management applications.

Further complicating the issue is the amount of energy we consume these days. At the same time that generation plant construction dwindled due to emission concerns, our energy consumption requirements increased. As a society, we consume much more than our parents did. We have larger homes, bigger televisions, and more appliances, for example, to make our lives easier. The growth in population multiplies the already increased energy consumption. What's more, many of the same people demanding legislation of energy production, own many of the same "necessities" as everyone else.

One way to balance the energy scale is by enticing consumers to get smarter and more responsible about using power through managing their own consumption. There are initiatives in the marketplace that suggest – or even mandate – to measure and price consumer's usage at an hourly or even sub-hourly level. Different prices throughout the day mean that not only do we pay for the energy that we used, but we also pay for when we used that energy. The goal is to alter consumer's energy usage behavior by shifting their high-energy activities to periods when demand is lower. This, hopefully, also promotes a more conservative consumer. When consumers understand how they use energy and when it is more cost effective to do so, they will ideally use their energy when financially motivated. If enough of us change our behavior, lower efficiency and higher cost generation plants will not have to come on-line as often in order to satisfy the demand.

The optimal way utilities will be able to work within these market trends or mandates is a system that integrates MDM (Meter Data Management) with billing. Such a system can quickly apply hourly or sub-hourly prices to usage and accurately calculate bills. (A classic billing solution is too simplistic to be able to manage the hourly data with different price points.) When prices begin to rise during the day, an integrated system can apply these prices to the consumer's forecasted usage and signal consumers of a possible impending excessive energy bill. Such a system can also be used to detect possible revenue protection violations due to energy theft. Complex filters may be installed to identify and alert users when these revenue violations are suspicious or even absolute. It can also analyze consumption patterns and warn users of possible revenue violations. Revenue protection functionality protects the company from revenue violations or theft by allowing utilities to analyze consumption patterns and flag those who are outside of defined tolerances.

Currently, many industrial customers and large commercial customers use advanced interval meters to support real-time optimization of energy usage and complex billing contracts related to demand response. Also, interval metering samples of all customer types have been used for 25 years to develop fair and equitable energy prices based on actual cost-to-serve each customer type. However in North America, most residential and commercial meters do not measure usage on an hourly basis, although discussions about smart metering are underway in California and Illinois. Once smart meters are installed, and much more data is being measured, the next step will be pricing the energy on an hourly basis. Although an exciting and promising solution to the energy supply concerns, the influx of data and complexity of pricing and billing present a challenge to utilities that is daunting.

And let us not forget about the Sarbanes Oxley Act and its requirements as it relates to data management. It requires accountability in changes to meter data. More specifically, software housing meter data needs to include auditing features to document the who/what/when of all changes. Utilities should include this functionality as part of their requirements.

And foremost, with the constant change in market rules, the system must be flexible enough to adapt to these changes without upsetting the balance already in place. Software with hard coded rules will prove to be inflexible and not as cost effective as a flexible solution that is easily adapted to the changing and future market rules. Utilities need the flexibility to add reports and processes at any time. Likewise, a system that is not scalable or is incapable of keeping up with the pace of the rising amount of data, will also prove to be a burden. With a scalable and flexible system, utilities will avoid costly reinvestments.

> Let us not forget about the Sarbanes Oxley Act and its requirements as it relates to data management. It requires accountability in changes to meter data.

The technology should not limit the number of interval meters, customers or complexity of validations. The system should easily integrate with other systems, leveraging the investments that are already made. Overall, utilities should require the infrastructure that supports their business needs as they exist now and as they evolve over time.

Aside from these basic functions, utilities should require other specific functions in an integrated MDM/Billing system. First, the ideal system must be designed from the start to manage high volumes of data. After a few months or years in operation, improperly designed systems will begin to exhibit poor performance. The market will dictate multi-years of data to be available on-line so that customers have access to the same information, and in case any disputes arise. Utilities must be prepared for this.

Once designed to manage the data, the system must have the ability to store and process the high volume of data required. Not as easy as it sounds since as the volume of data increases exponentially, so does the volume of errors. It becomes clear, then, that the validation process is critical. The industry enforces standard validation rules, for all meter data, and the ideal system must adhere to these rules. The system must be able to quickly identify and apply market rules to the data to either automatically cleanse the data or raise an exception. It is essential that the system minimize human intervention to these exceptions. Humans are prone to making more errors. We are also increasingly reminded of the concept of “doing more with less”. This validation process identifies potential lost revenues, provides more accurate data with audit ability, and provides viewing and presentment capabilities. The system must manage and resolve exceptions associated with anomalies and usage data to proactively identify areas of lost revenues and to provide decision support to capitalize on revenue opportunities.

In a decentralized market, consumers have more choices from whom to buy their energy, therefore accurate information becomes a lot more critical. Utilities can’t afford not to have accurate and clean data that can be used for revenue protection and billing calculations. The benefits for such a system are abundant:

- Elimination of manual billing processes – delivering invoice ready data for billing, and internal users and external customers will be provided with enhanced meter/cost data web presentment tools
- Minimized project risk as utilities become capable of embracing and implementing new requirements within specified timeframes
- Maximized return on investment
- Lowered total cost of system ownership
- Increased sales opportunities
- More accurate forecasts
- Reduced market risk
- Accelerated revenue
- Reduced customer service costs.

The advantages of such a system spill over into other areas, as well. For example, utilities can use the vast data warehouse to mine the information for future initiatives not yet defined. They can forecast how much energy they will require in using historical information and analyzing trends in geography and population growth. They will also be able to use this information for distribution planning purposes, thus enabling energy companies to plan for future equipment needs within the distribution network. This type of planning could save companies millions in equipment purchases by extending the service life of equipment and at the same time improving the efficiency and reliability of their network.

MDM AT WORK

One of the leading energy distributors in North America – we’ll call them Acme Energy – has an intrinsic understanding of the importance of meter data management (MDM) and is therefore positioned to support the market like no other service provider. It has more than 2 million meters serving residential, commercial and industrial (C&I) customers. The company manages the lifecycle of meters and instruments, and it also processes interval data (15-minute interval) for approximately 3,000 of its commercial and industrial customers, in order to generate billing determinants to an interfacing legacy billing system.

In an effort to reduce energy costs and reduce the number of power plants needed, one of Acme’s key markets is implementing a large scale automated meter reading (AMR) system that will be fully in place by 2010. This means that 4.5 million meters need to be replaced with smart meters by then. In order to comply with this mandate, electric utilities need to either buy or build their own meter data management solution to work with these new meters. This new solution must be able to work with dramatic increases in data volume in conjunction with decreased delivery times to users of that data to enable effective demand response.

Even before this mandate, though, Acme implemented its own meter data management system for its own internal requirements. The company had been using three legacy systems that served meter data management and meter management business areas on a 30 year old mainframe. So not only did Acme have to contend with working with large data sets, but the cost of operating this mainframe when the company had only a small number of applications residing in it became too burdensome for the IT organization at the time. To reduce this cost, the energy provider sought to migrate the three legacy systems from the mainframe.

At the same time, Acme aspired to improve business processes such as reporting and data access capabilities. The company needed to conduct billing for 8,000 industrial and commercial customers, 3,000 of which are interval meters, produce reports and implement custom processes for servicing meters. For example, inventory needed to be tracked for the 2 million meters that it operates. Finally, Acme wanted a system that was easy to use, scalable and could adapt to any market changes.

RESULTS AND ADDED BENEFITS

Since Acme has completely migrated all of the legacy systems that used to reside in the mainframe, it will experience not only reduced operating costs going forward, but also better access to data than it had in the mainframe – thereby enhancing revenue reporting and monitoring capability.

An added benefit to having better access to data and easier-to-use tools is that users are enabled and don't have to rely so much on IT – especially for ad-hoc reports and mass data updates. Acme is strategically positioned in the market and will offer the MDM solution as an ASP to other electric, water or gas distribution companies in key markets. This move provides Acme with a revenue stream and additional shareholder value. They will be able to expand into other business areas to serve additional customer segments, additional geographic areas and additional commodities.

As for the market, other distribution companies will view Acme as well-positioned to provide these services compared to their competitors.

SUMMARY

The energy industry transition to hourly usage information, dynamic pricing and consequently customer-controlled demand responses is a natural transition to open and competitive markets. As has been experienced in all prior monopolistic industries, increased innovative customer options will come with a more efficient market, which in time, has proven to lead to reduced costs.

Joven Luspo brings more than 20 years of experience in the energy industry to LODESTAR.

UPGRADING YOUR DISTRIBUTION WITHOUT DISRUPTING THE NEIGHBORHOOD

The need to deliver ever-increasing amounts of power, with the reliability and performance customers have come to expect, is a growing challenge to electric utilities.

Increasing electrical loads, congestion, and emergency capacity requirements threaten system performance. Utilities may attempt to solve these problems by increasing voltage levels, which in turn creates another host of problems, including having to replace structures and equipment, acquire new or expanded rights of way and participate in extensive permitting and review processes.

However, manufacturers are developing new conductors that can help utilities address these issues. One option, 3M's Aluminum Conductor Composite Reinforced (3M ACCR), is a high-performance conductor that can provide transmission capacity two to three times greater than existing transmission lines, often without the need for new structures and rights-of-way.

This is made possible by 3M ACCR's core material, which is composed of aluminum matrix composite wires. Each core wire contains many thousand, small diameter, ultra-high-strength, aluminum oxide fibers. The ceramic fibers are continuous, oriented in the direction of the wire, and fully embedded within high-purity aluminum.

Visually, the composite wires appear as traditional aluminum wires. However, compared to steel, the core has less weight, equivalent strength, greater corrosion resistance, lower thermal expansion, and higher electrical conductivity, meaning that it can operate at elevated temperatures with reduced sag. It can be installed as a drop-in replacement conductor on existing transmission lines, with little or no modifications to towers or foundations and without the environmental impact of new towers and expanded rights-of-way. These characteristics may be especially important if other options for uprating have already been exhausted or the line crosses envi-

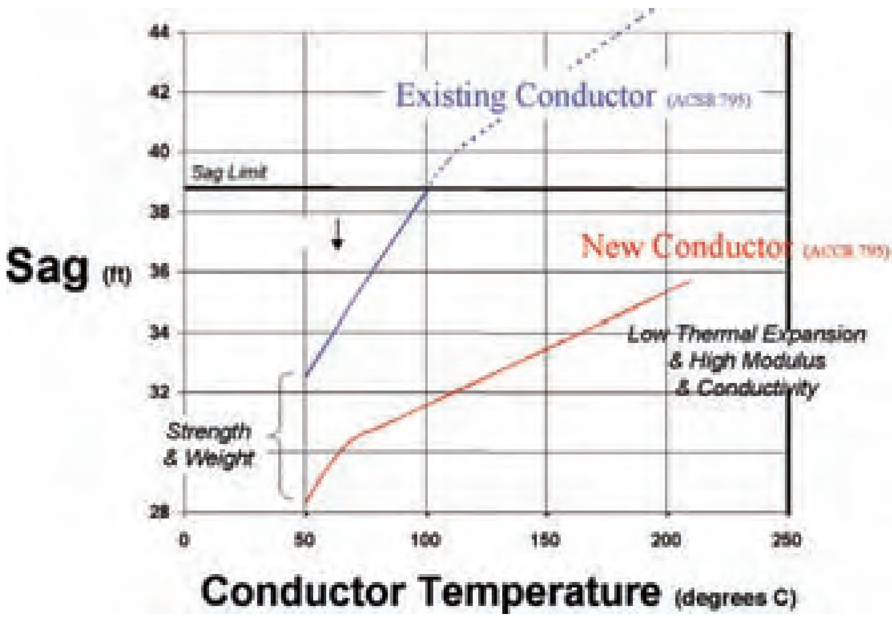


Figure 1: Sag-Temperature Chart Showing ACCR Operating at Higher Temperatures while Exhibiting Reduced Sag Compared to the Same Size ACSR

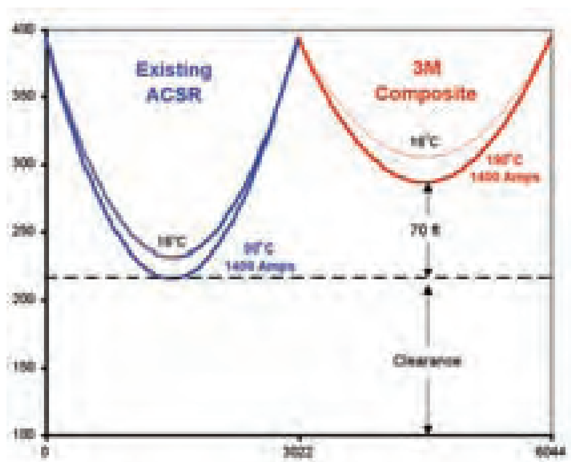


Figure 2: Sag Comparison Chart Showing ACCR Provides Same Ampacity with Less Sag

ronmentally sensitive or densely populated areas, or involves especially long spans.

APPLICATIONS

Thermal Upgrades

The primary use of 3M ACCR is on existing transmission lines in which thermal issues are limiting capacity.

The sag-temperature chart in Figure 1 shows that, when strung to the same tension as an existing ACSR 795 conductor, the initial sag of 795 ACCR is less.

As the conductors heat up, the lower thermal expansion of 3M ACCR permits heating to temperatures of 210 C continuous and 240 C emergency without exceeding the original sag limit while providing a large ampacity increase.

This improved sag performance often allows for further design options, such as using a larger ACCR conductor on existing structures and rights-of-way, reducing tower loads, increasing tolerance to ice loads, and reducing tower heights in new construction.

Long Span Crossings and Changing Clearance Requirements

When clearance requirements change or an upgrade is needed, typically utilities need to raise or replace the towers. However, as an alternative, the utility may be able to replace the existing conductor with 3M ACCR, which can yield 100 to 200% ampacity gains, while maintaining the same conductor diameter, sag, and tower loads, allowing the utility to use the existing structures. Figure 2 shows an example of reducing the clearance of a long span.

In this case, installation of 3M ACCR increased the clearance of a crossing by over seventy feet while maintaining the same ampacity.

2ND GENERATION UPRATING

Today, utilities and design engineers are faced with upgrading transmission lines where "first generation" measures, such as retensioning, raising attachment points, and using conventional steel reinforced replacement conductors have already been taken and the existing structures are at their mechanical limits. For these "second generation upgrades" the only conventional option is to replace or rebuild many or all of the structures. 3M ACCR is a practical alternative to rebuilding or replacing structures because it can be installed on the existing structures and operated at higher ampacities, while maintaining sag clearances.

Conductor Reliability

High temperature behavior of overhead conductors is a relatively new field of study. 3M ACCR and its accessories were developed and tested over a number of years by a team of established conductor and accessory manufacturers, independent test laboratories, and utilities with a focus on reliability. A summary of the tests performed is shown in Table 1.

Table 1: Tests Performed on Various Diameters of 3M ACCR

	477	795	1272	596TW	675TW	774(46/37)
Tensile Strength	x	x	x	x	x	x
Stress-Strain Curves	x	x	x	x	x	x
RT Creep	x	x	x			
ET Creep	x					
Impact	x	x				
Crush	x	x				
Torsion	x	x				x
CTE	x	x				
Core Strain (T.S)	x					
DC Resistance	x	x	x	x	x	x
Fault Current	x	x		x		x
Lightning Strike	x	x				
Aeolian Vibration	x	x	x	x		2006
Sag	x	x	x		x	x
Corrosion		x				
Sheave	x	x	x	x		Active
Post-ORNL	x	2006	x		x	

[illegible]

LABORATORY TESTING AND FIELD INSTALLATIONS

3M ACCR conductors and accessories were tested in laboratory conditions to document their performance under a wide range of mechanical and electrical conditions. To ensure stability, the installed conductor was run through hundreds of cycles and examined for changes in the sag-temperature response. Results were further validated against performance in field installations in which the conductor was run at high temperatures and performance was measured with load cells and data acquisition systems. This validation provides confidence in the numeric values used as inputs to the design software and the relationship of those inputs to the sag behavior in the field under high temperature conditions.

Table 2 summarizes the field testing installations and tests performed.

The field trials indicate that the conductor behaves as intended and forecasted in actual field conditions, verifying the claimed strengths and reliability of the product.

COMMERCIAL APPLICATIONS

3M ACCR is installed and operational on a number of critical utility sites, including generation interconnects and primary paths serving rapidly growing urban areas, downtown businesses and a large commercial airport. In all cases, ACCR has delivered superior performance consistent with design intent.

This technology, proven both in the lab and through commercial applications, allows utilities to accomplish thermal upgrades across long span, environmentally sensitive, or densely populated areas, while saving the time and costs of installing new structures, expanding rights-of-way, and engaging in lengthy public and regulatory processes.

Table 2: 3M ACCR Installation Test Sites

	Voltage	Date	Size	Purpose	Measurements
Xcel Energy	115 kV	2001	ACCR 477	Ice, Cold	Sag
Hawaiian Electric	46 kV	2002	ACCR 477	Corrosion	Visual & Weight Loss
Western	230 kV	2002	ACCR 795	Ice, Cold	Tension & Vibration
Oak Ridge	DC	2002-05	ACCR 477, 795, 675TW, 1272	High Temperature	Tension, Sag, Component Temperatures, Current
National Grid	115 kV	2004	ACCR 590TW	Ice, Cold	Tension
Salt River Project	69 kV	2004	ACCR 795	High Temperature	Tension, Ambient, Current
Bonneville Power	115 kV	2004	ACCR 675TW	High Temperature	Tension, Ambient, Current
Western	230 kV	2004	ACCR 1272	Installation	Tension, Ambient, Current
San Diego (EPRI)	115 kV	2005	ACCR 795	High Temperature	Tension, Ambient, Current, Sag

SPANISH UTILITY TURNS CUSTOMER BILLS INTO A STRATEGIC ADVANTAGE WITH EDP

By Chris Stone, President & CEO of StreamServe Inc.

Utilities today – especially those in Europe where deregulation is already a reality – have prioritized enhancing relationships with their customers in order to maintain revenue growth. Although deregulation is not as firmly entrenched in the United States, forward-thinking American utilities understand the critical importance and brand enhancement benefits of satisfying their constituents by providing a positive customer experience across all touch points, including bills and correspondence, customer service, outage and repair services, as well as self-service via the web.

One way leading utilities have improved the customer experience is by implementing an Enterprise Document Presentment (EDP) system. The idea behind EDP is pretty straightforward, but the results can be downright sensational. In short, EDP enables the automated creation and presentment of enterprise documents in any format via any channel to customers, suppliers and business partners. What this means is that organizations can retrieve and integrate information from a variety of systems – CIS, ERP, CRM, SCM, legacy, etc. – to create, present and distribute clear, personalized and persuasive customer documents to the recipient in the format that best suits their needs.

An EDP solution integrates with virtually all enterprise applications by supporting virtually all communication protocols and data formats. Back-end systems may change or new companies may be acquired, but easy integration means that document production remains constant and consistent.

In the past, utilities thought of billing only in terms of providing payment information to customers. However, billing affects everything from the ROI of IT to the relationships with regulators, directors and shareholders. Upgraded billing capabilities can reduce operational costs, as well as drive incremental revenue for those utilities that offer a portfolio of services. Companies that adopt EDP find it helps turn bills from a summary of transactions into a competitive advantage. The most visible benefit of adopting an EDP solution is vastly improved bills that help customers clearly understand what they've consumed and the associated costs.

Hidroeléctrica del Cantábrico is looking at modernizing both their customer billing and generation options, like this wind farm in southern Spain.

These bills also provide an easily adaptable vehicle for meeting regulatory information requirements, for demonstrating the utility's commitment to its community obligations, and for presenting relevant cross- and up-sell offers. However, the positive impact goes far beyond just the bills.

Well-informed customers make fewer calls to customer care, and when additional services or packages are offered, they are more inclined to take advantage of them, driving incremental revenue. For those customers who need telephone consultation, EDP enables the customer service representative to immediately pull up an exact copy of the bill to get to the heart of the matter faster, resulting in shorter call duration.

EDP also delivers savings in bill distribution. Accepting a raw data feed from enterprise systems, it produces and outputs bills in whatever format the customer prefers – print, electronic, Web, etc. Customers can select their preferred delivery format, but organizations can drive the adoption of electronic delivery via targeted messages on paper bills; greatly reducing print and postal cost.

EDP IN ACTION

One example of how an EDP solution can enable a utility to better leverage its customer communications is provided by Hidroeléctrica del Cantábrico, a Spanish utility that supplies electricity and gas to more than 1.3 million customers, generating nearly 10 million documents annually. In addition to customer bills, it also prints internal communications, such as bonus policies, departmental documents and contracts. The company uses StreamServe Utilities to control the composition, distribution and presentment of all of these documents regardless of the recipient, for greater efficiency and ease of comprehension.

Hidrocantábrico saw tremendous promise in taking advantage of their most consistent customer touch point, the monthly bill. As they undertook an initiative to improve this often overlooked customer touch point, they developed some lofty goals for any potential technology provider: They wanted to improve the quality of communications with their customers; enhance their brand; reduce costs, and integrate cross-promotional offers into their communications so they could enhance the value of their customer relationships. And, oh yes, they wanted to do all this with a solution that was compatible with SAP, Windows and Sun Solaris.

Their requirement was that any implementation would have to be an integrated solution for the design, personalization, distribution, and archiving of business documents, while reducing operational costs by leveraging new distribution channels. After evaluating numerous technologies, Hidrocantábrico concluded that StreamServe Utilities EDP solution was a perfect fit to address their requirements.

It proved to be a profitable conclusion.

"Thanks to StreamsServe Utilities, we've been able to carry out enormously profitable marketing campaigns because

Continued on Page 32

NEW ENERGY REGULATIONS TO IMPACT THE COMMERCIAL TRANSFORMER MARKET

The continual and rapid escalation of U.S. energy consumption was a major driving force behind the enactment of the first comprehensive revision of the domestic energy policy in over 14 years.

This article addresses the implications of the new energy policy on the electrical industry, with specific focus on the commercial transformer segment. Distributors and end users will need to understand the impact of this new regulation as they prepare for new construction and building maintenance projects in 2007.

2005 ENERGY POLICY ACT

Signed into law on August 8, 2005, President Bush signed into law the 2005 Energy Policy Act (EPAct 2005). EPAct 2005 addresses the conservation and development of newer energy sources through an extensive set of new regulations that stretch from hybrid cars to commercial lighting installations.

Today, the United States leads the world in energy consumption by a large margin using over 3.7 trillion kilo-watt-hours and over 7.3 billion barrels of oil per year. As a gauge, U.S. oil consumption is 233% higher than the number two consumer, China.

That thirst for energy is growing. Unabated, U.S. energy consumption is forecasted to continue climbing by 32% over the next 14 years, which is more than double the increase experienced since 1973. With today's elevated energy prices, EPAct 2005 seeks to quell this thirst and tap into renewable, domestic sources of energy for the long-term viability and stability of the U.S. economy.

EPACT 2005 MANDATES HIGH-EFFICIENCY TRANSFORMERS

EPAct 2005 mandates that distribution transformers meet specific efficiency levels starting January 1, 2007. The new levels use NEMA TP-1 rating standards as a reference for establishing a higher-efficiency rating for distribution transformers. The law closely mirrors TP-1 but is not based verbatim on TP-1. The TP-1 efficiency ratings for Dry-Type distribution transformers are detailed in the chart below.

Production of non-compliant models must be halted by the end of 2006. Unfortunately, the higher-efficiency transformers cost more to build than the non-compliant models.

REFERENCE CONDITION	TEMPERATURE	% OF NAMEPLATE LOAD
Low Voltage	75°C	35%
Medium Voltage	75°C	50%

SINGLE PHASE EFFICIENCY				THREE PHASE EFFICIENCY			
KVA	LOW VOLTAGE	MEDIUM VOLTAGE		KVA	LOW VOLTAGE	MEDIUM VOLTAGE	
		≤60 kV BIL	>60 kV BIL			≤60 kV BIL	>60 kV BIL
15	97.7	97.6	97.6	15	97.0	96.8	96.8
25	98.0	97.9	97.9	30	97.5	97.3	97.3
37.5	98.2	98.1	98.1	45	97.7	97.6	97.6
50	98.3	98.2	98.2	75	98.0	97.9	97.9
75	98.5	98.4	98.4	112.5	98.2	98.1	98.1
100	98.6	98.5	98.5	150	98.3	98.2	98.2
167	98.7	98.8	98.7	225	98.5	98.4	98.4
250	98.8	98.9	98.8	300	98.6	98.6	98.5
333	98.9	99.0	98.9	500	98.7	98.8	98.7
500	—	99.1	99.0	750	98.8	98.9	98.8
667	—	99.2	99.0	1000	98.9	99.0	98.9
833	—	99.2	99.1	1500	—	99.1	99.0
				2000	—	99.2	99.0
				2500	—	99.2	99.1

NEMA class 1 efficiency levels for dry-type distribution transformers

Builders and contractors need to be aware of these cost implications and adjust their budgets accordingly. While the noncompliant models are cheaper to buy, they do cost more, in the long term, due to the higher energy costs incurred to run them in addition to the increased pollution levels they cause. The higher cost of the compliant transformers however, is offset by reduced usage costs through lower energy bills by wasting less electricity.

The rationale for the mandate is quite clear. While standard transformers operate at 90% to 95% efficiency while under full load, their efficiency drops at lighter loads. This is due to inefficiencies in the transformer's core, a main component of the transformer. The losses in the core remain the same throughout the transformer's operating range. At 100% load, the amount of comparative loss is negligible. However, at reduced loads, the same amount of energy loss represents a higher percentage of energy being wasted. Unfortunately, average transformer loads run between 50% and 34% of the transformer's total capacity.

With the majority of the electricity used in this country being run through transformers at these lower loads, massive amounts of energy are being wasted.

IMPROVED EFFICIENCIES DURING AVERAGE LOADS

Compliant transformers are able to maintain NEMA Class 1 efficiency levels at 35% load. This is accomplished by using higher-grade grain oriented steel in

Continued on Page 32

Spanish utility

Continued from Page 30

profitable marketing campaigns because it has allowed us to effectively cross-sell other products and services offered by our company," said Valentín Vallina, information systems technical manager of Hidroeléctrica del Cantábrico. Hidroeléctrica del Cantábrico offers services associated with the production, transport, transformation and distribution of electrical energy, and possesses businesses related to gas, renewable energy and telecommunications.

Hidrocantábrico was able to rapidly implement StreamServe's EDP solution into their environment, thus optimizing the production and distribution of business documents, facilitating customer-specific marketing offers, and electronic invoice distribution.

Another advantage of StreamServe Utilities is that it offered data source independence and, therefore, no modification had to be made to the standard SAP – ISU version. In addition, Streamserve's EDP solution is certified for the receipt of SAP data in compressed RDI format, providing the ability to rapidly design and generate invoices, contracts and any other documents coming from SAP applications for distribution across multiple channels.

"There were several compelling reasons we chose StreamServe," said Mr. Vallina. "The rapid speed of implementation, the versatility in using new channels such as SMS, the connectivity of StreamServe Utilities, and the high degree of professionalism demonstrated by the StreamServe team in Spain were all important factors."

Hidroeléctrica del Cantábrico consolidated electricity and gas consumption into a single invoice, while classifying the invoices by distinct criteria (postal code, invoicing summary, etc.) inserting optical labels and providing total flexibility for design changes.

Another key advantage of the solution was its ability to preserve the intelligence of the life cycle in the commercial documentation of Hidrocantábrico, assuring independence from its printing supplier. This advantage contains an ROI that is much more compelling than might be initially apparent: Another StreamServe customer has indicated that its EDP solution reduced their print production costs by 50 percent because they were no longer locked into a single print vendor.

Equally as important, Hidroeléctrica del Cantábrico improved its corporate image on each printed document and optimized its client relationships by establishing a new marketing channel through the invoice itself.

Now, personalized cross-promotional marketing messages can be dynamically inserted into invoices and other attached documents without a costly investment in personnel and commercial technicians. The company has also achieved significant cost savings on paper and postage, since these campaigns are now inserted into the invoice envelope instead of requiring a separate mailing.

New regulations

Continued from Page 31

the core rather than the standard non grain oriented. Grain oriented steel's thinner gauge and purer metallic material quality reduces heat caused from eddy currents by limiting the current's direction in which it can flow. This narrowing of the magnetic field into a thinner profile also reduces the canceling effect of opposing currents.

The compliant transformers will cost more than their lower-efficiency predecessors due to the higher price tag for grain oriented steel, additional labor and higher raw material costs. Unlike the market for standard Cold Rolled steel, demand for grain oriented steel is at an all-time high. This has been caused by an increased usage in today's energy-efficient products, such as hybrid cars, and from government regulations, like EPAct 2005. This heightened demand has quickly outpaced the stagnant global supply chain of grain oriented steel, causing unprecedented price hikes.

Beginning October 2005, prices for grain oriented steel have risen nearly 50%. Moreover, grain oriented steel's smaller thickness requires more individual pieces to be used in the transformer to achieve the required total stack height. This requires additional labor compared to using the thicker material. In addition, other raw material markets have experienced record price hikes starting last fall. Sola/Hevi-Duty offers transformer windings in either aluminum or copper. Since 2004, aluminum and copper have experienced price growth of 46% and 91%, respectively. Supply and demand has caused much of the escalation. However, investment speculators and opportunists have also lifted metal market prices as they seek portfolio diversification and chase returns that the stock market has not seen in years.

BENEFITING FROM HIGHER ENERGY EFFICIENCIES

Increasing the energy efficiency of a transformer allows the unit to operate at the same level of power with less energy being wasted in the process. This has a large impact on the consumption and distribution of energy because the reduction in energy usage improves the nation's energy independence, reduces environmental impacts, lessens infrastructure investment, and protects and strengthens the economy.

Decreasing usage through reduced waste by just .03% over the next 20 years cuts the need for new power generation by 60 to 66 million kw. That drop would eliminate the need for construction of 11 new 400-megawatt power plants by 2038. Electrical power generation accounts for 35% of all U.S. emissions of carbon dioxide, 75% of sulfur dioxide and 38% of nitrogen oxides.

With higher-efficiency transformers, the country will see reduced emissions of CO2, NOx and Hg of 678.8 Mt, 187.7 kt and 6.48 t over the next thirty years. Curbing energy imports also bolsters the U.S. economy by reducing the current $65 billion trade deficit and mitigating fuel prices through decreased demand.

EPACT 2005'S TRANSFORMER DEFINITIONS

EPAct 2005 applies to "distribution transformers" which are defined as:

- Has an input voltage of 34.5 kV or less
- Has an output voltage of 600 V or less
- Is rated for operation at a frequency of 60 Hz
- Has a capacity of 10 kVA to 2500 kVA for liquid-immersed units and 15 kVA to 2500 kVA for dry-type units.

HIGH VOLTAGE LAB SPARKS INTEREST ON DIRECT CURRENT TESTING

Kinectrics has opened a new facility to provide DC testing services with particular capabilities for DC arc hazard testing that have never before been available to the power industry.

Kinectrics purchased laboratory equipment and created an original technical design for DC arc testing that is exclusive to its High Current Laboratory. "We made something simple and practical that can do the job," said senior Kinectrics engineer Carl Keyes, of the service.

With this new facility, Kinectrics has expanded to handle the full spectrum of both AC and DC arc testing. Further, with a long established background in comprehensive AC testing, Kinectrics has unique expertise in the controlling and measuring of electrical arcs to produce data that can be used to quantify the associated hazards.

"That is the special ability we bring to this work," emphasizes Keyes. The similar lab set-ups used for both DC and AC arc testing also provide the opportunity to apply cross-correlations and establish quantifiable differences related to test data.

"The equipment is working well. With this addition to our high current test facilities, we now have the flexibility of performing a wide variety of high current DC testing at low voltages (below 700 VDC)," says Keyes. "We can also perform high current 3-phase AC testing over a range of source voltages below 700 VAC. Kinectrics' additional strength is in accurately measuring arc radiant energy using our high speed calorimeters and digital data acquisition equipment."

Bruce Power has promoted the development of DC Arc testing at Kinectrics. They recognized the need for improved capabilities in the industry and initiated the project in this area. In parallel, the IEEE has formed a committee to raise funding for arc testing in general, including further DC arc testing.

Injuries due to burns from the radiated energy of DC arcs are a serious safety concern. Examples of specific DC arc hazard locations include: battery banks in transmission and generation stations and transit power rails that utilize DC current. Kinectrics' purpose in expanding its test capability is to facilitate the gathering of new knowledge on arc hazards to aid in the selection of appropriate personal protective clothing and equipment. "It's all about safety," adds Steve Cress, principal engineer and Kinectrics T&D Department Manager, noting that "industry studies have found that the majority of deaths in electricity-related incidents have been due to burns".

These are photos of only one of the two rectifier units (each is rated at 12,000 A DC continuous). Placing the two rectifiers in parallel, short bursts of up to about 30,000 A DC can be achieved. Both the epoxy encapsulated transformer and rectifiers are water cooled.

The initial demonstration was carried out at Kinectrics on February 2, 2007. The session was attended by several representatives from the IEEE, Bruce Power and the CANDU Owners Group (COG). The IEEE reps who attended the initial demo were very impressed with the results and remarked that now in the 21st century, "the industry is finally starting to acquire knowledge" in the important area of DC arc hazards.

Kinectrics' DC testing capability was developed rigorously over a six month period. "We took baby steps," says Keyes, "in gradually increasing the current in the trial runs." The system is modular and can be operated in parallel for higher capacity. When fully assembled, the DC test equipment will deliver a maximum of 30,000 amps and up to 800 volts.

"We will analyze the resulting data from a matrix of tests with varied parameters, in order to approximate real-world conditions," said Keyes.

INVESTING IN LIFE-CYCLE: A NEW METHODOLOGY

By Larry Haffner, P.Eng Sr. Manager – Asset Management & Thomas V. Ta, P.Eng. Sr. Engineer, Asset Performance & Asset Health, British Columbia Transmission Corporation

This article proposes a probabilistic methodology for forecasting an appropriate level of investment in sustaining capital for the Asset Management sector of an electric utility. This is a valuable practice for most utilities.

The methodology is a new way of looking at Asset Management within electric utilities, as well as for shareholders and regulators. The methodology is designed to:

• Model life-cycle investments for station and transmission assets based on their historical failure rates.

• Provide the life-cycle length of these assets and the associated implications for investment planning.

• Offer a sensitivity analysis of sustaining capital investment against performance levels of the assets.

For simplicity, this paper explains the methodology by focusing on the sustaining capital portion of assets, i.e., the existing assets. The growth component of assets can be added to the methodology as required. Sustaining capital is also referred to as replacement capital and life extensions in some electric utilities.

KNOWING YOUR COMPANY'S ASSETS

Electric utilities are capital intensive. The life cycles of utility assets range from 30 to 50 years and often longer, depending on the equipment.

Like most utilities in North America, the British Columbia Transmission Corporation (BCTC) experienced its highest growth in the 1960s and 1970s. That past growth will have a profound impact on life-cycle investments over the next two decades, because of the investment required to maintain the accumulated assets.

BCTC is a typical electric utility in terms of its asset composition. It has 33 predefined asset classes. Within each asset class, there may be several asset types. For example, 500 kV circuit breakers is one asset type within the circuit breaker asset class. Table 1 shows the types and values of assets for BCTC.

Table 1: Asset Data for BCTC

Asset Class	Current Asset Value	Asset Distribution (2006, in millions)
Circuit Breakers	$537	4.80%
Disconnects	$337	3.01%
Transformers	$855	7.64%
Instrument Transformers	$145	1.29%
Shunt Reactors	$266	2.35%
SCADA and P&C	$360	3.22%
Spill Containment Systems	$537	4.79%
HVDC Substation	$264	2.36%
Conductor Span	$2,273	20.31%
Metal Structure	$2,468	22.06%
Wood Pole Structure	$688	6.15%
Cables	$1,633	14.50%
Others	$827	7.52%
Total	$11,190	100%

The sheer number of assets and their long life-cycles require business strategies with a long-term view. A life-cycle view is one of the key factors in making investment decisions in Asset Management, so it is critical that sustaining capital plans consider and incorporate the impacts of the long life-cycle of electric utility assets.

Asset investment decisions have both short and long-term impact on the revenue stream, because the financing spans over the life of the assets. For many electric utilities, a long-term business cycle plan for sustaining capital is around ten years; a short-term plan is typically 1 to 2 years. Short-term investments are usually committed to the shareholders and regulators. A good asset management strategy requires complete life-cycle knowledge, as well as a short-term plan.

Both shareholders and regulators are interested in the impact of investment on performance of the assets. Correlating investment with performance is a key business driver for many electric utilities. Forecasting investment is an important part of Asset Management strategy because investment:

- Impacts the cost of the assets during their whole life-cycle.
- Influences electricity rates and net income for the financing period of assets.
- Impacts the performance and, therefore, the health of assets during their life-cycle.
- Provides transparency and repeatability in linking investment decisions with performance.

METHODOLOGY: FORECASTING SUSTAINING CAPITAL

The following is an overview of the methodology for forecasting sustaining capital (hereafter "the Methodology").

It describes the criteria for the methodology, including failure rates and expected end-of-life; the asset demographics needed to graph data for the methodology (including example graphs); and how investment levels are forecasted based on that data.

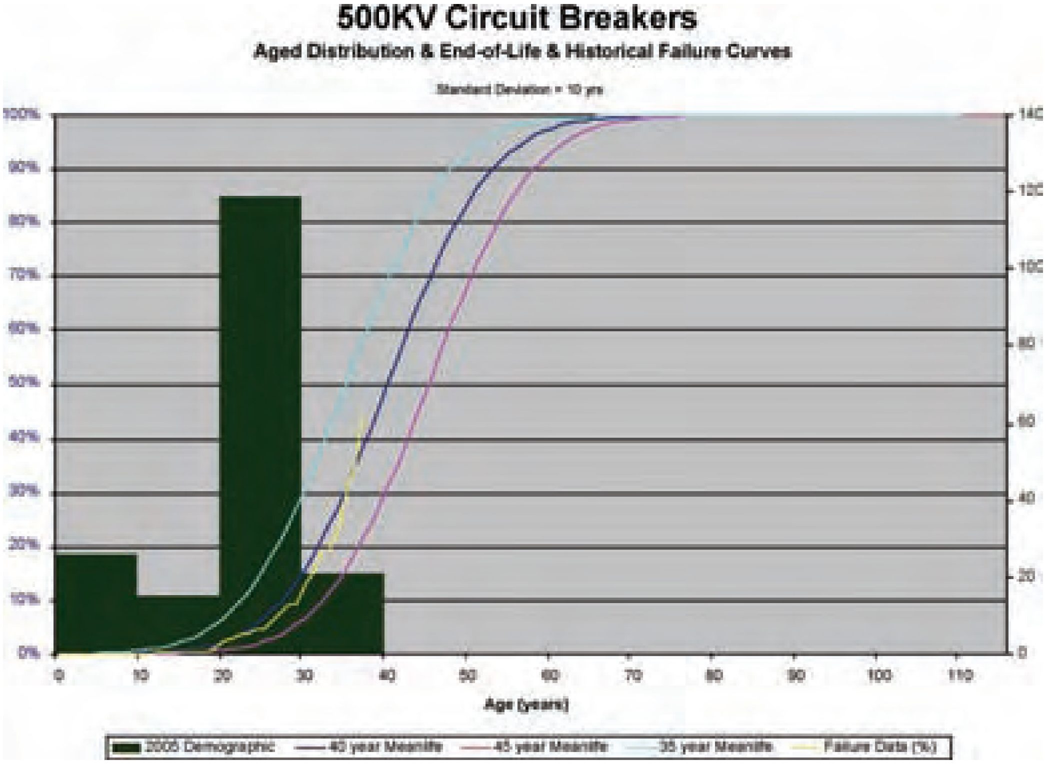


Figure 1: Asset Inventory, Age Profile, Value, and End-of-Life Curve (with fitted Normal Distribution curve based on actual data).

CRITERIA FOR METHODOLOGY

The Methodology is derived from the principles of Normal Distribution and Central Limit Theorem. This Theorem states that the mean of any distribution with a finite means and variance follows the Normal Distribution, with a few events at the extreme ends and many in the middle (the standard "bell curve").

The Mean Life (or mean lifespan) refers to the point at which 50% of the assets in a class have been replaced. In the Methodology, the failure rates of electric utility assets are assumed to follow a Normal Distribution. In other words, a small percentage of assets fail during the early life cycle, a few last beyond the average expected life span, but the majority fail within their mean life.

Note: The Weibull curve used to model a lifespan of electric utility assets – also known as the "bathtub curve" – was not chosen for the Methodology because the costs of replacing infant failures are covered by manufacturers under warranty. Such infant failures do not constitute end-of-life for the equipment and have no significant impact on investment, because the equipment is repaired or replaced by manufacturers.

End-of-life means an asset can no longer operate economically to its original design due to:

- Technical obsolescence.
- Lack of original equipment manufacturer (OEM) support.
- No spare parts.
- No longer meets current safety rules.
- No longer meets current environmental or regulatory requirements.
- Has reached proven end-of-life as per industry-accepted knowledge.
- Unacceptable failure rates resulting in higher maintenance costs.
- Maintenance costs exceeding replacement costs.
- Catastrophic failure.

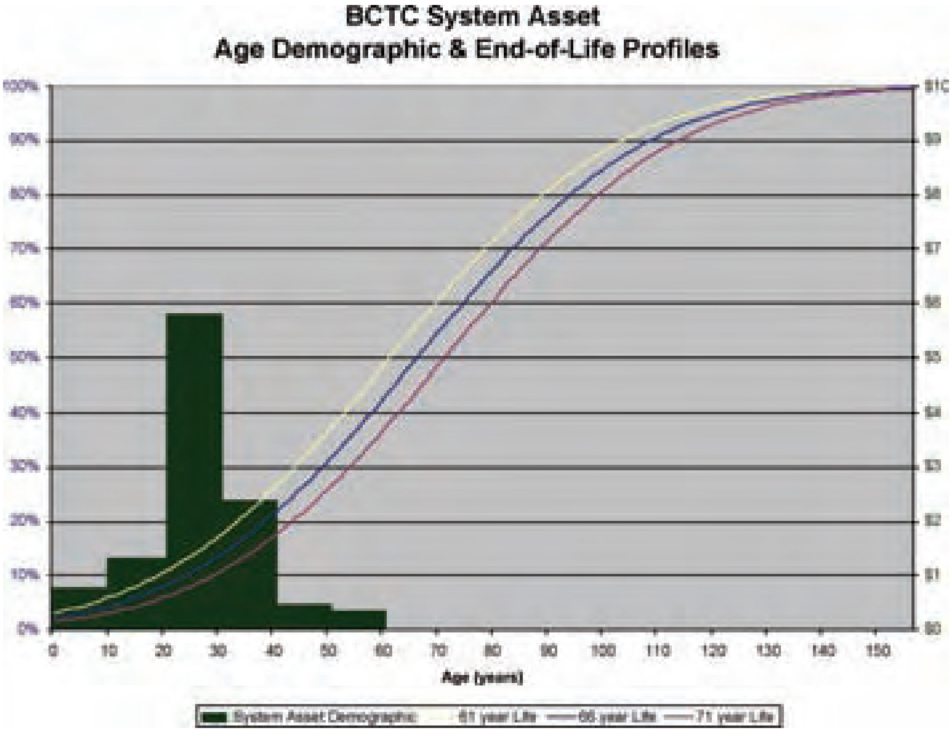


Figure 2: Asset Inventory, Age Profile, Value, and End-of-Life Curve (based on Standard Normal Distribution curve).

COLLECTING DATA

The Methodology requires the following data collection:

• Demographic data for each asset type and class. Some examples of asset types include Air Blast, Oil-filled, or SF6 230 kV circuit breakers. The asset class comprises all types of circuit breakers for all voltage classes.

• Historical failures and retirements that show end-of-life for equipment. In other words, the assets' decommissioned dates are used to track their end-of-life for any reason.

• Replacement costs for assets in present value.

For many utilities, extracting old data can be challenging. In cases where it doesn't exist, it's helpful to estimate the age distribution of assets. For instance, it's usually easier to retrieve the commissioned dates for transmission lines than it is for protection and control systems. Therefore, you can estimate the commissioned dates of the latter based on the commissioned dates of the former. In other cases, it may make sense to take a sample of a large population of assets. For example, thousands of 60 kV wood poles may have no commissioned dates. By extrapolating from a sample, you can estimate the age profile of all 60 kV wood poles.

GRAPHING DATA

The data on demographics, inventory, and replacements (based on historical records) are then represented in ten-year segments. This matches a typical investment business planning cycle for a utility.

Figure 1 shows an example of age distribution, end of life, and historical failure curves for 500 kV circuit breakers.

Figure 1 shows:

• Number of assets on the right side Y-axis.
• End-of-life probability on the left side Y-axis.
• Age on the X-axis.

As an example, the bar chart in Figure 1 shows that 120 of the 500 kV circuit breakers are between 20 and 30 years of age. The spike in the asset demographic is typical for BCTC (and most other utilities) due to high growth rates in the 1960's and 1970's.

The dark blue curve on the graph shows a Normal Distribution end-of-life for 500 kV circuit breakers with a mean life of 40 years and a standard deviation of 10 years. (The light blue and maroon curves indicate the sensitivity analysis of assets with a mean life of 35 and 45 years, respectively.) The dark blue curve tracks very closely to the actual end-of-life (the yellow curve) for 500 kV circuit breakers in BCTC, based on a 40-year historical record.

Tracking is critical because it validates the Methodology. As more data becomes available, more accurate mean life and standard deviations can be calculated.

Graphs of an entire asset class, such as circuit breakers, can be created by totalling data for all circuit breakers for all voltages and rolling them up together to create a curve. To ensure meaningful forecasting data for particular asset classes, only assets with similar costs and mean life should be rolled up together.

An asset graph for the entire system can be created by rolling-up all asset classes together. Figure 2 shows the asset demographic and end-of-life profiles for BCTC's entire system of 33 asset classes.

Figure 2 shows:

• Value of assets expressed in $ billions (in 2005 dollars) on the right side Y-axis.
• End-of-life probability on the left side Y-axis.
• Age on the X-axis.

As an example, the bar chart in Figure 2 reveals that about $6 billion of assets are 20 to 30 years old, and about $2.5 billion of assets are 30 to 40 years of age.

This means that about $8.5 billion (or 77%) of the total asset value of $11 billion is between 20 to 40 years of age.

Figure 2 reveals some important data:

• A significant and long-lasting investment bubble. As assets age, the failure rate increases.

• The mean life curve for the assets (blue curve), which is 66 years in this example. About 20% of assets reach their end-of-life around 40 years (cumulative failure rate), about 50% by 66 years, and about 80% by 90 years.

• A sensitivity analysis of the mean life of assets of 61 and 71 years (yellow and maroon curves), taking into account a 10-year standard deviation.

FORECASTING INVESTMENT LEVELS

Using the data from Figure 2, the levels of investment for sustaining capital can be forecasted, as shown in Figure 3.

Continued on Page 38

New Methodology
Continued from page 36

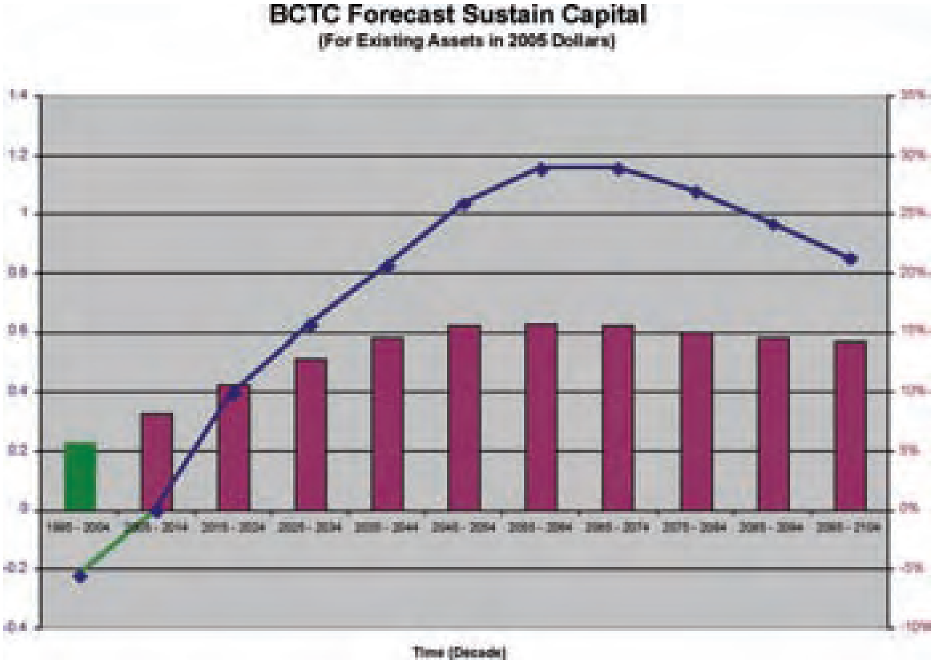


Figure 3: Forecasted levels of Investment for Sustaining Capital for the next 100 years.

Figure 3 shows:

• Percentage of retired assets on the right Y-axis.

• Percentage of capital change on the left Y-axis relative to the current decade (2005-2014).

• Time expressed in decades on the X-axis.

The green bar in Figure 3 also presents the actual retirement percentage for the previous decade.

This forecast reveals that investments will need to be increased sharply over the next five decades to replace retiring assets. The increasing investment trend will continue for the next five decades before tapering off. Levels of investment need to be higher for future decades in order to maintain the current level of reliability. For example:

• For the next decade (2015-2024), the sustaining investment will increase over 40% from the current decade (2005-2014).

• Two decades later (2025-2034), the sustaining investment will increase approximately 60% from the current decade (2005-2014).

• Three decades later (2035-2044), the sustaining investment will increase over 80% from the current decade (2005-2014).

• The levels of sustaining capital investment will continue to increase for the next five decades.

This represents significant, long-term investment, because assets added to the system during the high-growth period of the 1960s and 1970s will have to be replaced as they reach end-of-life.

Since BCTC is a typical electric utility in terms of asset demographic, the outcomes of forecasting sustaining capital will likely be similar for others as well.

CORRELATING INVESTMENT WITH PERFORMANCE

It's impossible for a utility to accurately forecast future investment needs, because changes in technology and asset management may change the forecast in unpredictable ways. However, the Methodology provides a strategy for ensuring that the likelihood of substantial cost increases in the future can be anticipated and mitigated before it's too late.

Assuming that historical maintenance strategies and practices will remain relatively constant, historical failure rates can be used to forecast end-of-life curves for assets. Therefore, if investments were made to the level forecasted for sustaining capital, the performance of assets will remain fairly close to historical figures.

However, note the significant increases in the levels of investments for each decade in order to maintain the current reliability. Reliability is a measurement of equipment downtime using BCTC's System Average Interruption Duration Index (SAIDI).

For BCTC, about 30% of reliability is directly attributable to asset performance, such as equipment failures. The remaining 70% is indirect and non-asset-related, such as those caused by fallen trees and severe weather (that is, equipment failures unrelated to the lifespan of the equipment). Creating asset management strategies requires a holistic approach that addresses both the asset and non-asset-related reliability causes.

For BCTC, the last 10-year average SAIDI attributable to equipment or asset performance is 0.6 hours. Table 2 shows the relative performance expectation of assets – a correlation of levels of investment in sustaining capital programs with SAIDI attributed to equipment performance. This table is derived from a larger spreadsheet of a reliability and investment model, based on current maintenance strategies and processes. Some of the assumptions on which the spreadsheet data are based include:

- More assets close to retirement = more breakdowns.
- Increases in defective equipment = increased capital costs and emergency work
- Equipment past retirement = less reliable; replacement required next decade.

Table 2 shows that, if sustaining capital investments for the next 10 years match the forecasted levels, the equipment performance-related SAIDI increases slightly over the historical value. However, if the sustaining capital investments for the next 10 years are reduced to the last 10-year level, the equipment performance-related SAIDI increases substantially. This shows that increasing sustaining capital investments does not decrease SAIDI, but keeps it relatively stable.

For example, the investment level of $870M in the next decade (an increase of $193M from the current decade) will still result in a net SAIDI increase from the base case of 0.6 hours to 0.8 hours. This is because a rate of 8.22% for asset replacements is not enough to compensate for the retirement of all aging assets.

Table 2 illustrates the significance and magnitude of investments needed in the decades ahead to deal with the age demographics of assets in electric utilities.

demographics of assets in electric utilities.

To maintain current levels of reliability and to offset increased risks of aging assets, asset management must include non-asset-related reliability strategies.

Table 2: Correlation of Sustaining Capital Levels with SAIDI

Scenarios	Sustained Capital (present value in millions)	% of Assets Retired	Equipment Performance (SAIDI in hrs)
(Last 10 Years)	$677	5.85%	A. Base Case 0.68
(Next 10 Years)	$870	8.22%	B. Forecasted Level 0.91
(Next 10 years)	$677	5.86%	C. Historical Level 1.43

CONCLUSIONS

The significant outcomes from the Methodology are:

• Age demographics of assets will have a significant impact on life-cycle investments. In particular, the investment bubble from the 1960s and 1970s will have a lasting impact on life-cycle investments.

• The investment strategy must reflect the life-cycle of utility assets, such as the very long life-cycle of transmission assets. The Methodology results in a 100 year and beyond life-cycle view.

• Correlation of the levels of investments with asset performance will create transparency for shareholders and regulators.

Above all, to continue current levels of reliability, asset management strategies must address the impacts of the forecasted levels of increasing sustaining capital investments. If a high investment trend continues, the impact will be higher electricity rates for customers. Forecasting allows a utility to develop a strategy in advance that will prevent or reduce the need to increase rates in the future.

To mitigate rate increases in the decades ahead, BCTC has been developing and implementing asset management strategies that focus on:

- Extending the life of assets.
- Replacing assets at lower costs through a precise capital plan – for example, replacing a station circuit breaker, but keeping the concrete foundation and control wires of the circuit breakers where possible.
- Implementing procurement strategies that lower the costs – for example, a bulk equipment purchase program.
- Developing maintenance strategies that increase the lifespan of assets.

Thomas Ta is a Senior Asset Performance and Asset Health Engineer at British Columbia Transmission Corporation (BCTC). He has developed a number of tools for helping Asset Management in BCTC, including Asset Health Index, Ranking of Delivery Points, and Systematic Failure Rate Analysis.

RELIABILITY ANALYSIS OF SUBSTATION SWITCHING CONFIGURATIONS

By Michael Sidiropoulos, M. Eng.

Substation reliability is critical for overall system reliability. Failure events at main grid substations can lead to multiple outages with possible cascading consequences and widespread loss of customer load. This article presents a review of the existing literature of substation reliability analysis, which shows that considerable knowledge has been gained from the application of primarily analytical methods. The complexity, however, of substation switching operations does not lend itself to pure analytical treatment. Simulation methods are more suitable as the mathematical modeling of the relationship between events and outcomes is not always possible.

The article expands the existing methodology and describes a method to perform reliability evaluation of substation switching arrangements based on the sequential Monte Carlo simulation. The method is applied in the reliability analysis and comparison of the most commonly used substation switching configurations. The article shows how the results of the analysis can be applied to model substations in a composite system reliability evaluation.

I. INTRODUCTION

Switching substations are an important component of main grid and subtransmission systems.

Their impact on overall system reliability can be very significant and the selection of a particular switching configuration will influence the cost and performance characteristics of any system development scheme. The objective of this article is to determine the reliability characteristics of the most commonly used switching configurations, leading to a better rationalization of the balance between cost and performance.

This is not an unexplored area. Several papers have made important contributions by exploring analytical methods and ideas. Reference 1 considers the impact that substation failure events have on the contingencies of connected lines and generators which should be included in the reliability evaluation of a composite system. It describes algorithms which simulate various failure modes of substation components, determine the resulting contingencies and compute the appropriate reliability indices. The results can be used to assess the reliability of the substations themselves and as input data to the composite system reliability evaluation.

Reference 2 proposes a practical and effective method based on the outage table approach to analyze the reliability of bus configurations. It considers the random failures of substation equipment and determines the probability and frequency distributions of derated substation capacities. Reference 3 presents an algorithm which focuses on post-failure switching actions intended to reconfigure the substation in order to prevent or recover curtailed load. Reference 4 uses a linear programming and state enumeration approach to determine the LOLE resulting from substation component failures and to relate substation reliability to the cost of lost energy. Reference 5 uses a simulation method and an analytical method to determine the reliability of a six circuit single bus substation and concludes that the simulation method can provide additional indices which can not easily be obtained with analytical methods.

The method proposed in this article departs from traditional analytical methodologies and utilizes a sequential Monte Carlo simulation to reproduce a random operating history of the failure/repair events of the system. Mathematical modeling is, therefore, unnecessary. This has the significant advantage of making possible the analysis of systems of considerable complexity. Switching sequences, complex operating procedures and the introduction of spare components can be modeled without difficulty.

II. EQUIPMENT OUTAGE DATA

Equipment forced outage data from published sources are shown in Table 1. When a data source provided outage data for more than one voltage class, the 230 kv data were selected as being typical of main grid switching substations. The data used in this study are shown in the last two columns of Table 1, with the selection based on size of equipment outage sample and with a preference given to higher failure and repair rates. Note that line data are given for 100-mile sections.

III. SUBSTATION SWITCHING CONFIGURATIONS

Simplified diagrams of the breaker configurations considered in this study are shown in Figure 1.

Each substation has six circuits connected. The breaker configurations are modeled as follows:

1. Single Bus. This configuration consists of one main bus that is energized at all times and to which all circuits are

	Ref 2		Ref 3		Ref 4		Ref 5		Ref 7		Ref 8		This Study	
	λ	μ	λ	μ	λ	μ	λ	μ	λ	μ	λ	μ	λ	μ
Line	0.25	20	1.00	10	-	-			0.93	28	-	-	1.0	10
Transformer	0.04	200	0.10	150	0.068	141	0.026	43	0.25	48	-	-	0.25	200
Breaker	0.18	160	0.02	12	0.044	105	0.002	126	-	-	0.12	132	0.18	160
Bus	0.09	6	0.025	25	-	-	0.025	13	-	-	-	-	0.09	6

Table 1 Equipment Outage Data

Notes

1. λ=failure rate (frequency/year), μ=repair rate (hours/outage)
2. For breakers the switching time of 1 hour is used in configurations where a breaker bypass facility is required, e.g. in the single bus configuration.

connected. Bus faults or failure of any circuit breaker to operate under fault conditions will result in the loss of the entire substation. Obviously this configuration has low reliability and should not be used with a six-circuit substation. It is included in this study to provide a benchmark for the results.

2. Sectionalized Bus. This is an extension of the single bus configuration, with two or more single bus schemes, each tied together with bus sectionalizing breakers, which may be operated normally open or closed depending on system requirements. A bus fault or breaker failure will cause the loss of only the affected bus section.

3. Main and Transfer Bus. This arrangement consists of two independent buses, one of which is normally energized. Isolation of any breaker for maintenance is accomplished with the use of a bypass switch around the breaker, and energization of the transfer bus through the closure of the bus tie breaker. Failure of a circuit breaker or a bus fault causes loss of the entire substation.

4. Ring Bus. In this arrangement a line or bus fault will cause the operation of the two adjacent breakers and the loss of the affected bus section. Only one circuit is lost. A line fault, combined with the failure of one breaker to operate, will result in the loss of two circuits. Any breaker can be isolated for service without loss of service to any of the circuits.

5. Breaker and a Half. This configuration consists of two main buses, each normally energized. Three circuit breakers are connected between the two buses and each circuit is connected between two breakers. Faults on either of the main buses do not cause circuit interruptions. A line fault, combined with the failure of one breaker to operate, will result in the loss of two circuits if a common breaker fails or one circuit if an outside breaker fails. Any breaker can be isolated for maintenance without interrupting any circuits.

6. Double Breaker Double Bus. This arrangement consists of two main buses, each normally energized. There are two breakers connected between the two buses and one circuit between the two breakers. Any breaker can be removed for maintenance without any circuit interruptions. Faults on either of the main buses cause no circuit interruptions.

Breaker failure results in the loss of only one circuit.

IV. SIMULATION RESULTS

This study uses a sequential Monte Carlo simulation to produce a random operating history of the failure/repair events of the system. Each system component is represented in the model by two probability distributions: one defined by its failure rate λ and another defined by its repair rate μ. The simulation starts at time=0 with all components in the UP state. Random numbers are then generated for each system component and each random number is related to a time-to-failure (TTF) for each component, according to the exponential probability distribution defined by the component's failure rate λ. The smallest TTF defines the component that fails first. A new set of random numbers is then drawn which will determine the next event. This may be the repair of the failed component or the failure of another component. The system capability is determined during each simulation interval by using an algorithm which relates the new topology of the substation and the

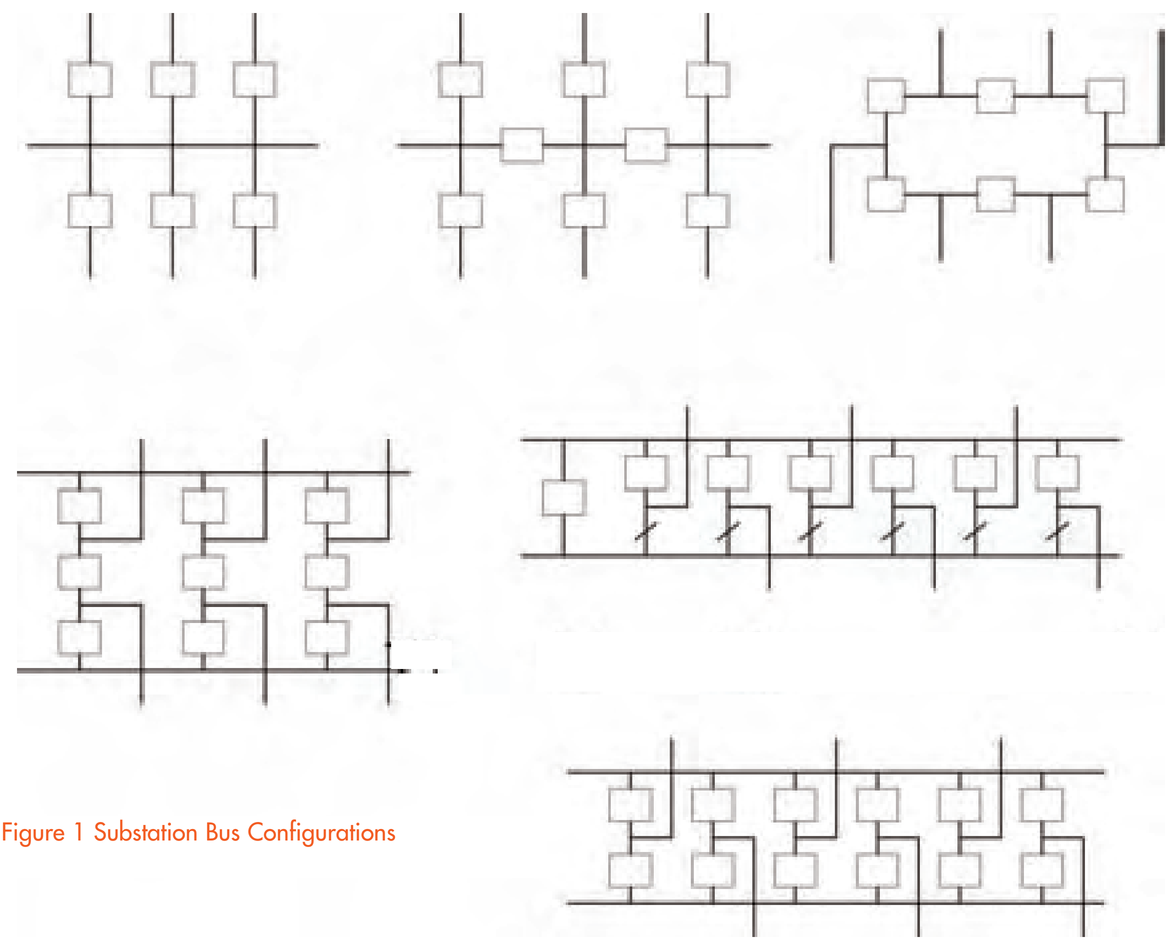


Figure 1 Substation Bus Configurations

status of all components to a transfer capability or a load serving capability.

The cumulative duration of each transfer capability state is computed and this allows the computation of the loss of load probabilities at the end of the simulation. This algorithm is based on certain base assumptions:

- two of the six circuits are 100-mile incoming lines (L1, L2).
- two of the six circuits are 100-mile outgoing lines (L3, L4).
- two of the six circuits are transformers feeding into a local substation (T1, T2).
- the electric power system is designed so that the loss of any of the two incoming lines does not result in loss of load (N-1 criterion). Loss of both incoming lines results in loss of 100% of the total substation load.
- The two outgoing lines serve area loads radially and loss of any of the two lines will result in loss of load equal to 25% of the total substation load.
- Loss of any of the two transformers will not result in loss of load. Loss of both transformers results in the loss of 50% of total substation load.

The simulation methodology does not depend on the preceding assumptions but the specific algorithm used in the simulation does. The methodology can accommodate any other assumptions and operating policies of considerable complexity. The results of the simulation are shown in Table 2.

The single bus configuration has very low reliability with 3.1 x 61 = 189 hours annually of load shedding. It shows a probability of 2% that the entire substation will be shut down. This translates to 175 hours annually of total shutdown. The provision of a bypass switch for each breaker increases the reliability of the single bus substation significantly for a modest cost increase of 7%, making this configuration less costly and more reliable than the sectionalized bus substation. The analysis shows that the ring bus configuration provides the best value for the six circuit substation. It has the same reliability as the double-breaker-double-bus configuration at 53% of the cost. The six-circuit ring bus is superior to the breaker and a half option as well, having the same reliability at 72% of the cost.

The results provided by the sequential Monte Carlo simulation method are expressed in terms of reliability indices of frequency and duration. These can be related to composite system reliability indices commonly used, such as the System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI). In a composite system reliability evaluation the entire substation can be modeled by its failure rate λ and its repair rate μ. For example, in a composite system study the ring bus can be modeled as a component having a failure rate λ=2 and a repair rate μ=10. The probabilities of the derated states 75%, 50% and 0 can be modeled by assigning corresponding portions of the probability distribution curve to the derated states.

V. CONCLUSIONS

Application of the sequential Monte Carlo simulation method in the reliability analysis of substation bus configurations can provide reliability indices such as the frequency of load shedding and the average duration of load shedding events, as well as the probabilities of derated states. In a composite system reliability evaluation these indices can be related to other commonly used system reliability indices, such as SAIFI and SAIDI. The method eliminates the need for Markovian modeling and is therefore suitable for the analysis of systems of considerable complexity.

REFERENCES

[1] R.N. Allan and J.R. Ochoa, “Modelling and Assessment of Station Originated Outages for Composite Systems Reliability Evaluation”, IEEE Transactions on Power Systems, Vol. 3, No. 1, February 1988, pp. 158-165.

[2] Xi-Fan Wang and Xiu-Li Wang, “Generalized Outage Table Approach to Reliability Study of Power Station Bus Schemes”, IEEE Transactions on Power Delivery, Vol. 12, No. 4, October 1997, pp. 1480-1485.

[3] J.J. Meeuwsen and W.L. Kling, “Substation Reliability Evaluation including Switching Actions with Redundant Components”, IEEE Transactions on Power Delivery, Vol. 12, No. 4, October 1997, pp. 1472-1479.

[4] D. Atanackovic, D.T. McGillis, F.D. Galiana, “Reliability Comparison of Substation Designs”, IEEE Transactions on Power Delivery, Vol. 14, No. 3, July 1999, pp. 903-910.

[5] R. Billinton and G. Lian, “Station reliability Evaluation Using a Monte Carlo Approach”, IEEE Transactions on Power Delivery, Vol. 8, No. 3, July 1993, pp. 1239-1245.

[6] US Dept. of Agriculture, RUS Bulletin 1724E-300, “Design Guide for Rural Substations”, June 2001.

Bus Configuration	Relative Cost From Ref [6]	Derates per year	Average Derate Duration (hrs)	Probabilities of Transfer Capacity States			
				100%	75%	50%	0
Single Bus	100%	3.1	61	0.977831	0.002207	0.000007	0.019954
Single Bus With Breaker Bypass	107%	3.1	7	0.997444	0.002340	0.000032	0.000184
Sectionalized Bus	122%	2.4	34	0.991759	0.008101	0.000099	0.000041
Ring Bus	114%	2.0	10	0.997687	0.002297	0.000012	0.000004
Main and Transfer Bus	143%	2.4	30	0.991062	0.008836	0.000031	0.000072
Main and Transfer Bus With Breaker Bypass	153%	2.4	9	0.997638	0.002280	0.000008	0.000075
Breaker and a Half	158%	2.0	10	0.997660	0.002251	0.000086	0.000002
Double Breaker Double Bus	214%	2.0	10	0.997695	0.002270	0.000034	0.000001

Table 2 Simulation Results

Transformer

Continued from Page 23

with time. A high rate of CO2 can result from cooling equipment malfunction (pump running backwards) or poor condition (coolers plugged with dirt or cottonwood tree fluff) however it's hard to assign a general number as to how high is too high. CO is also produced by normal aging but in much lesser amounts. Also, since solubility is much lower than CO2, CO is much more likely to disappear (like H2) rather than accumulate like CO2. This is highly dependent upon how tightly sealed a specific transformer is.

Figure 3 showed the CO2 and CO ppm rate-of-change (ROC) cycling up and down during the 30 day period prior to August 28th. This appears to be related to variations in oil temperature (mostly due to ambient & occasionally load) consistent with other on-line DGA experiences. Apparently, CO2 and CO dissolved in the oil are absorbed by the paper insulation as oil temperature decreases and returns to the oil as oil temperature increases.

This shows up dramatically through on-line DGA when old units are degassed (for whatever reason) that have accumulated large quantities of various gases. CO2 & CO show a pronounced ppm-decrease (being absorbed by the insulation) as the transformer cools after taken off line. CO2 & CO in the paper are not removed by the degassing process, as are other dissolved gases, and over a period of a month or two slowly return to the oil after the unit is back in service.

SETTABLE ROC LIMITS

Serveron on-line gas analyzers have provisions for user-settable ppm level plus ppm/day caution and alarm limits individually-settable for each gas in Serveron software for True Gas analyzers; settable in hardware for TM8 analyzers. [Figure 3 shows trending of ppm/day rate-of-change for individual gases viewable with Serveron Monitoring Service (SMS) software introduced in 2005]. As users gain experience & familiarity with on-line monitoring, they are beginning to implement ROC limits, as well as ppm limits, to take full advantage of on-line DGA.

CONCLUSIONS

The root cause of the gas generation in Dresden Unit 2 main power transformer is attributed to overheated crimped connections caused by a combination of high eddy losses in the crimps, poor oil circulation in the insulated high-current crimped bundled areas, and to a lesser extent by an uneven current distribution.

Why do more people buy FLIR infrared cameras than **all other brands combined?**

LOW COST!
INFRACAM™ SD

With InfraCAM SD's Removable Memory Card, You're No Longer Tethered to Your Computer!

Plus, you'll get razor-sharp thermal image quality, 1000 Radiometric JPEG Images with a Removable SD/Memory Card, an ultra-portable design and exceptional ergonomics. Weighs just 1.2 lbs, long 7-hour battery life!

Get More Done With InfraCAM SD!
Call for a Free Demo! 1-800-613-0507 Ext. 25

Training Value Package Available!
Visit: **www.goinfracam.com**

NEW! InfraCAM SD
Thermal Imager

Removable SD/Memory Card

NEW!
ThermaCAM® P640
Infrared Camera

HIGH DEFINITION
ThermaCAM® HD

The only High Definition infrared camera on the market today!

Superior image quality, spot size resolution, temperature measurement accuracy – the new standard for Professional Thermographers! Call 1-800-613-0507 Ext. 24

Training Value Package Available!
Visit: **www.highdefinitioninfrared.com**

FLIR SYSTEMS™
The Global Leader in Infrared Cameras
Servicing Canada for 46 years

1-800-613-0507 | Ext. 25 for **InfraCAM SD**
Ext. 24 for **P640 HD**

IRCanada@flir.com www.flir.ca