Newton-Evans Research Company's

MARKET TRENDS DIGEST

for the Computer, Communications, and Controls Industries

Volume 18 WEB SITE: http://www.newton-evans.com Third Quarter 2002

Electric Utility Operations Control Center Issues and Trends in Mid-2002: A Global Perspective

Over the past few months, Newton-Evans Research Company has been collecting information from more than 100 countries around the world regarding the use of EMS and SCADA technology trends in the world's control centers. It is clear that this market is continuing to evolve and is moving to increase energy security, while at the same time, taking advantage of modern operating systems, open protocols and data communications methods.

It is apparent that there is a trend in small- to mid-sized utility operations centers, including regional control centers (RCCs) and district control centers (DCCs) in many countries, to move to Windows-based operating systems. However, for the larger EMS systems and national/regional control center level systems, UNIX remains the operating system of choice.

Internationally, there is significant use of IEC communications protocol standards such as TASE2 and IEC 680-70-10x, while in North America there is ongoing discussion of open protocols, with many sites now using ICCP and a mix of UCA and DNP3.

The major players active in North America for the larger control systems are the same as those active in other world regions, including ABB, Alstom, GE Power Systems and Siemens. However, the second tier of suppliers is different, with most having a regional orientation, while some RTU and substation integration specialists pick and choose partners on an opportunistic basis anywhere there is an opportunity to be had.

There have been some amazing changes in the market over the past few years. Here are some of Newton-Evans observations.

First, the developing nations of the world are rapidly coming up with the operational insight and engineering knowledge to staff and operate sophisticated control centers for their countries' electrical infrastructure. No fewer than 50 countries have acquired major new national or regional control center technology since 1997. Many of these had to first build a control center, and develop a telecommunications infrastructure prior to implementing the EMS, load dispatch or distribution SCADA. How have they accomplished this, when it appears that many Western European and North American centers have had such a difficult time "keeping up" with the sweeping changes in information and automation technology?

Here are our thoughts on how these countries are finding the wherewithal to rapidly move ahead. First, funding is now widely available for well-➥

****

TABLE OF CONTENTS

Substation Automation & Integration Study. . . 3
Substation Battery Management 4
Importance of .2% Revenue Accuracy 5
Upbeat Outlook for Protective Relays 6
Environmental Advantages of DG 8

****

thought out energy infrastructure projects in developing nations, with more than 15 international financial organizations ready and willing to invest in energy-related infrastructure development projects. Such projects include the funding of large EMS/SCADA systems, control centers and telecommunications development activities that enable grid access to be provided to millions of additional people each year.

These financial institutions range from The World Bank, Asian Development Bank, Arab Development Bank, African Development Bank, to a large array of government-sponsored funding authorities from Western European and North American nations.

Formal training is available for would-be systems operations personnel from developing nations in some countries in which government-industry-academia collaboration is well established. Sweden probably leads in such efforts, with France likely next, both providing training for many operators/engineers that could not otherwise avail themselves of such training courses in their homeland.

In the telecommunications arena, a recent trend in many countries has been brought about by the dual concerns for energy information security and the need for transmission line insulation. These needs have led to the installation of thousands of miles of optical ground wire (OPGW), optical fiber lines traveling along the transmission line and serving as an overhead ground wire and as a high-bandwidth telecommunications method. OPGW use for SCADA/EMS communications is becoming prevalent in many regions of the world.

Another trend we have picked up on in several site visits with utilities and suppliers this year is that of integrating the EMS/SCADA business operations with related units, such as Protection and Control or Substation Automation or Communications, if such “sister” units exist within the company.

We first observed such an example of this in the 1990's with the success of GE Power Systems is its Energy Management Services business unit. This unit was the first to unify the EMS/SCADA business with other technology-based T&D components, such as the Smallworld GIS unit and also with the inclusion of several substation integration and automation-related businesses based in North America and abroad, reporting through Calgary.

ABB has unified its marketing approach to the world’s electric power delivery industry, with the Utilities sector now forming a huge portion of the company’s total business. In addition to Power Systems, the company has a Utility Partner organization, and more importantly, the ABB Network Management group that includes units addressing markets for substation automation, utility communications, power systems operations, market operations, energy trading and energy retailing.

Meanwhile, Siemens Corporation has been successfully integrating the formerly autonomous Telegyr SCADA/RTU operations within its EMIS business area in North America. As part of the Siemens Power T&D organization, EMIS reports in with Metering and Relaying. Globally, Siemens PT&D includes the above segments plus HV and MV equipment manufacturing.

Alstom has just reshaped part of its vast T&D business, which encompasses network planning, operations and maintenance, power conversion, and T&D equipment manufacturing and energy management and markets. Alstom’s EMM business that internationally had already included telecommunications infrastructure development activities with its EMS/SCADA business, has just added metering and protection and control business units, to form the Alstom Energy Automation and Information business operation.

These recent business realignments among the Big Four will better serve the evolving needs of T&D organizations and operations/engineering units in particular, in electric utilities throughout the world, in our view. Each of these "majors" has developed a series of IT-intensive responses to the changing needs of restructured electric utilities and energy delivery businesses and each is closely following the regulatory changes underway around the world. ➥

Smaller "utility information technology" specialist suppliers continue to provide excellent solutions and serious options to meet the needs of control center-based operations staffs around the world. While some are strictly regional players, many are adopting to the needs of an "export" market, depending on the size and structure of the home market in which the supplier is based.

The chart below (Figure 1) shows the sub-Saharan African countries, listing their principal government-operated national utility abbreviated name, and key control center-based EMS/SCADA/DMS suppliers.

- Chuck Newton

Country	National Utility			National Utility	Known EMS/SCADA/DMS Installations
	ENE				None
	BPC			Electricity Board	Alstom
	SONABEL			Mozam.	DaVinc/ 1st Energy
	SONEL				Siemens/ABB
	STEE				Alstom (Procett)
Congo	SNEL				Siemens
	Electricite du Djibouti				ABB (SCADA)
	SNE				Siemens(NCC)/GE(RCC)/ ACS (DCC)
	Eritrea Electric Authority				Alstom (Procett)
	Ethiopia Elec. Pwr. Co.			Board	DaVinc, 1st Energy
	Elec. Co. of Ghana				Ocelot/Gryphon Design, ABB
	CIE				Siemens
	Kenya Power & Light Co				ABB
	Malawi Elec. Supply Co.				ABB, SAT (SAS)
	SOGEM				ABB

Now Underway: Research Study on the Worldwide Market for Substation Automation and Integration Programs

In 1997, Newton-Evans Research Company conducted its first extensive research program provide a clear view of the worldwide substation automation and integration marketplace among electric utilities. In 2000, the second series of studies was completed. The company is now in the first phase of its third research program on this topic, covering the 2002 to 2005 time frame. The product of this study will be a four volume series of reports covering 1) North American Market 2) International Market 3) Supplier Profiles, and 4) Market Forecast and Assessment. Call 410-465-7316 or email jsmall@newton-evans.com for further information.

Substation Battery Management and Monitoring

Newton-Evans has recently completed a research study concerning substation battery management and monitoring.

In the U.S., larger and mid-size substations most often have batteries used as primary (or secondary, backup) power sources. Many small substations do not have battery power. Our estimated percentage of substations equipped with such batteries is more than 90% of transmission substations and about 55% of distribution substations.

Substation batteries typically provide DC supplies for protection and control equipment (principally relays), and also provide trip and close current to circuit breakers.

IEEE Standards Coordinating Committee 29 on Stationary Batteries is responsible for all activities related to battery technical specifications.

Substation battery types include rechargeable lead-acid (unsealed), VLRA (valve regulated lead acid - sealed), nickel-alkaline and other types.

Increased power requirements to provide electricity to more substation devices, and often more energy-intensive devices in typically larger substations, mean the use of a larger battery is required.

The survey conducted by Newton-Evans for this report indicated that 125 volt/60 cell batteries are the most prevalent type of battery. 48 volt/ -40 cell arrangements follow in importance. Several utilities indicated having a few larger batteries, typically 250-volt units, and typically associated with power generation stations. Many utilities also use smaller 24-volt units in smaller distribution substation applications.

Typically, NICAD batteries are used in the more demanding, rugged outdoor environment. These batteries cost a multiple of the indoor substation batteries, which are more often likely to be lead acid, and cost about $2,000 per battery for 125 volt DC units. Usually each set of battery pairs has its own charging unit.

Remote monitoring of substation batteries is being done for many utilities, and is normally being done via SCADA. However, there are also sub-system level battery monitoring units available, including systems that monitor the battery chargers, and perhaps not the batteries themselves. None of the utilities that were interviewed for this study were using special monitoring subsystems. All were using SCADA systems to perform battery and battery charger monitoring. The monitoring function include high/low voltage; ground fault; AC input; hydrogen levels for indoor units.

In power generating stations, most batteries are charged via a motor-generator set, and the genset and battery condition are monitored at regular intervals throughout the day.

TABLE 2

Type of Battery	Estimated # of Sets Installed	Monitoring Method (BMSS - Battery Monitoring Subsystem)	Percent Monitored by Each Method	Estimate of Non-Monitored Battery Units
250V (60 cell+)	6,500	SCADA/BMSS	65% / 30%	5%
125V (40-60 cell)	21,000	SCADA/BMSS	75% / 15%	10%
48V (24-48 cell)	12,000	SCADA/BMSS	60% / 10%	30%
24V (<40 cell)	9,000	SCADA/BMSS	40% / <10%	50%

Revenue Accuracy of .2% Most Important Function for High End Meters

Newton-Evans Research recently completed a study on the use of high end meters, which, for this study, was defined as a meter with enhanced functionality such as multiple communication options or advanced power quality monitoring that is used in transmission or distribution substations, or at a large C&I.

Respondents were asked to indicate the requirement level (required, optional or not needed) for 14 high end meter functions in their utility. These functions were: revenue accuracy (.2%); revenue accuracy (.5%); easy programmability; outage notification; waveform capture; sag detection; over/under voltage; over/under current; voltage harmonics; current harmonics; other power quality functions; alarm paging; GPS time synchronization; and, local web interface.

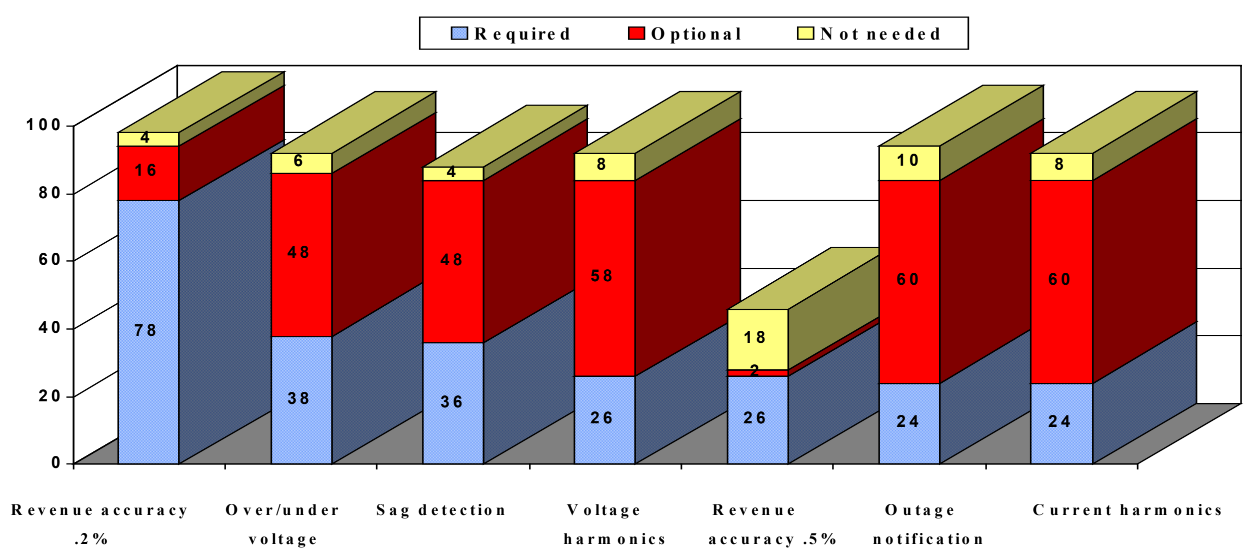
By and large, most of the listed features were considered optional. Revenue accuracy (.2%) was the only feature to be considered mandatory by a majority of the respondents (78% so indicating).

Other important features did include: over/under voltage (38% citing as required); sag detection (36%), and revenue accuracy of .05% and voltage harmonics, both at 26%.

From respondent comments provided during the interviews, it is clear that the use of high-end meters is strongly application-dependent.

See Figure 1.

Figure 1
Requirement Level for High End Meter Functions in Terms of Importance to Utility



In the study, utility officials were also asked about the necessity for data communications from these meters to be transmitted to any existing utility systems or to the end customer at C&I sites.

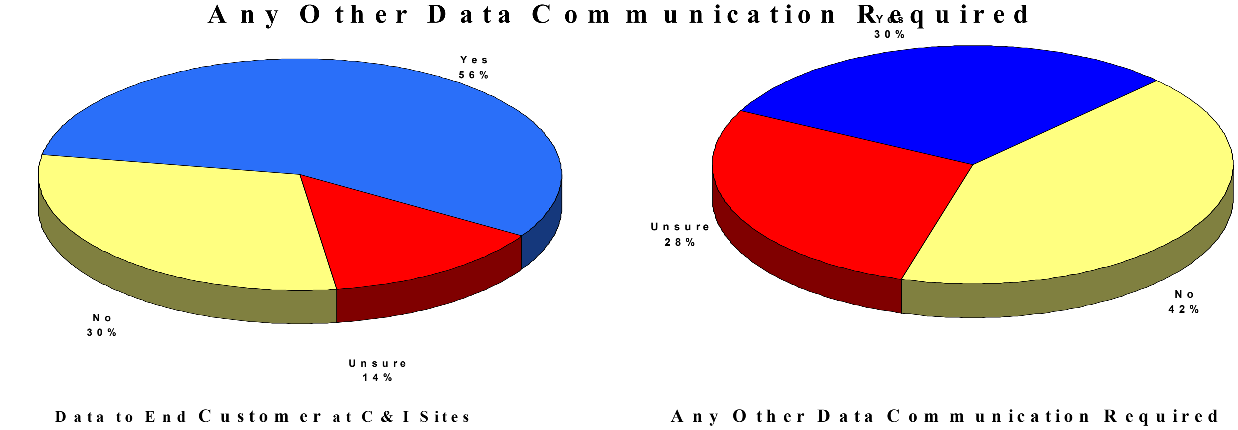
Ninety percent of the respondents from 50 utilities indicated some level of need for the high-end meters to transmit data to one or more currently installed information management or control or monitoring systems. Only six percent attached no value to this data transmission, and the remaining four percent were uncertain.

Figure 2 contains this communications data.

The use of communications from high-end meters to any existing utility system was important to every utility subgroup (investor-owned, public power, and rural electric cooperative). Both SCADA and AMR systems were indicated as the primary systems linking with high-end meters.

In the second part of this question, 56 percent of the respondents indicated a need to transmit meter data to their C&I customers. Thirty percent saw no need for this data transmission, and the remaining 14 percent were unsure. Again, this was equally important to each subgroup of utilities.

Figure 2
Necessary for Data from High End Meters to be Transmitted to End Customer at C & I Sites or Any Other Data Communication Required



Outlook for Protective Relays Remains Upbeat, with Subtle Differences in the International and Domestic Markets!

The percentage of digital relays in the mix of all protective relays used by utilities continues to increase. Nearly 40% of all generator and transmission line relays installed in the U.S. are now digital units. The majority of new and retrofit units being purchased are also digital relays, but in some of the protection applications studied, EM and solid state relays continue to have a niche market position. Internationally, the majority of new relay purchases are also digital, but at a lower percentage of the total than found in North America.

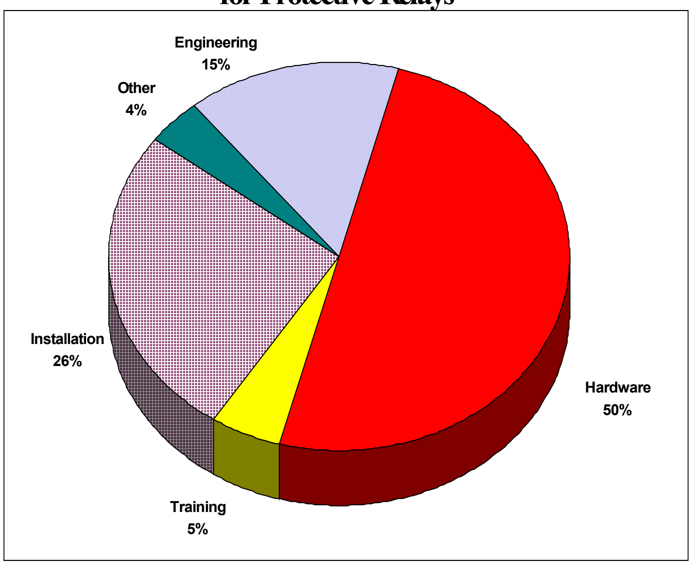
The need for external assistance that may be needed by the utility for relay-related services proved to be the issue that shows the greatest discrepancies between North American and international system protection officials. While one third of the U.S. and Canada utility officials already need training classes, and 20 percent need design assistance for protection schemes, and/or installation support services, this rate more than doubles in the international arena. Worldwide, the upsurge in requirements for third party technical services continues a trend observed in several recently completed studies, pointing up an ever-increasing reliance on outside support services for activities that are being outsourced more and more frequently by electric utilities.

Purchasing patterns for distribution relays continue to indicate a variety of approaches in use. Most popular in North America is to purchase loose and unmounted relays for retrofit distribution applications, with little redundancy in the design of distribution protection schemes continuing into mid-2002.

Interestingly, in mid-2002, about one quarter of a typical relay budget in a North American utility goes for installation services, and another 16 percent is allocated for other engineering services. Just less than one half of the total relay budget is for relay hardware. This varies from international utility practices. In many countries, relay hardware accounts for two-thirds of the budget, installation accounts for 15% and engineering for 12% of the budget. See Figure 3.

Figure 3 North America

Approximate Budget Allocation for Protective Relays



Fiber optics is playing an increasingly important role as a relay communications (data transmission) medium both in North America and internationally. Nearly one half see the role of fiber important for transmission line distance and current differential relays, as well as for distribution feeder and transformer relays.

****

MARKET TRENDS DIGEST (ISSN 0891-037). Newton-Evans Research Company, Inc. publishes *MTD* for the applied technology industries, utilities, and energy companies. Editor: Loretta Smolenski. For further information, phone or write to Newton-Evans Research Company, 10176 Baltimore National Pike, Suite 204, Ellicott City, MD 21042. Telephone (410) 465-7316. E-mail us at lsmolenski@newton-evans.com. Please visit our website at: www.newton-evans.com.

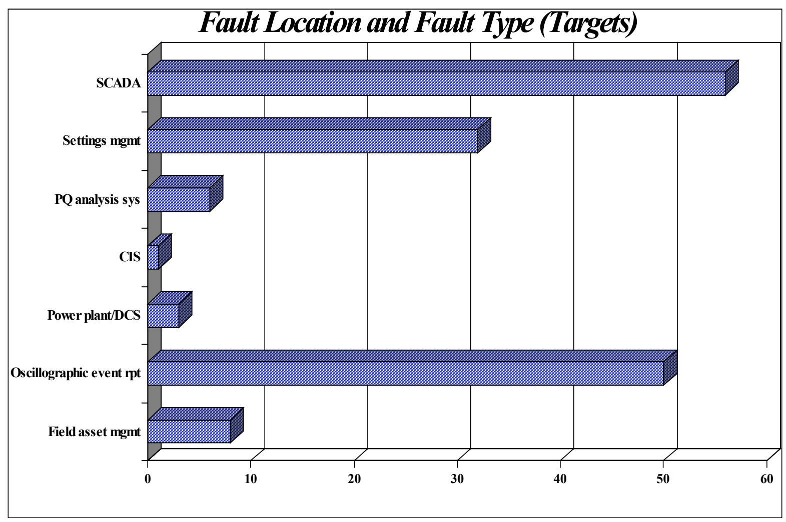
****

Relay data is being used by more related operational and engineering applications today than ever before. SCADA systems received relay information on analog measurements, relay status, and for fault locations and fault type indicators. Remote engineering workstations use oscillographic event report to assist with fault location, and to a lesser extent these workstations are used for fault location and type indicators.

Both domestically and internationally, SCADA systems now receive more relay data that indicated in earlier studies. Remote engineering workstations account for a substantially higher level of involvement using relay data internationally then they do in North America. See Figure 4 for the information on fault location and fault type.

Figure 4 North America

Systems to Which Relay Data Is/Will Be Transmitted



Internationally and domestically, the outlook for relay purchases is moderately upbeat, with an expanded number of relays planned for purchase in each year of the four year planning horizon.

In summary, the outlook for protective relay use can be summarized as: 1) continuing to evolve toward the digital world, 2) remaining upbeat for manufacturers and utilities, and 3) indicative that our industry is more reliant than ever before on the availability of competent third party services for upgrading T&D infrastructure and support of internal operations and staff.

Environmental Advantages Indicated as Main Benefit of Distributed Generation to International Respondents

In the second quarter of 2002, Newton-Evans Research Company published the third and final volume of a major research initiative that studies the role of distributed generation (DG) in business plans in the electric power industry worldwide.

Volume I examined the role of distributed generation in North American utilities and Volume II examined this role in international utilities. Volume III profiled more than 20 domestic and international suppliers of DG.

In our previous MTD, two topics from the North American report were discussed: potential economic, operational or customer-based benefits and the impact of distributed generation units on transient stability. This issue talks about the potential benefits based on the international study, and also the type of ownership of distribution generation equipment found among international utilities involved with distributed generation programs.

One-half of the international group indicated joint ownership by utilities and customers. One-third indicated utility ownership of all DG units, and 17 percent cited customer ownership of DG assets. Among the North American respondents, 34 percent indicated that all DG equipment is customer-owned. Forty-two percent indicated that utilities and their customers jointly owned the equipment, and the remaining 24 percent indicated that all DG equipment is utility-owned.

To the group of international utility officials, the five key benefits included potential environmental advantages, improved customer satisfaction and service, peak shaving possibilities, increased voltage support, and reduction or deferment of T&D line construction. In the earlier North American study, the most important benefits, according to the rankings provided by 177 North American officials were peak shaving, customer satisfaction, and increased service reliability.

See Figure 5 for this international data.

For special pricing information on the DG three-volume study, call Newton-Evans at 1-410-465-7316 or email to jsmall@newton-evans.com.

Figure 5 - International
Ranking of Benefits of Distributed Generation
(where 1 = least beneficial to 5 = most beneficial)