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Maintaining the Grid:

- **MAXIMIZING RELIABILITY ON THE AUSTRALIAN GRID**
- **MANAGING ENERGY TRANSACTIONS ACROSS THE KINGDOM OF JORDAN**
- **CAN NEGAWATTS COMPETE WITH MEGAWATTS?**

and

- **TRANSFORMER MAINTENANCE INTERVAL MANAGEMENT**
- **LEVERAGE RISK/DEMAND WITH OUTSOURCED IT SECURITY**

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MAXIMIZING RELIABILITY ON THE AUSTRALIAN GRID

By Anthony Tisot

As Victoria's largest electricity distributor, Powercor Australia devotes considerable energy to maintaining and developing the quality and reliability of the power it delivers to its customers. Although not an electricity retailer, they own and operate the distribution network that delivers electricity across 76,000 km of circuits to more than 600,000 premises throughout Western Victoria, from Melbourne's western suburbs to the borders of South Australia and New South Wales. Since its start in 1996, the company has experienced considerable growth and continues to add more than 10,000 new connections to its distribution network each year. To guarantee its customers a reliable source of quality power, Powercor Australia invests $100 million AUD each year on maintenance and development and, since 2000, has invested almost $10 million more in its distribution network.

Recently, they embarked upon a major endeavor to upgrade 55 zone substations, plus several strategic customer-related installations, with a network of intelligent energy meters and software. The goal of this upgrade was to provide Powercor engineers with the tools to remotely monitor and control conditions at each zone substation, and to help optimize power quality and reliability across an entire distribution network spanning more than 74,000 distribution substations.

A COMMITMENT TO QUALITY

According to Joe Thomas, network planning manager for Powercor Australia, the decision to upgrade the company's distribution network was motivated by several factors, not the least of which was an industry regulator's requirement to report any voltage fluctuations occurring at the 22kV supply points of each zone substation. To align with annual network performance targets set by Victoria's Essential Services Commission, Powercor maintains "Guaranteed Service Levels" as a commitment to provide its customers with a consistent level of reliable, high-quality service.

To help ensure a safe, reliable and high-quality electricity supply, the company's Network Planning group identified a need for remote access to detailed energy-metering data from each zone substation, plus the tools to help pinpoint potentially damaging conditions such as excessive harmonic frequencies, sags and swells, transients, and phase unbalance. "Aside from a few protection relays, the zone substations originally offered very basic equipment for metering, and no capacity for monitoring

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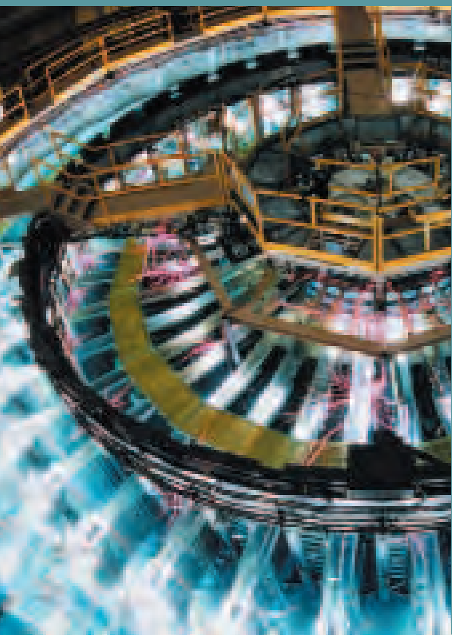

AUSTRALIAN GRID

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power-quality conditions such as transients or sags and swells," explains Thomas. "We knew that a more comprehensive system for monitoring energy would provide our Network Planning group with the type of detailed metering data necessary to make informed system-augmentation decisions."

According to Thomas, the Network Planning group also needed a way to gather accurate consumption data to better assess customer usage patterns, and proactively prepare for periods of increased power consumption. "Although energy consumption is high throughout Australia's winter months (June through August), demand increases significantly in the summer (December through February) mainly due to the increased use of cooling equipment such as air conditioning and cooling storage units," says Thomas. "We knew that creating a profile of energy consumption across the entire distribution network, and using this information for trending system quantities on an ongoing basis,would be invaluable for supporting decision making."

MANAGING ENERGY, ENTERPRISE WIDE

To meet these requirements, Powercor installed an ION® enterprise energy management ("EEM") system from Power Measurement. With the assistance of Eltec Energy Services, Power Measurement's regional representative, Powercor equipped its zone substations with ION 7600 or ION 7700 intelligent energy meters, and connected the meters to a centrally located computer workstation running ION Enterprise® energy management software. Each energy meter was then configured to collect detailed power quality and energy data at the source, and provide it to the ION Enterprise software server located at Powercor's head office. Once the EEM system was brought online, the software could automatically monitor each meter in the network, analyze the data, and notify personnel of any threats to power quality or reliability.

Because of the remote locations and considerable distances involved, each meter was equipped with an expanded onboard memory to accommodate additional data in the event of a communications interruption. Although the meters currently communicate with the head-end software via modem, Powercor is in the process of upgrading its communications network to Ethernet over fiber for improved speed and reliability.

At each zone substation, the ION meters measure electricity delivered to

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TRANSFORMER MAINTENANCE INTERVAL MANAGEMENT

By Roy Moxley and Armando Guzman, Schweitzer Engineering Laboratories, Inc.

ABSTRACT

Recent surveys indicate that the average age of utility power transformers exceeds 30 years. Managing these critical assets requires monitoring the factors that cause transformer damage. Excessive heat and mechanical stress during through faults on transformers are recognized as the two major causes of damage. New technology in transformer protection relays provides for both thermal and through-fault monitoring.

This paper demonstrates how to use the transformer thermal damage and loss-of-life information from IEEE Std. C57.91-1995 to schedule proactive maintenance. It also presents through-fault recording and accumulated data and discusses how these relate to transformer short-circuit standards.

INTRODUCTION

In the historical struggle between ac and dc power transmission, ac is generally preferred because it allows easy conversion of voltages to higher levels for long distance transport. Power transformers are a critical link in the ac path of electricity from the generating stations to end users. In terms of total investment, electric utilities invest at least as much in transformers as they do in generating stations. In many cases, because of the larger installed base, utilities invest more in transformers.

Transformers are expected to last from 20–30 years, and in many cases, even longer. Because regulators and financial markets measure a utility's ability to make efficient use of resources, utilities must maximize asset utilization. Based on transformer design and experience, we know that the amount of service a transformer "sees" is an indicator of serviceability. As they say, "it's not the age — it's the mileage."

Measurable indicators of transformer serviceability include electrical load; top-oil, hottest-spot, and ambient temperatures; fault history; and dissolved gas analysis. Utilities that use these indicators can make intelligent profit/risk decisions and plan optimal transformer loading and maintenance.

MEASUREMENTS

The best way to protect and extend the life of transformers is to collect information such as load and fault current as well as top-oil or hottest-spot temperatures, and receive notification when a value has reached a preset level. Logically combining these quantities can help predict or anticipate an alarm condition, and keeping a record of these measurements provides a more complete picture of the transformer's insulation condition.

The challenge is providing a means to collect this information without creating a massive new system requiring its own maintenance and cost structure. Protective relays that are permanently connected to the transformer current (and possibly temperature inputs) as shown in Figure 1, have memory and recording

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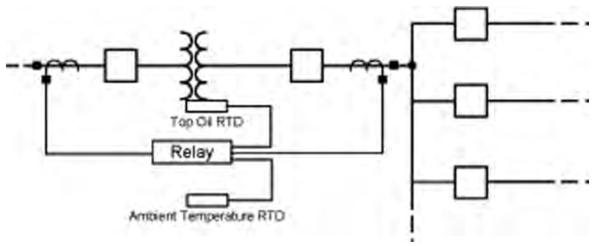

Figure 1 Transformer Relay With Connected RTDs for Thermal Monitoring

capability and logical decision making capacity, can be the beginning of a comprehensive "life management" system for transformers.

Construction and usage standards for transformers provide a starting point for applying these measurements to determine optimal loading at a given ambient temperature and predict when it is appropriate to schedule maintenance prior to a life-ending event.

TEMPERATURE MEASUREMENTS AND CALCULATIONS

IEEE standards and numerous technical papers have established guidelines for loading transformers based on temperature limits for oil and conductors. For example, recognizing that a "loss of life" occurs as temperatures increase, IEEE Standard C57.115-1991: Guide for Loading Mineral-Oil-Immersed Power Transformers Rated in Excess of 100 MVA (65ºC Winding Rise), Table 2, includes temperature limits for different load conditions. All of the conditions above normal loading involve some degree of an accelerated loss of life of the transformer [1] [2].

The standard shows that from a managed ownership standpoint, regularly overloading a transformer at high ambient temperatures causes accelerated aging. The question is: how should maintenance of the transformer change based on the amount and duration of overloads?

Both operator actions and system events can cause transformer overloads. Therefore, temperatures should be continuously monitored, and accumulated loss of life should be measured and recorded. The most important two values to calculate or measure are hottest-spot temperature and top-oil temperature. IEEE Std. C57.91-1995 provides formulas for performing these calculations. We have programmed these formulas in protective relays to calculate temperatures. The user inputs the transformer constants required (see Appendix A), such as thermal time constants, ratio of no-load to load losses, and total losses at rated output. If these constants are unknown, the standards provide reasonable default values for approximate calculations.

Using the entered constants, the relay provides instantaneous and accumulated loss-of-life and aging acceleration factor alarm points. Calculations are based on what information is available. Temperature devices on the transformers, such as Resistance Temperature Detectors (RTDs), may or may not be available, so different calculations are made depending on this availability [3].

THERMAL CALCULATIONS USING AMBIENT AND TOP-OIL TEMPERATURES

In this case, the relay receives measured ambient and top-oil temperature inputs and uses the top oil temperature to calculate the hottest-spot temperature.

A single-tank, three-phase transformer can have as many as two thermal inputs: the ambient temperature input and the top-oil temperature input. Independent, single-phase transformers normally have as many as four thermal inputs: an ambient temperature input and a top-oil temperature input for each one of the three tanks. During a fixed time interval, Δt = 1 minute, the relay calculates the winding hottest-spot temperature at the end of the interval, according to the following expression:

$$\Theta_H = \Theta_{TO} + \Delta\Theta_H$$

where:
Θ_H = winding hottest-spot temperature, °C
Θ_{TO} = top-oil temperature, °C
$\Delta\Theta_H$ = winding hottest-spot rise over top-oil temperature, °C

The relay calculates winding hottest-spot rise over top-oil temperature, $\Delta\Theta_H$, according to the following:

$$\Delta\Theta_H = \left(\Delta\Theta_{H,U} - \Delta\Theta_{H,i}\right) \bullet \left(1 - e^{\frac{-\Delta t}{60 \bullet \tau w}}\right) + \Delta\Theta_{H,i}$$

where:

$\Delta\Theta_{H,U}$ = the ultimate hottest-spot rise over top-oil temperature for any load, °C
$\Delta\Theta_{H,i}$ = initial hottest-spot rise over top-oil temperature at the start time of the interval, °C
τ_W = winding time constant of hot spot, in hours
Δt = one-minute temperature data acquisition interval
$\Delta\Theta_{H,U} = \Delta\Theta_{H,R}K^{2m}$

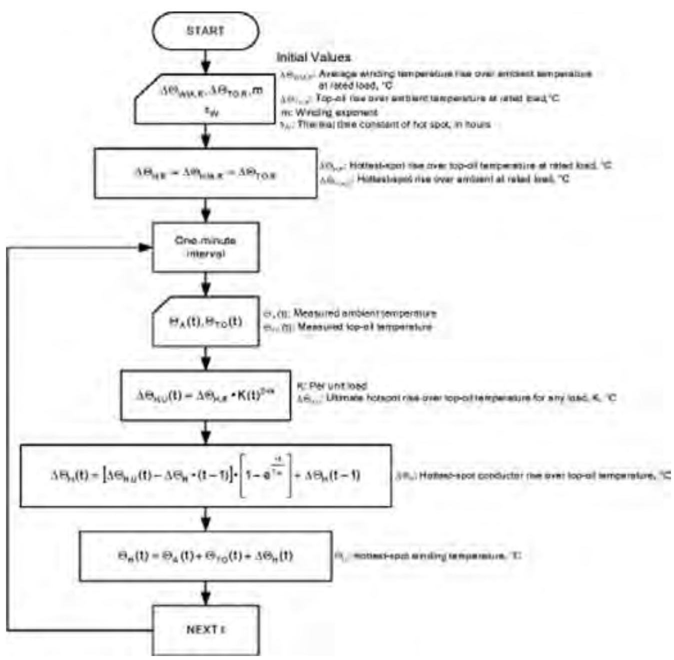

Figure 2 Iterative Real-Time Hottest-Spot Calculation

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where:

K = load expressed in per unit of transformer nameplate rating according to the cooling system in service (phase current divided by the nominal current)

m = winding exponent

$\Delta\Theta_{H,R}$ = rated winding hottest-spot rise over top-oil at rated load, °C

The implementation of this equation over time is shown in Figure 2.

THERMAL CALCULATIONS WITH ONLY AMBIENT TEMPERATURE INPUTS

If only ambient temperature is available, the relay calculates both top-oil temperature and hottest spot temperature. Typical variances in ambient temperature for the same load could result in a difference in aging of transformer insulation by 100 times, so it is critical that ambient temperature is available.

Where the relay has a measured ambient temperature input without a top-oil temperature input, you have one thermal input (for ambient temperature) regardless of whether you have a single three-phase transformer or independent single-phase transformers. The relay calculates winding hottest-spot temperature, Θ_H, according to the equation in the earlier case:

$$\Theta_H = \Theta_{TO} + \Delta\Theta_H$$

and calculates top-oil temperature, Θ_{TO}, according to the following:

$$\Theta_{TO} = \Theta_A + \Delta\Theta_{TO}$$

where:

Θ_A = ambient temperature, °C

$\Delta\Theta_{TO}$ = top-oil rise over ambient temperature, °C

The relay calculates top-oil rise over ambient temperature according to the following:

$$\Delta\Theta_{TO} = (\Delta\Theta_{TO,U} - \Delta\Theta_{TO,i}) \cdot \left(1 - e^{\frac{-\Delta t}{60 \cdot \tau_{TO}}}\right) + \Delta\Theta_{TO,i}$$

where:

$\Delta\Theta_{TO,U}$ = the ultimate top-oil rise over ambient temperature for any load, °C, and is a function of load

$\Delta\Theta_{TO,i}$ = initial top-oil rise over ambient temperature at the start time of the interval, °C

τ_{TO} = top-oil time constant of transformer, in hours

The relay calculates the ultimate top-oil rise over ambient temperature, $\Delta\Theta_{TO,U}$, according to the following expression:

$$\Delta\Theta_{TO,U} = \left(\frac{K^2 \cdot R + 1}{R+1}\right)^n \cdot \Delta\Theta_{TO,R}$$

where:

R = ratio of load loss at rated load to no-load loss

n = oil exponent

$\Delta\Theta_{TO,R}$ = top-oil rise over ambient temperature at rated load, °C

For any n (oil exponent) value and any load value, the relay calculates the thermal top-oil time constant according to the following expression:

$$\tau_{TO} = \tau_{TO,R} \cdot \left[\frac{\frac{\Delta\Theta_{TO,U}}{\Delta\Theta_{TO,R}} - \frac{\Delta\Theta_{TO,i}}{\Delta\Theta_{TO,R}}}{\left(\frac{\Delta\Theta_{TO,U}}{\Delta\Theta_{TO,R}}\right)^{\frac{1}{n}} - \left(\frac{\Delta\Theta_{TO,i}}{\Delta\Theta_{TO,R}}\right)^{\frac{1}{n}}}\right]$$

where:

$\tau_{TO,R}$ = thermal time constant in hours at rated load with initial top-oil temperature equal to ambient temperature

Real-time values include calculated temperatures as well as loss-of-life accumulations.

Instantaneous values are useful to operators in making dispatch decisions.

Transformer standards provide guidelines for operating at “damaging” thermal levels. For example, Table 1 from IEEE Std. C57.115-1991 provides what can be considered reasonable loading times for given hottest-spot temperatures [1]. Operators or relays should act to limit the time at higher-than-rated temperatures. Relay contacts or alarms sent via SCADA can also initiate control actions to reduce load.

INSULATION AGING

Hottest-spot temperature above 90–105ºC causes irreversible degradation of the cellulose insulation structure of a transformer [4] [5]. This degradation accumulates over time until the insulation material fails. The mode of the insulation failure in these cases is typically of a mechanical nature, e.g., cracking and flaking caused by the heavy carbonization of the insulation material. This mechanical degradation of the insulation material eventually results in an electrical failure of the device.

Insulation Aging Acceleration Factor

Based on transformer standards, we calculate an insulation aging acceleration factor, F_{AA}, which indicates how fast the transformer insulation is aging.

We calculate the insulation aging acceleration factor, F_{AA}, for each time interval, Δt, as follows:

$$F_{AA} = e^{\left[\frac{B}{(\Theta_{H,R}+273)} - \frac{B}{(\Theta_H+273)}\right]}$$

where:

F_{AA} = insulation aging acceleration factor

B = is a design constant, typically 15000, °C

$\Theta_{H,R}$ = winding hottest-spot temperature at rated load (95°C if $\Delta\Theta_{W/A,R}$ = 55°C, 110°C if $\Delta\Theta_{W/A,R}$ = 65°C)

$\Delta\Theta_{W/A,R}$ = average winding rise over ambient at rated load (setting)

Daily Rate of Loss of Life

Now we calculate daily rate of loss of life (RLOL, percent loss of life per day) for a 24-hour period as follows:

$$RLOL = \frac{F_{EQA} \cdot 24}{ILIFE} \cdot 100$$

where:

RLOL = rate of loss of life in percent per day

ILIFE = expected normal insulation life in hours

To provide the user with trend information on the loss of insulation, the RLOL value should be automatically recorded.

The equivalent life at the reference hottest-spot temperature (95ºC or 110ºC) that will be consumed in a given time period for a given temperature cycle is:

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA_n} \bullet \Delta t_n}{\sum_{n=1}^{N} \Delta t_n}$$

F_{EQA} = equivalent insulation aging factor for a total time period
n = index of the time interval, Δt
N = total number of time intervals for the time period
F_{AAn} = insulation aging acceleration factor for the time interval, Δtn
Δt = time interval
During 24 hours, the total number of time intervals is:

$$N = \frac{24}{\left(\frac{\Delta t}{60}\right)} = \frac{1440}{\Delta t}$$

where:
Δt = time interval
Because the time intervals and the total time period used in the thermal model will be constant, we can simplify the calculation of FEQA to the following:

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA_n}}{N} = \text{(equivalent life in days)}$$

Total Accumulated Loss of Life

An estimate of the total accumulated loss-of-insulation life in percentage of normal insulation life can be made by summing all of the daily RLOL values:

$TLOL_d = RLOL_d + TLOL_{d-1}$

where:
$TLOL_d$ = total accumulated loss of life, TLOL
$RLOL_d$ = most recent daily calculation
$TLOL_{d-1}$ = previous TLOL

Damage, or aging of insulation, roughly doubles with every 6–8ºC of temperature above 90ºC [5]. We can plot the approximate effects of hottest-spot temperature on insulation aging as shown in Figure 3.

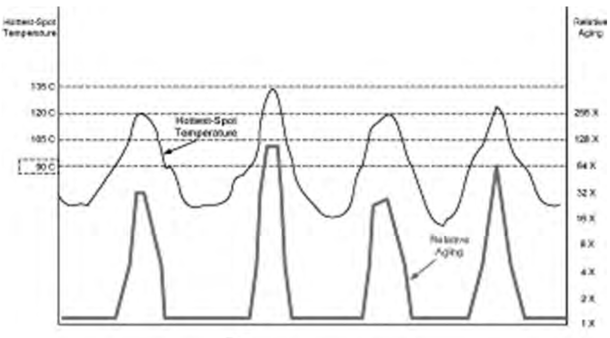

Figure 3 Relative Aging vs. Hottest-Spot Temperature

Accumulated loss of life provides an indicator of the impact of operational overloads on the transformer. Simply, it is the integral over time of the accumulated aging, taking into account the effect of accelerated aging caused by elevated temperatures.

Moisture content in the cellulose insulation has a significant impact on insulation aging [4] [6]. If the moisture content increases from 0.5% to 1.0%, the rate of aging of the cellulose insulation at least doubles for a given temperature. Moisture in the insulation can be estimated by applying an appropriate algorithm [7] to the measured water content in the oil. Because it is important to know the amount of water in the transformer oil, even an advanced temperature monitoring system cannot completely predict the perfect time to perform maintenance. Using the calculated moisture content to adjust the thermal aging of the insulation improves the ability to predict maintenance.

COMPARING CALCULATED AND MEASURED VALUES

While it is advantageous to have top-oil and hottest-spot temperatures available from direct measurements, calculated values are also useful. Obviously, for a transformer without top-oil or hottest-spot RTDs, a calculated value is the only one possible. The calculated values for top-oil and hottest-spot temperatures can be derived using load currents and either measured or fixed (manually entered setpoint) values for ambient temperature. When based on assumed ambient tem-

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peratures, the calculated values will be very unreliable.

If measured oil temperatures are available, then it is possible to compare the calculated values with the measured values. This gives an indication of the effectiveness of the cooling system. An alarm can be issued if the difference between measured and calculated temperatures exceeds a preset value. Failed pumps, birds nests in the fans, or any number of other problems can be detected and corrected this way, before they cause a catastrophic transformer failure. Comparing calculated and measured values can also be used to correct setting constants.

THROUGH-FAULT MONITORING AND ALARMS

According to insurance industry studies [8], through faults are the number one cause of transformer failure today. Initiation of a through fault can be seen in Figure 4 below.

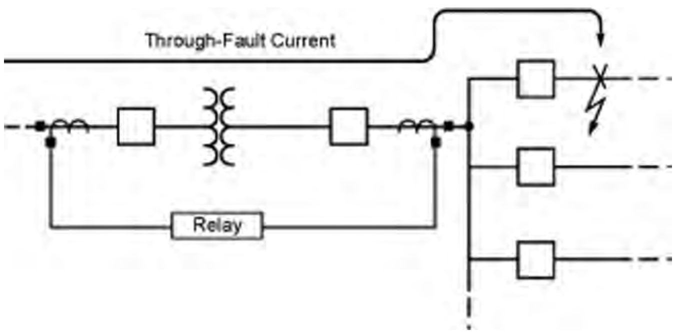

Figure 4 One-Line Diagram of a Typical Through-Fault Event

As fault duty and feeder exposure increase, the incidence and severity of through faults experienced by a transformer will tend to go up over time. IEEE Std. C57.12 [9] provides construction guidelines for short-circuit withstand for transformers. The standard states that a transformer shall withstand 2 seconds of a bolted fault at the transformer terminals. Testing to verify through-fault withstand capability is normally performed on a design basis, with the length of the test limited to 0.5 seconds for up to 30 MVA three-phase transformers.

When evaluating how to assess possible damage or loss of life to an installed transformer subjected to a through fault, it is interesting to consider testing standards and their implications. The test standards are “intended for use as a basis for performance [10]”. Test standards are established only for new units, to some degree in recognition that normal service life of a transformer will cause it to have an unpredictable response to short-circuit tests; yet those tests are a simulation of what the transformer may experience with the next through fault.

Following short-circuit tests, a careful set of visual and electrical tests is performed to verify there has been no, or minimal, movement of the coils as a result of the forces incident to a short circuit. In an installed transformer, it is generally not practical to perform even minimal visual and electrical tests following every through fault. So the question is: what is a reasonable expectation of length of life of a transformer, built to accepted standards, following normal through faults that every system will experience?

Plotting a comparison of the stresses a transformer experiences and its withstand capability against time could produce a graph such as Figure 5 [6].

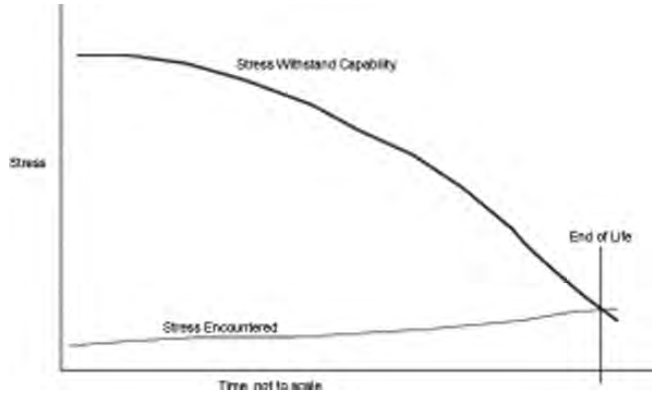

Figure 5 Stress Withstand Capability Over Transformer’s Lifetime

The stress withstand capability of a transformer is reduced gradually by degradation caused by overheating of the insulation components. The stresses the transformer are subjected to may increase over time due to increasing loads and an increase in short-circuit duty from additional system interconnections and sources.

If we were to modify Figure 5 to include more detail, also shown by Reference [6], we could create a graph such as Figure 6.

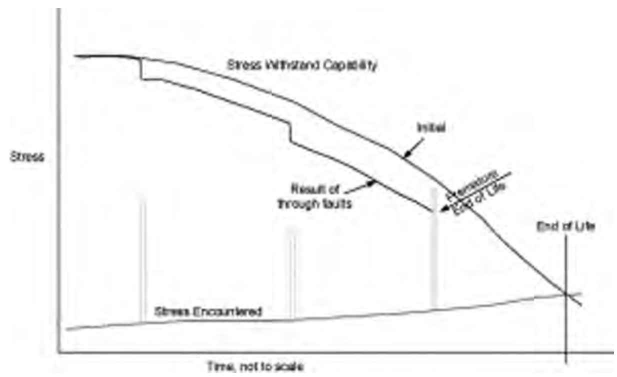

Figure 6 Stress Withstand Capability Over Transformer’s Reduced Lifetime

In this case, the transformer experiences three severe through faults. The first two faults reduce the transformer’s withstand capability to the point where it cannot withstand the forces of the third fault.

While not explicitly stated in IEEE standards (see [9]) this degradation in capability is predicted by the following equation [11]:

I2t = k (1)

where:

k generally equals a constant where t equals 2 seconds and I equals maximum fault current in per unit times normal base current. This matches the construction characteristics defined in IEEE Std. C57.12.

For example, for a transformer rated 40 MVA base rating, 230/69 kV and a 4% impedance connected to an infinite bus, we would have:

Base load current = $\frac{40}{3 \cdot 69} = 0.335$ kA

Equation 1 with maximum fault current then becomes:

$$\left(\frac{40}{3 \cdot 69 \cdot 0.04}\right)^2 \cdot 2 \text{ sec } 140 \text{ kA}^2 \text{ sec}$$

While this curve as presented in the IEEE standards [9] [11] is used for setting and coordinating protective devices for transformers, it can have practical applications to ongoing transformer service. In IEEE Std. C57.12, the transformer is constructed to be able to withstand this fault. This fault is the limit of what the transformer was designed to withstand; the testing standard provides for a design test of the transformer, when new, at a short-circuit duration of 1/4 of this time. Following the short-circuit test, the transformer is untanked and inspected visually for winding displacement or other damage. Electrical tests are performed to ensure insulation integrity and verify that parameters such as excitation current and impedance have not changed.

Users can measure and record the fault duty seen by a transformer on the same basis as the design tests performed in the factory. This gives the user a basis for evaluating the service life remaining in the transformer before inspection and testing are required.

COMBINED MEASUREMENTS

Temperature loss-of-life calculations are based on a gradual and continual aging process similar to that shown in Figure 5. While sudden and severe overloading at high ambient temperature could cause a temporary increase in the aging "slope," as long as the overload is not so severe as to burn up the transformer, the process is akin to sliding down a hill and not falling off a cliff.

On the other hand, a through fault is a sudden and severe event by its very nature. As shown in Figure 6, the mechanical forces incident to the through fault can cause an insulation structure that is already aged by years of loading to fail.

The problem is that overloading guidelines do not take into account the short-circuit stresses that a transformer may have or may yet experience. Likewise, short-circuit design and testing standards are made for new units that have not experienced any aging of the insulation structure. The advantage of having one device perform both the thermal recording and loss-of-life calculation, as well as the through-fault monitoring and accumulated fault duty recording, is that now these two factors can be combined for an effective maintenance indicator.

For example, if we define TLOLL = Total Loss-of-Life Limit and ISQT = Accumulated I2t of fault duty, we can write a logic equation to initiate alarm for a transformer similar to that in the through-fault monitoring example:

Alarm = (TLOLL > 70%) AND (ISQT > 98 kA^2 seconds)

This alarm can be a sign that because the transformer has an accumulated thermal loss of life of 70% as well as an accumulated through-fault duty of 70% of its nominal withstand capability, it is time for at least a thorough inspection and possibly an overhaul to reblock or even rewind.

A possibly greater application is to use the outputs from the monitoring associated with electrical quantities with other transformer information that may be available. These other monitoring devices or methods can include sudden pressure relays, thermal imaging, and dissolved gas analysis.

Sudden pressure relays have been reported to have occasional problems with misoperation on external faults. For this reason, they are sometimes used for alarm only and not tripping [12]. An alarm from a sudden pressure relay may have more consequence as a maintenance predictor if coupled with an accumulated loss of life due to overload. Within a digital relay, it is a simple matter to either logically or electrically combine the output of the sudden pressure relay with the accumulated loss-of-life alarm. This allows recognition of degradation in insulation, making small movements of the core and coil assembly more significant, and possibly, events worthy of initiating an inspection.

Thermal imaging can be used to compare calculated top-oil temperatures with measured values, as suggested in the thermal monitoring section above. Cooling effectiveness, or the lack thereof, can then be evaluated prior to damage.

Dissolved gas analysis is more suited to be an interim step between an accumulation of events and a complete inspection than as a frequent diagnostic action, except on the largest transformers.

TURNING DATA INTO INFORMATION

It is not enough that data on overall loss of life exist inside a relay. It must be transmitted to a person who can use the information to improve decision-making and better manage the transformer asset. The simplest way to send data is to assign an alarm contact to a certain loss-of-life level. The

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problem is that this takes away the additional intelligence that may be available, as discussed in previous sections. Using a communications processor to send a complete report to a responsible engineer is a way to send more useful information (Figure 7).

With more complete information, the engineer can assess the degree of risk associated with continuing with the transformer in service under the same conditions or performing maintenance. Combining multiple reports — such as thermal, through-fault, and online dissolved gas analysis — can give the best view of the conditions within the transformer.

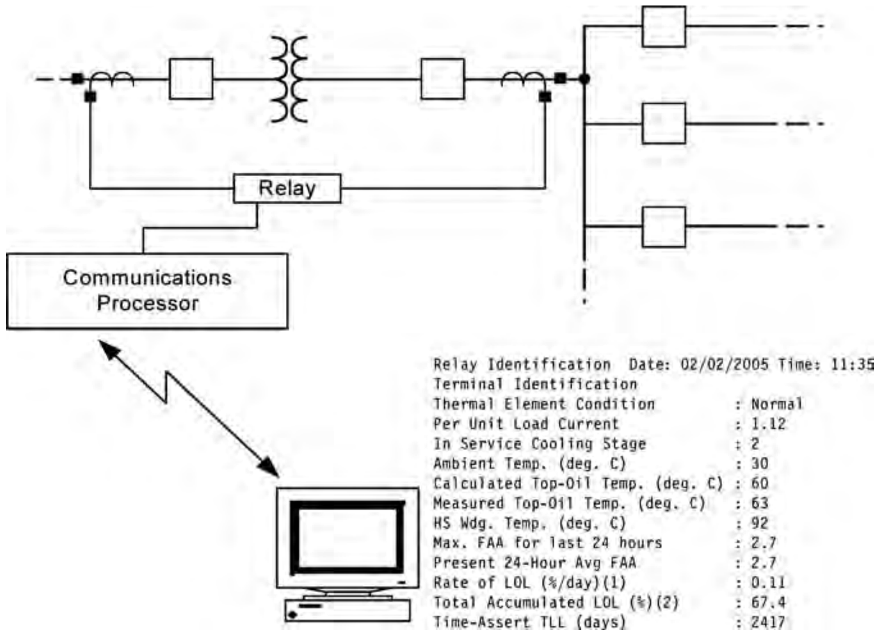

Figure 7 Using a Communications Processor to Send a Formatted Report

CONCLUSIONS

While using the alarm point as a maintenance indicator may sound like additional work, doing so can actually prevent maintenance work. If a unit has not experienced an accumulated life duty to indicate that maintenance is necessary, then without some other indicator, maintenance is not necessary.

Transformers need to be utilized to their maximum capabilities, which mandates that maintenance actions and operating procedures take the consequences of maximum usage into account. Utilities that use all of the information available can postpone maintenance on units that have not seen excessive stress and accelerate maintenance schedules for units that have seen possibly damaging stress.

As transformer design tools improve, they not only provide for designs that are more assured of meeting standards, but they also allow transformer designers to avoid safety margins that may have existed in prior designs. This makes it more important to recognize what these design standards provide and how to measure when the limits defined by standards are approached.

1. A comprehensive transformer management plan continuously monitors and records thermal loading.

2. Comparing measured top-oil temperatures with calculated top-oil temperature provides a measure of cooling effectiveness that can be used to notify maintenance personnel of problems with fans or pumps.

3. Accumulated through-fault monitoring can be an indicator of necessary maintenance, just as accumulated thermal loading can.

4. Combining through-fault, temperature, and other factors can optimize maintenance practices for an overall reduction in total ownership costs.

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BIOGRAPHIES

Roy Moxley has a B.S. in Electrical Engineering from the University of Colorado. He joined Schweitzer Engineering Laboratories in 2000 as market manager for transmission system products. He is now a senior product manager.

Armando Guzmán (M '95, SM '01) received his BSEE with honors from Guadalajara Autonomous University (UAG), Mexico, in 1979. Since 1993 he has been with Schweitzer Engineering Laboratories in Pullman, Washington, where he is presently a Fellow Research Engineer.

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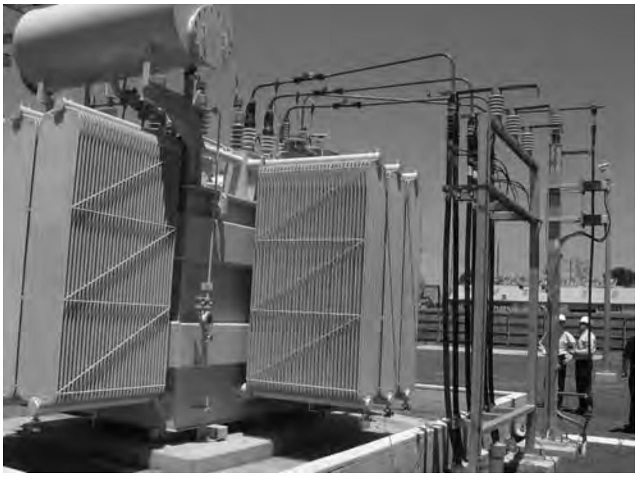

the substation at 66kV, and leaving the substation at 22kV. Additionally, they monitor power quality parameters such as sags and swells, transients, harmonics, flicker, voltage unbalance and current unbalance. To monitor consumption across the entire distribution network, the system automatically records total kWh as interval data logs, and presents this information as monthly reports. In the near future, the company plans to install additional meters at the terminal stations that supply power to the Powercor network.

CONTROLLING POWER QUALITY AND RELIABILITY

The end result is an enterprise-wide energy management system that provides real-time power monitoring and control capability across the entire distribution network. With 24-hour access to each zone substation, energy managers can now review real-time conditions and logged system data from multiple metering points to help determine effective maintenance strategies, or assess potential trouble spots. The system can also deliver alarm notifications to alert staff of any conditions requiring an immediate response. For example, the ability to trend harmonics is considered to be a key benefit of the system. If left unchecked, harmonics can cause severe damage to electrical equipment, overheating transformers, conductors, capacitors, and motors. “Due to the many new and varied technologies used by our customers, harmonics are an ever-increasing challenge,” confirms Thomas. “But with our improved power-quality monitoring capabilities, we can quickly identify potential trouble spots and take corrective action before reliability can be affected.”

The ability to remotely identify potential trouble spots has also helped Powercor improve reliability through enhanced awareness, increased efficiency, and reduced response time. Although Powercor employs comprehensive mitigation strategies to help minimize supply interruptions caused by bushfires, pole fires and wildlife, occasional damage or disruption along a line may occur, resulting in potentially damaging variations in voltage levels. By pinpointing the source of a problem and alerting staff, Powercor’s energy management network can help maintenance crews respond quickly and efficiently to minimize damage and correct any threats to reliability.

Powercor recently used its enhanced metering capability to monitor the effect of a hot water peak load which existed on a very weak network. “Our data illustrated how the distribution system tended towards voltage instability,” explains Thomas. “Using the system, we identified voltage regulators that were unable to coordinate or respond fast enough, and were able to quickly address the situation.” Although Powercor’s Network Planning engineers are among the EEM system’s primary users, the detailed energy information it provides has also proven useful to protection engineers, operations engineers, and regional managers throughout the organization. Additionally, the meters’ high sampling rate supports an increased level of power quality analysis that helps staff identify geographical areas that may be more susceptible to transient events. This capability also allows Powercor’s network planning team to view actual network voltages as a result of changing system conditions, and to develop a profile for each zone substation supply point. With this combined information on transients, sags and swells, personnel can better understand plant capability requirements across each segment of the network.

By upgrading its zone substations with advanced power monitoring and control technology, Powercor Australia now has the tools to track energy consumption, analyze power-quality conditions, and maximize reliability throughout its extensive distribution network. This initiative is just the latest in a series of strategies and programs that guarantee Powercor Australia customers a safe, reliable and affordable supply of high-quality electricity.

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MANAGING ENERGY TRANSACTIONS ACROSS THE KINGDOM OF JORDAN

Whether producing and delivering power in North America or around the world, many utilities are finding the key to staying profitable in today's competitive energy market is the ability to acquire and process information faster and more efficiently than ever before.

This is especially true in deregulated markets, where the success of independent generation, transmission and distribution companies hinges upon the timely and reliable exchange of accurate transaction and billing data between partners. In the Middle East, where the Hashemite Kingdom of Jordan is upgrading and restructuring the country's electricity transmission grid, Jordan's National Electric Power Company has constructed a synchronized, countrywide enterprise energy management network to provide energy companies with independent access to metering data from shared inter-tie points across the grid.

This advanced energy monitoring and communications infrastructure is expected to play a key role in helping to support business processes between market participants, while providing the tools to maintain a secure and reliable source of affordable energy for the country's five million residents.

CREATING A SUSTAINABLE ENERGY SECTOR

Located in the heart of the Middle East, the Hashemite Kingdom of Jordan is a country in the midst of some very big changes. Limited access to natural resources such as water and oil have traditionally placed significant constraints on the region, but for decades Jordan has faced these challenges with a steady commitment to increasing growth and improving living standards.

This initiative has grown into a countrywide goal to upgrade, and most recently, deregulate the region's electricity transmission grid. To accomplish this significant undertaking, the government of Jordan recently split the state-owned National Electric Power Company (NEPCO) into three distinct organizations, and embarked on the next challenge: building a countrywide energy-information infrastructure to monitor energy transactions and billing between the newly independent power generation, transmission and distribution companies.

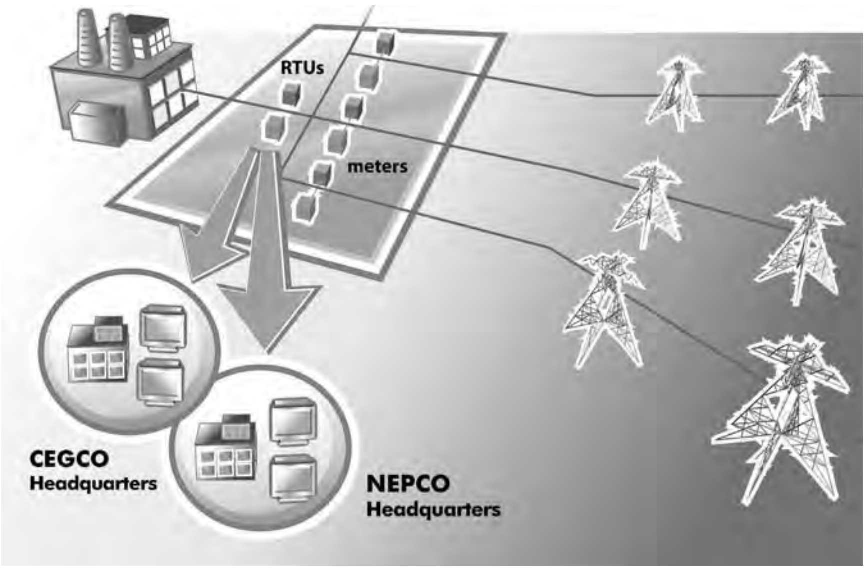
This represents a critical step towards Jordan's goal of creating a sustainable energy sector, characterized by efficiency, quality and growth.

JORDAN'S COMMITMENT TO QUALITY

The promise to improve Jordan's energy infrastructure dates back to 1967, when the government established the Jordan Electricity Authority (JEA). The JEA was entrusted with developing a system of modern power plants and a reliable high-voltage network that would deliver electricity to every village and rural community in the country. Once established, the JEA saw Jordan's installed capacity grow steadily to meet demand and provide sufficient reserve. By the early 1990s, nearly 100% of Jordan's population was supplied with electricity.

By this time however, falling oil prices had presented a new challenge to the national economy by reducing Jordan's levels of trade with oil-producing Arab countries. Faced with a faltering economy, Jordan looked for new ways to spur growth. In 1992, the country introduced an aggressive reform program intended to promote economic growth through the development of a market-based system.

For the power sector, this meant increasing the involvement of private concerns to help create a sustainable business and regulatory environment that would encourage investment and competition. In 1996, JEA was recast as the National Electric Power Company (NEPCO), a publicly held government entity. Then in 1999, the Cabinet split the state-owned NEPCO into three legally and financially independent operating companies: the Central Electricity Generation Company (CEGCO), the National Electric Power Company (NEPCO), and the Electricity Distribution Company (EDCO).



PRIVATIZING THE ENERGY SECTOR

As a state-owned utility, NEPCO remains at the center of Jordan's restructured energy sector, responsible for the management, operation and development of the country's high-voltage transmission network. NEPCO maintains ownership of Jordan's transmission assets, but buys power from generation companies such as CEGCO, and sells it to distributors such as EDCO. Eventually, CEGCO and EDCO will be privatized, but NEPCO is expected to remain a state-owned monopoly to manage transmission and load-dispatching services across the country.

By splitting the country's energy assets into independent businesses, Jordan effectively divided the responsibilities into two parts, with policymaking and supervision on one side, and operation management on the other.

Most of Jordan's generation is provided by two main power plants: the 650 MW Aqaba power plant in the south, and the 400 MW Hussein power plant in the north. The country's transmission system runs along the north-south axis of Jordan, with distribution lines served from this 132 kV radial system. In addition to EDCO, other private firms providing distribution services include the Jordan Electric Power Company (JEPCO) in Amman, and the Irbid District Electricity Company (IDECO).

To further support the business processes of an expanding energy market, each of the newly independent companies needed a way to efficiently and accurately communicate and verify energy and financial transactions. Everything from the quantity and quality of power produced and delivered, to up-to-the-minute billing and time-of-use data had to be available to all market participants. As the administrator of this developing marketplace, NEPCO began evaluating ways to monitor metering points across the grid — every inter-tie where electricity is transferred from one business to another.

The first priority was to monitor settlement billing between NEPCO's transmission system and the generation assets of CEGCO. To do this, NEPCO installed an ION® enterprise energy management system from Power Measurement of Victoria, Canada. The Internet-based system uses a network of 150 ION 7500™ intelligent energy meters linked to four software servers to track and verify energy transactions between Jordan's generation and transmission companies.

ENTERPRISE ENERGY MANAGEMENT OVER PARALLEL NETWORKS

According to Faten Khuraishi, project manager for NEPCO, a key requirement of this system was to create a parallel communications structure that could provide each company with independent access to metering data from each shared inter-tie point. "Instead of NEPCO providing information to CEGCO, we wanted to give each company its own direct, independent access to metering information from each feed," explains Khuraishi. "But to verify the consistency and accuracy of the metered data, we also needed to build in a network of redundant meters — a parallel network — to act as a check to the main meters."

To do this, NEPCO equipped eight of its substations with a pair of revenue-accurate ION 7500 meters on each feed: one

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LEVERAGE RISK / REWARD WITH OUTSOURCED IT SECURITY

By Ron Lepofsky

Mundane IT processing of information security should be outsourced to a third party. Outsourcing raw processing such as analysis and correlation of huge amounts of SCADA or SOX related security data can generate considerable cost savings for clients, while also minimizing risk and arduous implementation. Some outsourcers further reduce risk for clients by offering control points for the client, such as proof of concept phases and clearly enforceable SLA terms.

PROOF OF CONCEPT: LOW RISK, SHORT TIME TO DEPLOY

A clearly delineated proof of concept initial phase for an outsourced security service provides the client with several benefits including:

1. An assessment period as to whether the deliverable meets the business requirements of the project, such as compliance with a particular security standard or making more time available for in-house security operations and architecture groups to focus on their core business goals.
2. Capped, fixed price for the entire deployment, including both monthly service costs and one time implementation cost.
3. Time for the client to evaluate all aspects of the deliverable against the SLA, plus evaluate such intangibles as ease of use and quality of knowledge transfer from outsourcer to client.
4. Time for the client to plan a full production deployment of the service, including making modifications to optimize the service for the specific and newly discovered business needs of the client.

BREATHING TIME TO CONTEMPLATE IN-HOUSE DEPLOYMENT

Once deployed into full production, an outsourced service provides the client with otherwise unavailable planning and assessment opportunities, including:

1. Knowledge transfer to their security operations and planning departments. This helps to prepare these groups to better assess whether the outsourced security service should eventually be deployed in-house, or remain outsourced.
2. Time to evaluate precisely what modifications if any would be beneficial with respect to scope or features of the security service, and the ability to incorporate these modifications into the price model for a potential in-house deployment.
3. The opportunity to further decrease security costs by levering the ability of the outsourced service provider to take on further operations.

CLIENT MAINTAINS CONTROL AND MANAGEMENT

Key to the client maintaining control is to find an outsourced service that sends only a data stream of security information to their service bureau for processing, but also leaves the data available at the client site for redundancy, for other uses, and for the retention of control.

A trivial but conceptually simple example is an outsourced email filtering service, where data can be redirected to the service outsourcer simply by redirecting email to them, but keeping a separate copy on the client site. Control of the process remains with the client, who has the last word on accepting questionable email, modifying the stringency of email filter parameters, and keeping a copy of all email on the client site.

In this process model where data is rerouted, the control benefit to the client is that data exporting can be shut down quickly.

For more sophisticated outsourced security services, such as IDS analysis and remedial recommendations or event log correlation and remedial recommendations, some outsourcers will provide the back-end processing. This frees more time for the client to more effectively manage their IDS and host security respectively. Thus a client retains control over the final process, such as IDS, host security, and firewall management, but the “heavy lifting” analytical work, and back end data base for data mining is done by the outsourcer.

ROI BENEFITS OF OUTSOURCING IT SECURITY SERVICES

Sophisticated IT security processes, such as analysis and recommendation services for IDS, IPS, event log correlation, security dashboards, and data mining capability for all of the above, all require considerable investment in:

1. Capital expenditures for software licensing and hardware.
2. Ongoing expenses for CISSP / CISA certified security analysts and security technology operations staff.
3. Ongoing expenses for software and hardware annual maintenance.
4. Extensive time and costs needed for ongoing training, and repeat training for staff turnover.
5. Expenses for all of the above in the cases of modification(s) to the initial process or replacement of the process if it does not operate as planned.

Outsourced services can and do provide substantial savings in both dollars and time, such as:

1. Savings of 25- 40% over the lifecycle of a project.
2. Equivalent costs to in-house deployment over the lifecycle of a project, but with no risk or budget constraints with regard to capital expenditures.

Savings are readily calculated over the lifecycle of a deployment. Some outsourcers will provide a prospective client with a simple, impartial spread sheet tool for this very purpose.

A more detailed financial analysis of cost savings may be found in an article titled IT Security Costs: Outsource vs. Self-Deploy, by the same author.

HOW DO THEY DO IT?

Outsourcers can afford to keep costs low for clients by sharing capital infrastructure costs and ongoing CISSP operations / support costs over all their clients.

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main meter and one check meter. These meters monitor the electricity delivered from CEGCO to NEPCO, and send the data up to a pair of ION RTU data loggers. Each substation is equipped with two data loggers: a main data logger receives data from all main meters in the station, and a check data logger receives data from all check meters in the station.

To oversee the data loggers, a pair of servers — a main server and a check server — was installed at each company's headquarters and configured to receive information from all metering points. Each main server monitors all main data loggers, and each check server monitors all check data loggers. Both servers are equipped with identical energy management and billing software, and both servers collect revenue and event information from the meters on the main feeds. With this arrangement, CEGCO and NEPCO maintain two completely identical — yet independent — metering networks, accessible from each company's corporate headquarters.

With "main" and "check" meters, RTUs, and servers, CEGCO and NEPCO each use two identical, yet independent, metering networks to monitor energy transactions from each company's corporate headquarters.

To supplement the main and check servers located at each headquarters, NEPCO installed additional workstation terminals at each substation so CEGCO and NEPCO engineers could access the system locally for onsite troubleshooting or research. Security safeguards such as a segmented network infrastructure, data validation, and multilevel user authentication ensure all billing and operational data is secure — accessible only to authorized users at each organization.

NEPCO's metering system uses high-quality Rittal electrical cabinets, equipped with humidity and temperature controls, to accommodate up to six meters each. The meters and servers communicate over NEPCO's existing fibre optic network — a dedicated Ethernet wide area network (WAN). In remote areas, substations can connect to the Ethernet network via modem over the public telephone network.

Every meter is also equipped with a built-in GPS (global positioning satellite) time-sync capability to ensure the accuracy and consistency of all time-sensitive data across the entire network.

HIGH ACCURACY METERING

In selecting an energy management system, NEPCO identified revenue accuracy as a key requirement, according to Dr. Abdallah Abdulrahim, managing director of AMPS, a Middle East-based energy consulting business that assisted with the implementation of the new system. "With a synchronized network of intelligent revenue meters, both CEGCO and NEPCO can verify the amount of energy produced and delivered," says Abdulrahim, "and the high-accuracy of these meters ensure that energy can be measured against the highest revenue-metering standards, such as IEC 60687, Class 0.2S. Also, each meter can help evaluate factors such as active and reactive energy, voltage and current levels, and power-quali-

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MEETING FUTURE DEMAND HINGES ON MANY FORMS OF GENERATION

By Don Horne

The second annual Energy Roundtable CERT Conference in Toronto focused on European investment in Canadian power markets, and included several speakers like AMEC's Brian Bentz.

Speaking on a comparison of wind farm projects in the United Kingdom and Canada, the President of Project Investments, Americas sees wind power working in co-operation with the other forms of generation as being the key to meeting future demand.

"My feeling, and that of the panel, is that the answer is going to be a mix of power - hydro, nuclear, coal, wind and solar - to meet generation targets and those of the Kyoto Protocol," says Mr. Bentz. "You can't get a consistent load with just wind or solar - you need the mix."

Comparing renewable projects in the UK with Canada, Great Britain needs some 5,000 gigawatt hours annually over the next five years to meet their targets. "In Canada with similar requirements (and target dates), the country would need to generate 7,000 gigawatt hours annually."

However, some of the greatest challenges in the UK market are the more stringent approval processes that stress public input.

"The environmental and planning approval process (for new wind power plants), some can be quite long (in the UK)," Mr. Bentz points out. "There can be considerable delays, as they ensure that these projects are well-approved through much public input."

This public input (for projects above 50MW) can include community consultation at the local level and statutory authority consultation from the central government, with no set time limit for the entire process.

MY FEELING, AND THAT OF THE PANEL, IS THAT THE ANSWER IS GOING TO BE A MIX OF POWER - HYDRO, NUCLEAR, COAL, WIND AND SOLAR - TO MEET GENERATION TARGETS AND THOSE OF THE KYOTO PROTOCO

Brian Bentz, AMEC president

In comparison, Canadian projects have enjoyed smooth sailing.

"The wind projects here have been holding to their time frames, usually 6 to 12 months."

The opportunities for investment in Canada's power sector are significant (see sidebar story, Record Year for Wind Energy Sector). In Ontario alone, it is projected that by the year 2020, $40 billion investment in energy infrastructure construction costs will be required. Growing private-power production and natural gas networks in British Columbia, a competitive electricity market in Alberta, renewable power generation in Quebec and the expansion of hydro power generation in Newfoundland and Labrador are among the array of other investment opportunities that exist.

"Climate change and the Kyoto Protocol are driving this," points out Mr. Bentz. "The security of the supply (oil and gas) will necessitate a broad mix of power sources, and the price of oil and natural gas - not to mention the cost and risk of fuel delivery - makes wind a more viable option. There is no cost and no risk to wind power generation." ET

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ty concerns like sags and swells, and harmonics.

"With both companies sharing the same meters at the same time, there's no variation in the data," explains Abdulrahim, "and with every meter in the network synchronized to the millisecond using a standard GPS signal, time-of-use data is absolutely accurate. Overall, this arrangement provides the shared monitoring, reporting and billing capabilities needed to help accommodate the needs of this growing market."

As part of Jordan's efforts to attract private investment to the country's developing energy sector, a reliable metering and communications infrastructure is helping to support the business processes between market participants.

Through the adoption of a synchronized, countrywide enterprise energy management system, NEPCO has set the stage for a competitive, financially viable environment for the production and sale of electricity.

In Victoria, Canada, representatives from Jordan inspect ION 7500 energy meters destined for the region's electricity supply network. (From left: Engr. Munir Najjar, project manager, CEGCO; Dr. Abdallah Abdulrahim, managing director, AMPS; Engr. Faten Khuraishi, project manager, NEPCO; Michael Gillis, project manager, Power Measurement.)

The author Anthony Tisot is a professional writer with Power Measurement, specializing in energy-management strategies and communications technology.

RECORD YEAR FOR WIND ENERGY INDUSTRY

Canada's wind energy industry has already broken its annual growth record in 2005 and is set to shatter it before the year is out. As of June 2005, Canada had installed 126 MW of new wind energy capacity, breaking the existing record of 122 MW established in 2004. Close to 200 additional MW of new wind energy capacity is expected to be installed in Canada before the end of 2005. Canada currently has 570 MW of installed wind energy capacity, enough to power more than 200,000 homes.

"With Canada's installed wind energy capacity expected to grow by close to 70% this year, 2005 will be remembered as the start of Canada's wind energy boom", says Robert Hornung, President of the Canadian Wind Energy Association.

"Over the next five years, federal and provincial government policies and targets are on track to facilitate a ten-fold increase in the size of Canada's wind energy industry."

Projects already installed this year include the Pubnico Point Windfarm in Nova Scotia and the Mont Copper and Mont Miller Windfarms in Quebec. In addition, wind energy projects are either under construction, or will begin construction this year, in Alberta, Saskatchewan, Manitoba, Ontario and New Brunswick.

"In addition to their environmental benefits, wind energy developments are also providing lease income to landowners, tax revenues to municipal governments, and creating investment and jobs in rural communities across Canada", says Hornung. "For example, three new facilities are currently under construction in Quebec alone to manufacture wind turbine towers and blades and to assemble wind turbine components."

The Canadian Wind Energy Association (CanWEA) represents more than 180 companies involved in Canada's wind energy industry, including wind turbine and component manufacturers, wind energy project developers, electric utilities and service providers to the wind energy industry. CanWEA's goal is to see 10,000 MW of installed wind energy capacity in place in Canada by 2010.

"While the growth we are seeing is significant, wind energy continues to develop more quickly in other countries", says Hornung. "With Canada's unparalleled wind resource, we can still do more to maximize the environmental, economic and industrial development benefits associated with wind energy." ET

Photo of a wind generation station in the U.K.

AUTOMATION PLUS REMOTE CONTROL PAYS OFF FOR KCP&L

By Betsy Loeff

Automation is a fine tool, but automation plus remote control is even better. Just ask the team at Kansas City Power & Light, where engineers tapped into an automatic meter reading system to better manage the capacitors on their distribution system. The project demonstrates how much utilities can gain when they harness the power of fixed-network communication for operational improvements. Following is a brief account of this award-winning approach to capacitor bank management.

TAKING CHARGE

In August of 1991, KCP&L was studying AMR capabilities and examining business case justifications for the technology. It turns out that weather had a big impact on whether the utility would choose CellNet's fixed network system, which it did.

"On August 29, we had a storm move in at the end of a hot spell," recalls Carl Goeckeler, lead distribution automation engineer at KCP&L. "The temperature plummeted 25 degrees in a three-hour period, but all of the buildings were still hot, so air conditioners kept running."

Air conditioner motors draw reactive power (VAr or MVAr*), which increases the amount of power utilities must generate. Reactive power often is likened to the foam atop a glass of root beer: It's there and must be produced, but it doesn't add billable or usable value. Reactive power can, however, add headaches for electric utility engineers.

This was certainly the case that stormy afternoon in the Kansas City area because simple thermostats controlled most of the utility's capacitors that stabilize voltage and minimize the amount of reactive power that the utility needs to produce. "As temperatures got hot, the capacitors turned on. As it cooled down, they'd turn off," Goeckeler says. Consequently, the capacitors shut down while the air conditioners kept running and calling for MVArs.

All of this occurred when KCP&L's large generating station, located in the utility's metropolitan area, was out of service due to an unscheduled outage. "We had too much reactive power on the system, which caused a lot of problems," Goeckeler adds. Generators were overburdened. Voltage sagged. And utility executives called for innovations to prevent a repeat of the troublesome event.

ENGINEERING ADVANCES

At the same time KCP&L's engineering group put a task force to work seeking ways to better control capacitors, the metering group was already eyeing CellNet's AMR. "We put the two concepts together," Goeckeler says. "We decided we could leverage the same communication system for capacitor bank control and monitoring as well as AMR."

> IN THE PAST, IF WE NEEDED EIGHT CAPACITORS, WE'D INSTALL 10 BECAUSE THEY WERE SO DIFFICULT TO MANAGE," GOECKELER SAYS. "NOW, IF WE NEED EIGHT, WE INSTALL EIGHT."

Working with CellNet, KCP&L engineers guided application of radio controls that could be installed in the capacitor controls themselves. Such special engineering was necessary because CellNet's system offered only two-way communication to CellNet communication CellMasters that aggregated information from multiple communications collectors that collect readings from various meters and relayed it onto the system's head end. "We implemented a two-way radio in the capacitor control that is similar to the radio used in the CellNet CellMaster," Goeckeler explains. "The radio is more expensive to deploy than the devices in meters, but it's much more sophisticated."

After testing and proving the concept, KCP&L began strategically retrofitting existing capacitors with the new radio technology. About 30 percent of the utility's 1,600 capacitors are on constantly, but the remaining capacitors are switched to go on and off as needed. Today, the utility has about 800 capacitors automated for on-demand switching via the CellNet system. But from the start, KCP&L knew that control was only part of the value the communication delivered. It also delivered information and savings.

ZAPPING THE BUGS

Although the automated communication with capacitors gave KCP&L engineers data every five minutes, the utility quickly realized that data is only valuable when you have the ability to use it to help manage your system. "It was like having all kinds of information on the Internet, and no way to search for it," Goeckeler says. "We had to develop a query tool."

With the query tool, the capacitor automation system became far more powerful. Engineers worked out a program to allow on-demand reads, which permits KCP&L to do troubleshooting, voltage profiles and current profiles, and examine power outages. In addition, engineers can view historical data. "If we have a low-voltage complaint, we can see if the capacitor was on when it should have been," Goeckeler says.

REMARKABLE RESULTS

The real beauty of KCP&L's system is the efficiency that capacitor control provides. Engineers quickly discovered the utility had more capacitors out in the field than it needed. "In the past, if we needed eight capacitors, we'd install 10 because they were so difficult to manage," Goeckeler says. "Now, if we need eight, we install eight."

In the early 1990s, when KCP&L

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CAN NEGAWATTS COMPETE WITH MEGAWATTS?

By Ronald J. Sutherland, Consulting Economist

The question of whether negawatts – energy conservation – could and should compete with megawatts (MW) of generating capacity was debated in the early 1990s with the overall result that subsidies required for negawatt (NW) programs did not produce sufficient benefits to justify the cost.

These demand side management programs (DSM) were also intended to be Robin Hood in reverse – they taxed the poor and subsidized the rich. The issue of NW competition is arising again as power pools, various states, and Canadian provinces attempt to maintain adequate resources to meet power needs at minimum cost and reduce peak prices. This article is based on a report distributed at the recent Ontario Power Summit and explains that NW can add significant economic value, but this value is highly sensitive to the market design.

If NW were able to bid along side MW in the Ontario wholesale market four major benefits would result: (1) average wholesale and retail prices would decline, (2) critical peak prices would also decline, (3) the wholesale market would become more stable, and (4) locational market power would be reduced. Ontario retail customers, and the regional economy, would obtain significant economic benefits. However, if NW were allowed to compete with energy suppliers in the PJM energy market (The PJM coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia), customers would not see these benefits. The critical distinction is that the energy market only in Ontario reveals efficient peak prices. In contrast, the separate energy and capacity markets in PJM, along with the installed capacity obligation in PJM, produces flat rate capacity pricing that subsidizes high cost peaking MW and discriminates against lower costs NW.

The critical characteristics of the negawatt program considered here are its dispatchability by the system operator, and that it produces measurable, reliable and verifiable results. The system operator must be able to use NW to meet load with the same level of reliability and controlability as when dispatching MW to meet projected load. A negawatt program could curtail or interrupt power use; but the program considered here is market based and competes in the wholesale market without a subsidy.

ILLUSTRATING A NEGAWATT PROGRAM

Table 1 is a simple and hypothetical illustration of the market effects of including 300 NW of supply alternative. Although the numbers are hypothetical and illustrative, the MW of capacity and supply of negawatts are roughly applicable to Ontario. We assume first that the system operator projects that 27,600 MW of capacity is required to meet projected demand. As in the Ontario auction market, the supply resources in Table 1 (see page 32) are stacked from the lowest price bid to the highest price bid. The lowest price bids of the first 27,600 MW of capacity will be accepted, with the marginal bid price determining the wholesale price received by all bidders.

Meeting peak demand requires a capacity level above 27,600 MW, which we illustrate by bids of capacity increments of 300 MW. This capacity increment is selected to correspond to a plausible increment in negawatts. The second column in Table 1 illustrates bid prices that define the supply curve where increasing levels of MW of capacity are required to meet peak demand. The third column depicts the larger price increments that characterize an increasingly inelastic supply curve. For instance, in this illustration, the increments in base-load capacity increase in bid price by 0.1, 0.2 and 0.3 cents. However, these price increments increase as installed capacity level is approached and the last two price increments are 1.0 cents and 2.0 cents respectively. The last bid of 300 MW of capacity increases the marginal bid price from 7.3¢/kWh to 9.3¢/kWh – an increment of 2.0¢/kWh. The market clears 27,600 MW of capacity being supplied at a market spot price of 7.3¢/kWh. Wholesale customers pay 7.3¢/kWh for each kWh they purchase during this auction period.

The illustration thus far assumes that all market adjustments are supply side and in the form of adding MW of generation to meet demand. We now allow for 300 negawatts to be economically viable at 5.8 ¢/kWh. With 300 negawatts entering the bid order, the 300 MW power plant that bid 5.9 cents drops down one place in the order (col. 4, Table 1). All higher price bids also drop down one place in the stacked order. The negawatt response has the effect of moving down the bid order of all higher priced MW supplied. The last 300 MW of supply required previously to meet demand is no longer required; it is displaced by 300 negawatts of reduced megawatt use (col. 5). As depicted in Table 1, the market again clears with 27,600 MW of resources being used to meet projected

Continued on Page 32

We are pleased to announce

Les Horswill

has joined Aird & Berlis LLP as an advisor to the firm's Energy Group.

Les has had an accomplished career in the Ontario government and the electricity sector. For more than 20 years he has helped shape policy, law and organizations in both the public sector and business in a variety of roles, including Assistant Deputy Minister Energy Policy and Environment and as Chief Executive Officer of Hydro One Remote Communities.

Les was responsible for the development of significant reforms to the electricity sector with legislation necessary to regulate electricity and introduce competition and private equity into the sector. He was provincial lead in the streamlining and negotiating of new Undertakings required for the sales of both Union Gas and Consumers Gas, and represented Ontario on air issues and climate change. He was responsible for Remote Communities' first PBR submission to the Ontario Energy Board and also was Hydro One's lead negotiator on the Five Nations transmission line.

A&B's Energy Group

The Aird & Berlis LLP Energy Group is comprised of lawyers who are recognized as experts in the energy law community. We understand the broad range of issues which you may face, and have assembled a diverse team of lawyers with many years of experience in the energy sector. Our lawyers practice in the areas of regulatory, corporate finance, environmental law, litigation, real estate, municipal and planning law, financial services and tax, and are well equipped to tackle your most complex matter.

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first started the capacitor bank control program, the utility routinely installed up to 50 new capacitors to its distribution system each year. Gaining control and data allowed engineers to relocate some capacitor banks, rather than install additional ones. And that happy circumstance lasted for eight years.

"By avoiding the need to invest in new capacitors, we saved around $2 million over a 10-year period," Goeckeler says. "We still install fewer capacitors each year than we used to. Now, we mostly add new capacitors to keep up with system growth of 2 or 3 percent per year." KCP&L's system grew 2 percent a year during the early 1990s too, but moving capacitors still took care of the utility's equipment needs.

The utility also saves money by avoiding the need to patrol capacitors annually. Periodic patrols are used to verify proper operation of the capacitor bank and control. With the CellNet system, KCP&L's engineers are able to determine all of this remotely. Eliminating the need to check 800 capacitors each year shaves close to $100,000 off the utility's maintenance expenses.

System efficiency results, as well. "This morning I looked at the system and we had only three more MVArs than we needed. The load was 1,600 Megawatts. That's virtually unity power factor," Goeckeler says.

Overall, KCP&L is achieving significant annual savings through reduced costs for capacitor banks, patrols and line loss. "In addition, our equipment is running more efficiently, so we're getting more life out of it," Goeckeler adds.

And perhaps the greatest contribution this program offered was the resilience it gave KCP&L. In February of 1999, the utility suffered a gruesome setback when a critical power plant in midtown Kansas City imploded. "The multi-story facility blew down to a few feet of rubble," says Goeckeler. "Suddenly, that crucial power plant wasn't available to produce power and stabilize system voltage and VArs."

Many voltage problems were proactively resolved during the two and a half years the utility spent rebuilding its lost power plant. KCP&L engineers used their query tools to find and turn on available capacitors by changing the automatic on/off set points. "What's neat about this is that we didn't need to just turn the capacitors on and worry about voltage getting too high. Ours turn off automatically when they're not needed."

On several occasions, KCP&L engineers used capacitors to augment system voltage and MVAr flow when the power plant was out of service for two and half years. "Meter reading may be the platform, the bread and butter of an AMR system," Goeckeler says, "but this is a classic example of how much more utilities can do to leverage that communication infrastructure."

* VAr or MVAr: Volt Amperes Reactive or Megavolt Amperes Reactive is the common abbreviation for reactive power, which is energy produced to accommodate needs of electric motors and other equipment.

AMRA is an abbreviation for the Automatic Meter Reading Association, of which Betsy Loeff is a news writer.

YOU SAID IT...

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LEVERAGE RISK

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For example, much training and cross training is required for CISSPs, and companies are reticent to over-train any individual, particularly if there is no prorated repayment schedule if the trained employee leaves within a year of receiving training. Even if there is a form of repayment, should the employee leave early, there is no ROI on the time spent achieving the designation. Outsourcers, on the other hand, completely eliminate this problem.

Similarly outsourcers can afford to utilize various security technologies and can better afford to switch or upgrade technology compared to their clients. This is due, in part, to the fact that technology manufacturers are willing to provide volume discounts and extra support to outsourcers, particularly when outsourcers provide valuable technical feedback to software developers.

CONCLUSION

A well composed outsourced IT security service should provide a proof of concept which can be used to both confirm and fulfill the client's business needs. It can also be executed at reasonable cost and with a quick time to deploy. As a result, a client's risks are minimized, should the client wish to proceed into full production. The client can lever the outsourced service to provide backend processing and additional CISSP support which they could otherwise not afford, while retaining control and full management of their internal IT security subsystems. Everybody wins!

Ron Lepofsky is the President and CEO of ERE Information Security Auditors, who are information security and financial disclosure/privacy compliance auditors.

Table 1
An Illustration of the Effect of 300 Negawatts on Wholesale Spot Prices

Total MW Supplied	Supply Price in ¢/kWh	Increment in Market Price in ¢/kWh	MW Supplied with 300 Negawatts Competition	300 Negawatts at 5.9 ¢/kWh	Total Resources Provided with 300 Negawatts	Supply Price in Cents/kWh with 300 Negawatts
Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
20,000	4.8 -	-	20,000	0	20,000	4.8
21,500	4.9	0.1	21,500	0	21,500	4.9
23,000	5.1	0.2	23,000	0	23,000	5.1
24,500	5.3	0.2	24,500	0	24,500	5.3
26,000	5.6	0.3	26,000	0	26,000	5.6
27,000	5.9	0.3	27,000	300	27,000	5.8
27,300	6.3	0.4	27,000	0	27,300	5.9
27,600	7.3	1.0	27,300	0	27,600	6.3
27,900	9.3	2.0	27,600	0	27,900	7.3

NEGAWATTS / MEGAWATTS

continued from page 28

demand, but this resource now consists of 27,300 MW of capacity at its margin bid of 6.3 cents and 300 negawatts of reduced demand, which enters the bid order at a lower price.

The first effect of increasing this supply alternative is to reduce the wholesale price to all customers. The market price is again determined by the marginal bid price, but with 300 negawatts of market based resources entering the bid order, the required resources are now brought on line at a reduced marginal cost. Table 1 illustrates that with the negawatt response, the spot market clears with 300 less MW of capacity, and at a reduced peak price of 6.3 ¢/kWh instead of 7.3 ¢/kWh.

Wholesale electricity markets, that use spot markets and produce real time prices, tend to produce a price duration curve that resembles an inverted hockey stick. Spot prices tend to be relatively flat during much of the year, but increase during peak periods, and increase very sharply during the few hours of greatest peak demand. An important feature of the NW resource is that it displaces the marginal or critical peak supply resource that produces the critical peak prices. Although market-based negawatts compete successfully well before a critical peak is reached, it is the marginal, high-cost, supply resource that customers no longer have to pay for. Negawatts therefore reduce peak prices and add price stability to the wholesale market.

From the perspective of the system operator, the negawatt program looks like a typical MW supply resource, not a demand side response. In fact, the impact of negawatts on the system is barely distinguishable from using an additional conventional MW technology to meet perceived load. The main effect of adding a negawatt program to MW supplied is to reduce average prices and peak prices. The same effect on prices would occur from adding a conventional generating plant to the mix of supply resources. A negawatt program is like a supply side resource, except that it meets projected load by reducing the use of low value electricity instead of producing more high cost electricity. The market effects on average prices and price spikes can be identical, customers see no difference, and the system operator sees little difference.

Local markets in Ontario experience price spikes when power demanded at one location exceeds that provided by available generators. Generating stations come in large discrete increments that do not always match locational power needs. Negawatts are available in tiny increments, and are widely dispersed across a market area. Given the dispatchability requirement of megawatts and negawatts, a system operator would be able to dispatch negawatts in locations experi-

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encing high locational marginal costs.

The diversification between negawatts and megawatts reduces supply risk that may provide greatest value in reducing locational price spikes.

THE PJM MARKET

The PJM wholesale market is significantly restructured from that of traditional regulation. This market includes auction markets for energy, capacity, and others for various ancillary services. These markets produce real time and day ahead spot prices. Floating prices are essential to achieve price-demand response. Although PJM wholesale market prices float, these prices do not reflect the actual marginal cost of supplying peak electricity demand.

According to the PJM market rules, an installed capacity margin (ICAP) is set to meet peak demand requirements. In the PJM model, this installed capacity level must also be maintained throughout the year. The cost of peaking units is thereby averaged throughout the year, just as in the traditional rate of return regulatory model. Capacity market prices vary randomly around an annual average price, regardless of capacity utilization. In the absence of peak prices that reflect real peak costs, price-demand responses, including market based negawatts, are not feasible. Just as in traditional regulation, in the PJM market, the high cost peaking units tends to crowd out lower cost negawatts, because these high costs are shifted to non-peak users.

With relatively flat retail rates, there is little incentive for retail customers to reduce their low value peak power in exchange for negawatts. With relatively flat wholesale prices there is limited opportunity for negawatts to reduce peak demand or peak prices.

THE ONTARIO MARKET

The Ontario electricity market is an energy market only (no separate capacity market) that includes an "energy reserve" of roughly 1400 MW above actual consumption. Wholesale prices are determined in a real time auction market. The Independent Electricity System Operator (IESO) issues forecasts of needed energy the following day. Generators and importers submit offers to supply electricity and the offers are stacked until the highest priced offer just provides the needed power. As stated by the IESO "All suppliers are paid the same price – the market clearing price. This is based on the last offer accepted" with real time prices.

Ultimate customers are divided into low volume and large volume customers, where large volume customers are those who consume more than 250,000 kWh a year. Large volume customers pay the wholesale price of electricity, which is a floating price determined in the auction market. Residential and small business customers pay an administered price, which is currently 5.0 ¢/kWh for the first 750 kWh and 5.8 cents for the additional electricity consumed during the month.

Stable and flat rate retail prices discourage price-demand response in this market. At present there is demand response in the wholesale market from the largest customers, but little price-demand response from residential and small business customers. A market-based negawatt program is highly feasible in the Ontario market.

The program provides a supply side resource, in the form of demand reduction that contributes to meet projected load at a lower cost than a MW only resource. It does so by reducing the use of low value energy when market prices indicate that such energy is expensive to produce.

FOOTNOTES

1 Paul Joskow and Donald Maron, "What Does a Negawatt Really Cost? Evidence From Utility Conservation Programs" The Energy Journal, Vol. 13, No. 4, pp. 41-74.

2 Ronald J. Sutherland, "Income Distribution Effects of Electric Utility Programs" The Energy Journal, Vol. 15, No. 4, pp. 103-118.

3 This report is available from the Electric City Corporation. See www.eleccorp.com

4 Most conservation programs do not have these characterstics, but the "Virtual Negawatt Power Plan" of Electric City Corporation has these properties.

5 The assumption of 5.8 cents is arbitrary. The only necessary assumption is that market-based negawatts enter the bid order before the last or marginal supply resource.

6 PJM Market Monitoring Unit, 2002 State of the Market Report, March 5, 2003, p. 68.

7 Information in this paragraph was obtained from the Ontario Independent System Operator site, www.ieso.ca.

8 Quoted from the IESO site, www.ieso.ca, "How the Wholesale Price is Determined"

Ronald J. Sutherland's presentation was commissioned by Electric City Corp.

COLLABORATIVE AGREEMENT WITH TJ/H2B SIGNED

AREVA T&D has entered into a collaborative agreement with US diagnostic testing company, TJ/H2b to provide on-line monitoring products of T&D equipment in exchange for TJ/H2b's diagnostic testing services of oil, gas and other insulating materials used in transformers, power circuit breakers and load tap-changers.

Under the agreement, AREVA T&D will implement TJ/H2b's transformer condition assessment tool and provide 24 hour, 7 day a week emergency laboratory services to its Utility and Industry customers throughout the United States and Canada. TJ/H2b is based in Sacramento, California.

The combined effort of AREVA's on-line monitoring diagnostic products and TJ/H2b's laboratory capabilities will enable both parties' North American customers to reduce the occurrence of failures, extend their equipment's life expectancy and help plan the replacement of aging transformers, circuit breakers and tap changers.

T&D: AREVA WINS 12-MILLION-EURO CONTRACT WITH EDF ENERGY IN THE UK

AREVA T&D has jwon a 12-million-euro contract with EDF Energy in the UK for the supply of gas-insulated switchgear.

They will replace and upgrade existing equipment at the Lodge Road substation, located in London. Under the contract, they will build, deliver, install and commission 26 bays of its F35-type 145kV gas-insulated switchgear and key ancillary equipment.

EDF Energy UK is the country's largest distribution network operator. In recent years, AREVA T&D has worked closely with EDF Energy to help modernize, strengthen and expand its electrical network to meet current and future electricity demands.

"Working together in this way has enabled us to develop a true understanding of the customer's specific needs. AREVA T&D was awarded this latest contract because our offer was the most compact, economical and adapted to the customer's requirements," said Stephen Burgin, President of AREVA in the UK.

ET

AREVA ENGINEER WINS 2005 UNO LAMM AWARD

Michael L. Woodhouse

AREVA T&D power electronics engineer Mr. Michael L. Woodhouse has been designated as the recipient of the 2005 Uno Lamm IEEE Award for his contributions in the field of high-voltage direct current (HVDC) technology.

Woodhouse has been involved in the technical design, development and application of thyristor valves for HVDC Converters, Static Var Compensators and Flexible AC Transmission Systems for over 40 years. He receives the award in recognition of his outstanding contributions in the development of high-voltage direct current (HVDC) technology and in particular for his technical achievements in the field of thyristor valves.

He is a technical expert for the AREVA T&D Power Electronic Activities Unit in Stafford, UK. He has written 13 technical papers and has actively supported the International HVDC community through membership in numerous technical working groups ranging from the IEE, IEEE, CIGRE and IEC. In 1992, he was awarded the GEC Nelson Gold Medal for his significant technical achievements in the design of thyristor valves.

Woodhouse is the fourth AREVA T&D recipient of this award. Previous winners include John D. Ainsworth (1983), Aleska Gavrilovic (1989) and Tom E. Calverley (1994).

The IEEE Power Engineering Society award was named after Dr. Uno Lamm, the Swedish engineer and father of HVDC technology. His work has allowed HVDC to be developed into an effective power system tool for long-distance energy transport, AC network interconnections, and system stability enhancement.

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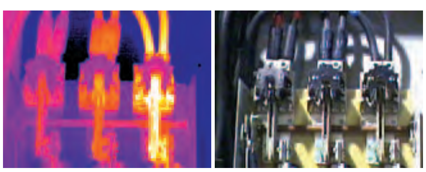

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Hydro Component Systems	25	www.hydrocomponentsystems.com	
High Voltage Supply	32	www.highvoltagesupply.com	www.electricityforum.com/products/High_Voltage_Supply_(HVS).html
Hubbell Power Systems	2,15,35,37	infoHPS@Hubbellonline.com	www.electricityforum.com/products/hubbell.htm
Incon	19	www.incon.com	www.electricityforum.com/products/incon.htm
InfraRed Imaging Solutions	37	www.iristhermography.com	
KEMA	7	www.kema.com	www.electricityforum.com/products/kema.htm
Kinetrics	10	www.kinetrics.com	
Lineal	28	www.lineal.com	
Magna Electric Corp.	12	www.magnaelectric.com	www.electricityforum.com/products/magna.htm
Mikron	9	www.mikroninfrared.com	www.electricityforum.com/products/Mikron_Infrared_Inc.html
Morgan Schaffer	39	www.morganschaffer.com	www.electricityforum.com/products/morgan.htm
MTE Corporation	34	www.mtecorp.com	www.electricityforum.com/products/mte.htm
Optimized Devices	37	www.optdev.com	www.electricityforum.com/products/optimized_devices.htm
Powertech Labs Inc.	30	www.powertechlabs.com	www.electricityforum.com/products/powtech.htm
PowerTran Company	31	www.powertran.ca	www.electricityforum.com/products/powtran.htm
RONDAR Inc.	5	www.rondar.com	www.electricityforum.com/products/rondar.htm
Synergy	23	www.synergyinc.com	www.electricityforum.com/products/SYNERGY_ENERGY_INC.html
techniCAL Systems 2002	24	www.technical-sys.com/	www.electricityforum.com/products/technical_systems2002.htm
Velcon Filters	21	http://www.velcon.com	www.electricityforum.com/products/velcon_filters.htm