PRESENT AND FUTURE INTEGRATION OF DIAGNOSTIC EQUIPMENT MONITORING

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ABSTRACT

Like most electric utilities, the Omaha Public Power District (OPPD) has installed various equipment condition monitoring (ECM) devices. These devices are monitored locally, or monitored remotely via a dial-up connection. The data downloaded through the remote connection is stored in individual databases, and not in the corporate data warehouse. OPPD discovered a potential catastrophic failure with a generator step up transformer, and was able to "manage" the problem and avoid the ramifications of an unexpected failure with diagnostic equipment monitoring. Last year OPPD began a substation integration and automation project under EPRI Tailored Collaboration, resulting in a standard integration architecture for the intelligent electronic devices (IEDs) in the substation. This architecture is capable of integrating ECM IEDs, resulting in the benefits of additional device data extraction and the sharing of this data throughout OPPD utilizing the corporate data warehouse. Integration architectures will be installed in two pilot substations that include ECM IEDs. In addition, a Substation Automation Training Simulator (SATS) with ECM IEDs will be used by OPPD for training, testing and development.

INTRODUCTION

The advent of industry deregulation has placed greater emphasis on the availability of information, the analysis of this information, and the subsequent decision making to optimize system operation in a competitive environment. The IEDs being implemented in substations today contain valuable information, both operational and non-operational, needed by many groups within the utility. The challenge facing utilities is determining a standard integration architecture that meets the utility's specific needs, and can extract the desired operational and non-operational information, and deliver this information to the users who have applications to analyze the information. The ECM IEDs are a major source of this information, and can be integrated into the substation architecture identical to the other substation IEDs, such as the relay IEDs.

EXISTING EQUIPMENT CONDITION MONITORING DEVICES

The following equipment condition monitoring devices are currently installed at OPPD:

- Six GE Harley LTC-MAP 2126 devices on three transformers in one substation
- Six GE Harley LTC-MAP 2130 devices on two transformers in one substation and four devices on two transformers in another substation
- Four GE Harley LTC-MAP 3030 devices: one on the generator step up (GSU) transformer at Nebraska City Plant, two on 345/161kV 300/400/500 MVA auto transformers, and one on a GSU peaker unit transformer

The on-line Maintenance Action Planner (MAP) for load tap changers (LTCs) continuously monitors performance data from various types of sensors, such as temperature and current. It stores this data in non-volatile memory for downloading to a personal computer. These monitors have analog input channels, which are used for sensor, current, and voltage inputs, and digital input channels. OPPD monitors the main tank, LTC, tap position, phase current, motor current, voltage, coil, contacts, and other items. Samples or readings are taken every five minutes, and are stored locally until the data is downloaded. The downloaded data is reviewed every morning. The four conditions that are reported are:

1. OK (indicated by green)
2. Alert (indicated by yellow)
3. Alarm (indicated by red)
4. Communication failure (indicated by blue)

The majority of the non-OK reports are for communication failures. OPPD is sampling twelve devices every five minutes and each device has one or two cards with thirteen to seventeen ports on each card. In other words, there are a lot of data points being sampled. It is common to clear several hundred-communication failures every week. The majority of the other reports are for the partial discharge (PD) channels, since OPPD has not standardized the settings in the partial discharge monitors.

- Four GE Harley T-MAP 3100 devices

The on-line transformer Maintenance Action Planner remotely gathers and processes data in order to access and communicate the on-line condition of transformers. The analog input channels are used to monitor partial discharge (six different sensors and one additional for ambient PD), currents, motor, top oil, and bottom oil. The digital input channels are used to monitor loss of AC, fans, contacts, GenBus, TCG (total combustible gas), and winding temperature.

- One GE Syprotec TNU (transformer nursing unit) on a 345/161kV 300/400/500 MVA auto transformer

This unit is part of an EPRI TC project. It is called up separately. It samples the oil for dissolved gases and saves the data in the CPU in the TNU. This unit was to sample the gases in the head space (gas space above the oil in the main tank). This portion of the TNU has not worked on the unit at OPPD, resulting in dropping this part of the EPRI project. The TNU does a good job of displaying the results of the on-line DGA (dissolved gas analyzer) results. There have been some fluctuations in the DGA readings due to the wide ambient temperature swings experienced in Nebraska.

- One Mitsubishi DGA also mounted on the Nebraska City Plant GSU

The Mitsubishi DGA does the same thing as the GE Syprotec TNU unit. Unfortunately, the only way to get the data from the unit is to take a laptop to the unit and download on site. This is currently being corrected.

In summary, OPPD accesses these monitors by connecting a computer locally on site or by dial up connection and downloading the data. Each type of monitor has its own software for accessing the data. All data is stored in an individual database (not the corporate data warehouse). Most of the monitors are set up to download the data on a regular interval, such as every night.

Engineering Technical Support, Substation and System Protection, and Substation Engineering are all involved in the monitoring program. Technical Support has the overall responsibility.

OPPD is going to add monitoring on all new critical substation class transformers. The possibility of adding monitoring to circuit breakers and other substation equipment exists for future applications.

EQUIPMENT CONDITION MONITORING RESULTS

One specific incident will be discussed where equipment condition monitoring detected problems with a GSU. OPPD made modifications to the FOA cooling system in an effort to mitigate the occurrences, and reduce the duration of the internal electrical disturbances.

History

Nebraska City GSU #1 is a 17.1 kV - 345 kV, 600/672 MVA Westinghouse shell-form transformer, built in 1978. This transformer is part of a family of Westinghouse generator step-up transformers, which have exhibited two known problems:

- Uninsulated T-beams - Core laminations can come into contact with the vertical members of the T-beam that are not insulated. The subsequent hot spot involving the magnetic circuit in the transformer will produce a variety of hot metal gases, including acetylene. The severity of the heating and the associated insulation breakdown is directly related to the rate and composition of the gases detected in the insulating oil.

  (Note: The uninsulated T-beam situation has been recognized for several years as the principal cause of problems associated with these transformers. However, OPPD tests indicate that the failure mode described below may be a more serious concern.)

- Open Winding Failures - Turn-turn failures in the high-voltage coils of these transformers have been occurring at an alarming rate. The root cause of the problem is usually difficult to determine since the failure is typically violent, and causes substantial coil and core damage.

  The uninsulated T-beam problem will cause low level gassing, but did not show itself to be progressive. The open winding problem, however, is a serious situation that should be immediately addressed and continuously monitored.

  With these problems known, an extensive monitoring package was added to the OPPD transformer in October 1997. The monitoring package installed consisted of a GE Harley T-MAP 3100 system (Figures 1 and 2). This system was designed and installed to monitor the following quantities:

  - A, B, and C phase 345kV Amps
  - A, B, and C phase Generator Bus Volts
  - Cooling Group 1 Amps (Fans + Pumps)
  - Cooling Group 1 Contactor Status
  - Cooling Group 2 Amps (Fans + Pumps)
  - Cooling Group 2 Contactor Status
  - Top & Bottom Oil Temperature
  - Ambient Oil Temperature
  - Partial Discharge Detection System
  - Various Transformer Alarms also monitored by Power Plant

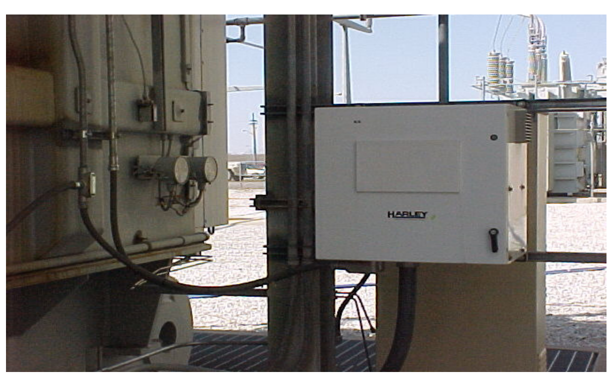

Figure 1 – GE Harley T-MAP 3100

Figure 2 – GE Harley T-MAP 3100 PD Sensor

Early Detection

At the time the transformer monitoring system was being installed, an upgrade was being implemented at the Nebraska City generating plant to increase capacity by ~30 MW. Increasing the maximum net GSU transformer output from 660 MVA to 692 MVA required OPPD to operate the transformer above its original nameplate rating of 672 MVA. Given the transformer's history of thermal problems, the decision was made to replace the original coolers with newer, larger, more efficient units. This work was completed in late fall of 1997. With the new coolers installed, the GSU transformer operated at full power throughout the summer of 1998 without generating the thermal alarms that had previously plagued the unit.

Routine checking of data brought random acoustic partial discharge (PD) events to the attention of OPPD and customer service personnel at GE Harley. With experience gained through participation in the tests of a TXU Electric transformer and tests at the Ramapo Substation of the Consolidated Edison Company of New York, the combination of low oil temperature and PD events signaled the possibility that the static electrification cycle of charge build-up and discharge was occurring.

The on-line partial discharge system detects the highest level of acoustic emission activity each second and records the highest level in each minute. Six piezo-electric sensors (Figure 2) with a frequency range centered at about 150 kHz were installed externally on the transformer tank wall. An additional "ambient" sensor was installed separately to determine whether acoustic activity is due to a source external to the transformer.

The most frequent and the highest levels of activity occurred on the south side of the transformer tank close to the top. There was no activity in the ambient sensor, indicating the acoustic source was within the transformer.

The pattern of acoustic activity increased in intensity of count level in several cases at about 50°C and noticeably at temperatures below about 40°C. This occurred even with only one bank of cooling in operation.

Cooling Modifications

OPPD decided to uniformly reduce the cooling on the four manually controlled coolers. These coolers are considered the base-cooling group, and operate anytime the transformer is energized. Consequently, these coolers would be the only cooling operating during the light load, low ambient conditions. Each cooler assembly consists of one oil pump forcing oil through an oil cooler that has four fans forcing air across the radiator fins. In order that the reduction of cooling was uniform, one fan from each of the four manually controlled cooler group assemblies was disconnected (Figure 3).

Figure 3 – Blocks indicates fans removed from service

The results of the modifications revealed that the oil temperature increased during "light" load conditions above 35°C. The PD readings decreased to previously observed values, and the power plant's status returned to normal. The GSU cooling returned to normal (all fans back in service) in early April to prepare for upcoming "high" load conditions.

During June 1999 a close trip sequence occurred and the subsequent signature of the transformer changed completely. The pattern of discharges increased sharply. Additional cooling modifications were needed to maintain the oil temperature above 30°C and reduce the oil speed to reduce the risk of static electrification.

In July 1999 the cooling pump control scheme was changed from 4-4 operation to 2-3-3 operation. The first two pumps were always on. The first group of three pumps turned on around 55°C to 60°C, and the second group of three pumps turned on around 70°C. These cooling modifications were done with the transformer on-line. The GE Harley system was used to control the second and third group of pumps, and a Qualitrol system was used as a backup system for pump control.

Conclusions

The life of the transformer was extended for the six months needed for OPPD to procure and receive a replacement transformer. During this period there was extensive monitoring of the transformer with multiple monitoring systems.

The events in this example were real. Decisions reached were based partly on empirical data received from the GE Harley monitor, and partly on previous knowledge learned through various research projects and technical reports.

The Nebraska City GSU #1 operating conditions were temporarily modified in an effort to reduce the likelihood of a prolonged incidence of internal static electrification. Empirically, OPPD was successful.

Mitigating the risk of critical equipment failure, and the subsequent costs associated, remain the predominant justification for the continuing utilization of on-line monitoring equipment.

An unexpected failure of this transformer would have caused OPPD to purchase 660 MW of replacement power, as well as the cost for the transmission transfer capacity.

SUBSTATION AUTOMATION PROJECT

OPPD has been automating its power system operations and corporate business operations for a long time. Traditionally, departments have automated their own operations, creating islands of automation. Some on-line or off-line sharing of data among automation systems was possible, but this was not the result of preconceived designs. More recently, automation systems have been developed or expanded which are intended to serve several departments, and OPPD determined that an automation plan for all the operations departments needed to be developed.

OPPD has recently initiated the "OPPD Automation Plan" to coordinate and integrate systems District-wide. Implementation of the Plan is in progress and further focus on each system (Energy Management System, Distribution System, Substation Automation, Automated Mapping, etc.) is deemed necessary.

In June 2000, OPPD contracted with KEMA Consulting to assist in developing the automation plan pertaining to electrical substations and to assist in implementing the Substation Automation (SA) Plan at two pilot substations, 912 and 1345. In addition, a Substation Automation Training Simulator (SATS) is being procured that includes one of every type of IED that will be in the SA Systems for 912 and 1345.

Project Charter

OPPD’s primary goal is to develop an integrated approach for implementing SA Systems in a manner that is consistent with OPPD’s SA Project Charter. Key issues in the SA Project Charter include:

- Use of Intelligent Electronic Devices (IEDs) to reduce the number of components required to support protection, control, and data acquisition functions in the substation environment.
- SA System design must be suitable for new substations, but must have sufficient flexibility to allow integration into existing facilities.
- SA protocols and equipment must be scaleable to accommodate Distribution Automation functions.
- Substation safety must be a top priority.

One of the objectives of the Substation Automation (SA) Plan is to integrate maintenance and diagnostic data collected by SA Systems into the Substation Maintenance Management System (SMMS).

Integration Architecture

The implementation of substation integration and automation has three different levels: IED Implementation, IED Integration, and Substation Automation. The first level is simply installing IEDs in the substation. The second level is the integration of the installed IEDs, using the two-way communications capability of the IEDs, via a local area network in the substation. The third level is running applications at the substation level to automate various substation functions. The different levels are shown in Figure 4 below:

Utility Enterprise Connection
Substation Automation Applications
IED Integration Via Data Concentrator/Substation Host Processor
IED Implementation
Power System Equipment (Transformers, Breakers)

Figure 4 – Levels of Substation Integration and Automation

The SA System is a computer-based substation control and monitoring system that will be used to integrate independently operating subsystems, such as SCADA, communications, protective relaying, power apparatus monitoring, control and diagnostics, metering, alarm annunciation, and distribution automation, into a unified data acquisition and control (DAC) system. The SA System will provide the framework to enable existing and future IEDs and conventional electromechanical devices from various suppliers to interoperate, the result being a more efficient and cost-effective monitoring and control system for OPPD's substations.

The implementation of SA Systems at OPPD's pilot substations is being conducted as part of an EPRI TC project. Therefore, the SA Systems should employ to the fullest extent equipment and principles that are consistent with EPRI's Utility Communications Architecture version 2 (UCA2), including:

- Ethernet local area network

- Manufacturing Messaging Specification (MMS) application layer
- GOOSE event objects
- GOMSFE device object models

Approximately 50 IEDs will be installed in Substation 912, which is scheduled for energization in July 2001. A local LAN will be provided by the integrator for handling communications among the IEDs in the substation. All IEDs required by OPPD that support UCA2 MMS will be directly connected (no interface module that is external to the IED is required) to the SA System using UCA2 MMS and Ethernet. For OPPD's IEDs that do not support UCA2 MMS, the integrator will provide appropriate interfaces to translate the different IED protocols to the common LAN protocol for common access services. A data concentrator will be provided for the IED data. A local user interface will be included. The interface to the Energy Management System (EMS) will use OPPD-supplied leased telephone lines. The integration architecture for Substation 912 is shown in Figure 5 below.

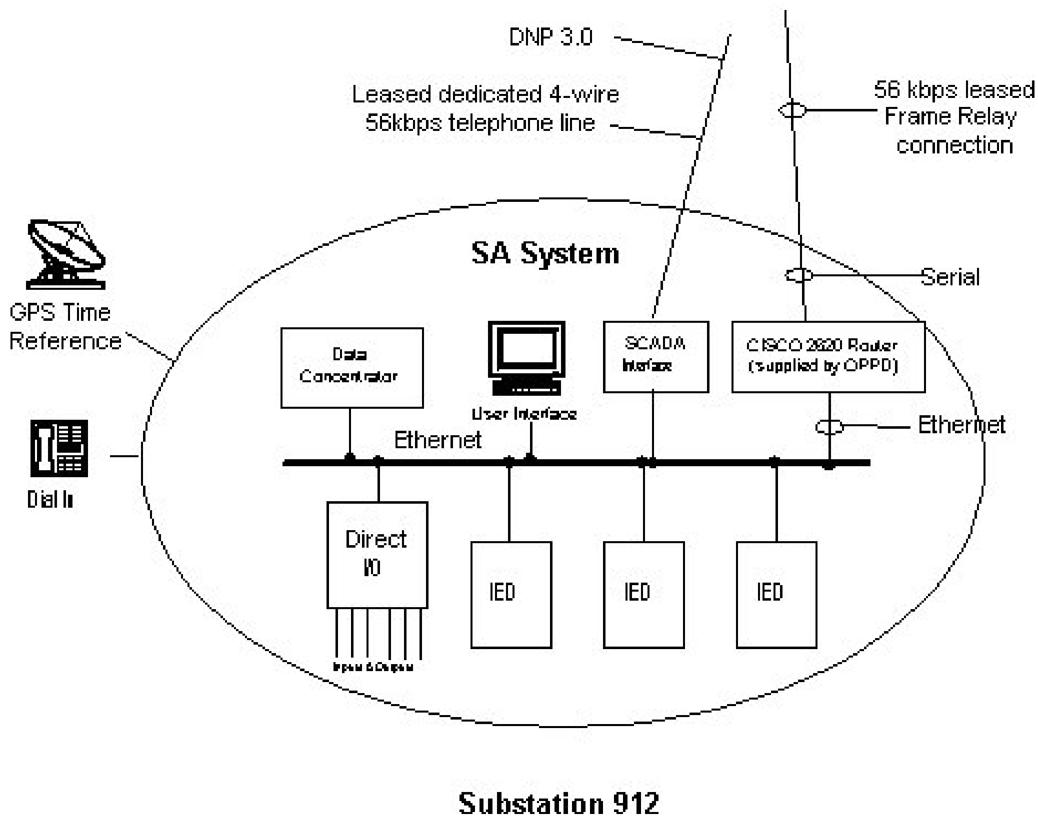

Figure 5 – Substation 912 Integration Architecture

The SA System for Substation 1345, which will be energized in June 2002, will use the same general configuration as the SA System for Substation 912, with the following exceptions. The SA System for Substation 1345 will interface with approximately 25 IEDs. All IEDs required by OPPD that support UCA2 MMS will be directly connected (no interface module that is external to the IED is required) to the Substation 1345 SA System using UCA2 MMS and Ethernet. For OPPD's IEDs that do not support UCA2 MMS, the integrator will provide appropriate interfaces to translate the different IED protocols to the common LAN protocol for common access services. The SA System for Substation 1345 will interface to the EMS via OPPD's optical fiber communication network.

A separate SA System will be provided to enable OPPD to conduct training in a simulated but realistic manner without impacting substation operations. The SATS will also enable OPPD to develop and test new SA System software, including displays, databases, and reports, and modify existing software. The SATS will be a fully operational system that will include all SA System software and all major components of the SA System, including the local user interface, local area network, IED interfaces (as required), EMS and data warehouse interfaces, and other SA System components. The SATS equipment is identical to the system provided for Substation 912, except that the SATS database sizing will be smaller to reflect the smaller number of hardwired I/O and I/O from IEDs. The interface to the EMS and the data warehouse will use the OPPD-supplied fiber communication network. The SATS will accept simulated analog and digital inputs from an OPPD test panel. The test panel will be equipped with test switch isolation as well as current and voltage injection capabilities.

The integration architecture for Substation 1345 and the SATS is shown in Figure 6 below.

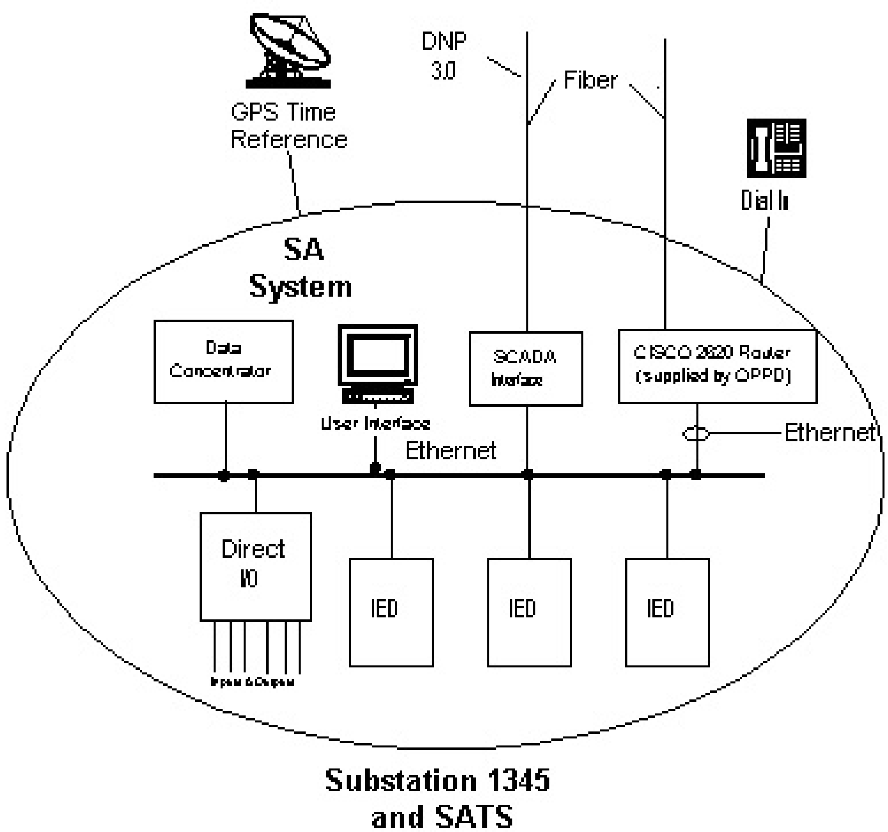

Figure 6 – Substation 1345 and SATS Integration Architecture

Equipment Condition Monitoring at Pilot Installations

ECM devices will be integrated into the SA System architecture. In this way, the data from these devices can be sent to both the EMS SCADA system and the corporate data warehouse. OPPD users will be able to access this data on the corporate network. This sharing of device diagnostic data is not possible now with the dial up connections used to interrogate the devices, and the subsequent storing of retrieved data in various office PCs.

In general, depending on the specific substation, the following ECM devices will be included in the SA System:

- Beckwith LTC Controller, Type M-2001B
- Rochester (RIS) Transformer Alarm Annunciator AN-3196B
- Hathaway Breaker Condition Monitor BCM 200
- Qualitrol Transformer Temperature Monitor TTM 509-100
- Barrington Temperature Differential TDM System 3
- Barrington STAR10000 (timing and velocity)
- Doble On-Line Diagnostics Expert System INSITE
- GE Harley T-MAP 3100
- GE Harley LTC-MAP 2130
- GE Syprotec FARADAY TMMS (transformer monitoring and management system)

The following ECM devices will be integrated in the SA System for Substation 912:

- Four Beckwith LTC Controllers, Type M-2001B (in transformer cabinet)
- Four Rochester (RIS) Transformer Alarm Annunciators AN-3196B (in transformer cabinet)
- Four Qualitrol Transformer Temperature Monitors TTM 509-100 (in transformer cabinet)
- Four GE Harley LTC-MAP 2130 (in transformer cabinet)

The following ECM devices will be integrated in the SA Systems for Substation 1345 and the SATS:

- One Beckwith LTC Controller, Type M-2001B (in transformer cabinet)
- One Rochester (RIS) Transformer Alarm Annunciator AN-3196B (in transformer cabinet)
- One Qualitrol Transformer Temperature Monitor TTM 509-100 (in transformer cabinet)
- One GE Harley LTC-MAP 2130 (in transformer cabinet)

The goal of the project was to interface these devices using UCA2 MMS. However, none of the devices support this interface. The secondary goal was to interface the devices using DNP3. Only the Beckwith and Qualitrol devices support DNP3. The Rochester unit supports Modbus. A separate interface module will be developed, at additional cost, to integrate the GE Harley devices into the SA System architecture.

CONCLUSIONS

ECM IEDs are being implemented by many utilities. In most implementations, the communication link to the IED is via a dial up telephone line. To facilitate integrating these IEDs into the substation architecture, the ECM IEDs must support at least one of today's widely used IED protocols: Modbus, Modbus Plus or DNP3. In addition, a migration path to UCA2 MMS is desired by the utility.

If the ECM IEDs can be integrated into the substation architecture, the operational data will have a path to the EMS or SCADA system, and the non-operational data will have a path to the utility's data warehouse (or equivalent). In this way, the users and systems throughout the utility that need this information will have access to it.

Once the information is brought out of the substation and into the SCADA system and data warehouse, users share the information in the utility. The "private" databases that result in islands of automation will go away.

Therefore, the goal of every utility is to implement ECM IEDs, integrate these IEDs into a standard substation integration architecture, so that both operational and non-operational information from the IEDs can be shared by utility users.

REFERENCES

1. D. Dahlgren and J. Harley, "Implementing a Static Electrification Diagnostic Model", presented at the EPRI Transformer Reliability: Management of Static Electrification in Power Transformers Symposium, Monterey, California, May 1999.