EXISTING SUBSTATION INFORMATION

DRIVES EQUIPMENT LIFE EXTENSION, MODERNIZATION, AND RETROFITTING

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I. INTRODUCTION

Much of the power system equipment in use today is nearing or has passed its predicted operating life, and we are pushing equipment to increasingly higher levels to meet demands. Injuries, failed equipment, unscheduled downtime, and loss of production are concerns that require knowledge of in-service power system apparatus. This is coupled with the competitiveness of the electrical energy market. The prevention of faults and defects in substation primary equipment is considered a major differentiating factor in the quality of power delivered by utilities. The reduction of faults and defects that cause interruptions in the supply of electrical energy significantly improves service performance rates.

The only way to truly know the actual health, performance, and history of apparatus is to observe them in service. Condition-based maintenance and replacement strategies are developed with decision-making information collected from the substation that tells the present state and the history of the primary equipment. It is essential that we enhance, automate, and reduce the cost of collecting and acting on this decision-making information.

To achieve this objective, more efficient and intelligent maintenance practices are required and material, human, and financial resources must be invested correctly. The rules and requirements of the modern market no longer permit numerous corrective maintenance procedures or periodic maintenance practices.

A substation automation system (SAS) is the collection of protection, control, and monitoring (PCM) intelligent electronic devices (IEDs) that comprise a system that monitors, controls, and protects the power system. Innovative PCM IED developments have created new ways of collecting and reacting to data and using these data to create information. When communications to and among the IEDs allow real-time data collection, the SAS is capable of supporting all aspects of electric power protection, automation, control, monitoring, and analysis. Using PCM IEDs as the source of information to understand the health and performance of substation apparatus makes the implementation of a monitoring system economical and technically attractive.
II. ASSET MANAGEMENT PARAMETERS

The concepts of health, availability and reliability, and performance (HARP) are familiar terms within today’s utility. Many companies strive to achieve reduced expenses, 100 percent reliability, increased performance, and, through reliability-centered maintenance practices, better system health. When applied, reliability-centered maintenance practices move the utility from reactive to preventative maintenance and, with better data collection, from preventative to predictive maintenance. Reduced expenses, improved performance, improved reliability, or improved health each individually promises reduced costs and increased customer satisfaction. However, we must not overlook the dynamic and economic impact of one on the other and thereby undercapitalize on short- and long-term profit opportunities.

A. DEFINITION OF HARP TERMS

1) Health
Health is the measure of the fitness of an apparatus to perform its intended function. Apparatus health becomes a variable that can be manipulated to improve return on investment.

2) Availability and Reliability
A failure exists any time that the power system is unable to perform its intended purpose, which is to generate revenue by constantly providing quality power to consumers. Reliability is the measure of the percentage of time (out of the required 24 hours a day, seven days a week) that the power system or apparatus is available to perform its intended function. Reliability is expressed as a percentage of the total possible availability. Using reliability information, we can change procedures and designs to create more available systems and predict the expense of dealing with unscheduled repairs. The knowledge of the availability of apparatus and devices helps prioritize maintenance and replacement schedules to optimize use of resources.

3) Performance
The performance of a system or device is the comparison of its actual operation to ideal operating parameters. Performance is a value that represents the effectiveness of the power system or apparatus in service. Effectiveness can also be manipulated to improve revenue, customer satisfaction, and, eventually, return on investment. Actual performance is expressed as a percentage of optimal performance.

4) Net Installed Value
Net installed value (NIV) is the present value of an in-service asset. NIV is the aggregate of expenses and the HARP variables. Actual NIV is expressed as a percentage of the optimal NIV. Predicted NIV is a prediction of the result of manipulating the HARP variables and understanding their effect on one another.

5) Net Revenue
Net revenue (NR) is defined as the total customer billings minus annual expenses (scheduled and unscheduled). Future considerations related to net revenue include intangible costs, such as cost to customer, customer satisfaction, and litigation. Many utilities have not calculated these intangible costs, but those that do can factor them in.

6) Net Potential Revenue
Net potential revenue (NPR) is the sum of the following variables:
- Unserved is the loss in profit because of an outage and/or real load that could be served if a breaker, transformer, or wire is under capacity.
- Growth is future or planned unused capacity. It might be more cost-effective in the long term to invest in new equipment or overload existing equipment than to minimize cost and underserve present and future demand.
- Reduced operations and maintenance cost is the potential to reduce costs (thereby increasing revenue) through life extension of apparatus and targeted replacement of obsolete and poorly performing equipment with newer, more efficient equipment or through modified maintenance practices. Typically, operations and maintenance costs are predicted, but with real-time and historical operating data, these costs are measured and dramatically improved.

Looking at the overall HARP NIV for an existing breaker versus the HARP NIV of a new breaker with the fiscal economic backdrop of net revenue and net potential revenue, the result of the evaluation might be:

\[ \text{NIV existing breaker} + [\text{NPR} - \text{NR}] < \text{NIV new breaker} + [\text{NPR} - \text{NR}] \]

In order to enhance the performance of existing systems and new designs, electric utilities must fully understand the current state of the power system as well as predict future capabilities and system expansion to increase reliability and performance.
Increased global competition, deregulation, availability demands, and pricing pressures are forcing the electric utility industry to reduce operation costs while increasing reliability. Utilities often need to push equipment to higher loading levels to meet demands.

B. PCM IED MONITORING FUNCTIONS
The IEDs used in the digitalization of distribution substations include protection, automation, control, and communications functionalities. They also collect and create important analytical data by monitoring the devices and the surroundings that the IEDs protect. This information is used to calculate the HARP variables.

Each main device of a substation has at least one associated IED receiving voltage, current, status, and other signals that are used to make precise diagnoses in real time. Because IEDs are connected to the dc system of a substation, they also provide important information for the monitoring and diagnosis of the substation dc battery system.

In this way, the information available in an IED is used to monitor disconnect switches, power transformers, dc battery systems, and circuit breakers.

The maintenance of circuit breakers, for example, is usually based on regular time intervals or the number of operations performed. The methods based on this philosophy present drawbacks because within the predetermined maintenance interval, there could be an abnormal number of operations or a small number of operations with high-level currents.

**The IEDs monitor the following:**

**Contact Wear**
The circuit breaker manufacturer provides a maintenance curve listing the number of close-to-open operations and the interruption current levels. The function of this curve is to predict the breaker contact wear, as the example shows in Figure 1. It is possible to configure some of the points of this curve, where normally the highest and lowest number of operations and an average point are chosen. For each operation, the IED integrates the interrupted current with the operation number to update the contact wear value. This parameter is crucial to estimate the need for maintenance.

**Total Number of Operations**
Incremental counters for close-to-open operations are implemented to make that information available to the system history.

**Mechanical Operating Time**
The mechanical operating time of the circuit breaker can be calculated by measuring the time interval between the trip command or the close command and the asserting of the digital inputs of the IED connected to the circuit breaker status contacts. Deviations in this value may indicate problems in the drive mechanism.

**Electrical Operating Time**
Similar to the mechanical operating time, this measures the time interval between the trip or the close command and the clearing or normalization of current measurements in the circuit breaker. If this parameter tends to increase over time, it could indicate failures in the contacts.

**Inactivity Time**
By monitoring the activity of the number of operations, it is possible to calculate the number of days in which the breaker has been inactive. Long periods of inactivity degrade its reliability for the protection system.

**Spring-Loading Time**
Just after the circuit breaker closes, the time to assert the digital inputs of the IED connected to the breaker loaded spring contact is measured. If this time increases as the number of operations increases, it may predict a problem in the spring-loading mechanism.

**Figure 1: Circuit breaker maintenance curve**
The monitoring functions presented here are performed with traditional protection potential transformers (PTs) and current transformers (CTs). No additional stand-alone sensor is necessary for the equipment monitoring system, as shown in the basic connection diagram in Figure 2.
Figure 2: Basic connection diagram for monitoring of circuit breakers
An example of the knowledge of the health and performance of a breaker, calculated by a PCM IED and documented as a breaker monitoring report retrieved from that IED, is shown in Figure 3.

Figure 3: Breaker monitoring report

III. ADD SUBSTATION MONITORING TO YOUR SUBSTATION AUTOMATION SYSTEM

Investments in substation monitoring systems are essential for creating reliable predictive maintenance; however, stand-alone systems are complicated and expensive and are only viable for large substations, even though they are becoming essential for smaller distribution substations.

A substation monitoring system (SMS) can use the information supplied by IEDs and take advantage of communications network structures already in place or provided for the substation SAS. The same IEDs used for command, measurement, protection, and control form the basis of the system. They are more rugged and dependable than other monitoring devices such as sensors or programmable logic controllers. They create information and send it to the maintenance server which in turn performs calculations and feeds the database. These functions are executed because the IEDs are coupled with the main equipment via CTs, PTs, resistance temperature detectors, and so on.

Using an in-service SAS system enables the building of an economically viable SMS that is developed by using the network structure and data provided while maintaining the same reliability, regardless of the size of the facility. Figure 4 illustrates the basic structure for an SMS as part of the SAS.

Figure 4: Basic data structure of SMS
A variety of communications ports and protocols allows a broad application of hardware and easy integration with any communications system existing in the substation. Fig. 5 shows the local maintenance server containing the integrated SMS without any change in the communications network.
IV. ESSENTIAL INFORMATION TO CHOOSE LIFE EXTENSION OR REPLACEMENT

Consider the typical substation illustrated in the one-line diagram shown in Fig. 6.

Figure 5: Example of SMS integrated in the substation

The engineers and those responsible for the maintenance of this equipment access the information locally on the maintenance server or remotely through the web via intranet or Internet. Considering the access through the maintenance center, the installation of additional software is not necessary because the SMS is created independently of the operational system. A modern SMS uses Ethernet network communications and is in compliance with the IEC 61850 standard. It also adapts to substations that are not in compliance with the standard because of the flexibility and multiprotocol structure existing in the system.

Figure 6. One-line diagram of typical substation
FEATURE

The monitored health and performance parameters necessary to decide between life extension or replacement of the power system equipment from Figure 6 are shown in Table I.

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<tr>
<th>Tag</th>
<th>Equipment</th>
<th>Monitoring</th>
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<tbody>
<tr>
<td>CB-E1</td>
<td>Incoming circuit breaker</td>
<td>Number of operations</td>
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<td></td>
<td></td>
<td>Mechanical operating time</td>
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<td></td>
<td></td>
<td>Spring-loading time</td>
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<tr>
<td></td>
<td></td>
<td>Circuit breaker contact wear</td>
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<tr>
<td>DS-T1</td>
<td>Disconnect switch</td>
<td>Number of operations</td>
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<td>Position discrepancy</td>
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<td></td>
<td>Motor power</td>
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<tr>
<td>CB-T1</td>
<td>Transformer high-voltage circuit breaker</td>
<td>Number of operations</td>
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<td></td>
<td></td>
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<td>Spring-loading time</td>
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<td>Circuit breaker contact wear</td>
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<tr>
<td>TR1</td>
<td>Power transformer</td>
<td>Transformer temperature</td>
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<td></td>
<td></td>
<td>Efficiency of forced ventilation</td>
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<td>Insulation aging acceleration factor</td>
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<td>Estimated insulation service life</td>
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<tr>
<td>CB-A1</td>
<td>Feeder circuit breaker</td>
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<td>Spring-loading time</td>
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<tr>
<td></td>
<td></td>
<td>Circuit breaker contact wear</td>
</tr>
<tr>
<td>SA-S1</td>
<td>Substation auxiliary service</td>
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<td></td>
<td></td>
<td>Voltage Vdc (−)</td>
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<td></td>
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<td>Vdc voltage level</td>
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<td></td>
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<td>Detection of leakage current to ground</td>
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<td>AC ripple in the rectifier</td>
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CONCLUSIONS

Monitoring systems are essential tools that allow distribution companies to increasingly modernize maintenance techniques and migrate to intelligent and optimized predictive maintenance. Investments that are made in the acquisition of substation equipment monitoring systems add additional costs to maintenance and operation, so the minimization of these costs is a huge challenge.

The SMS is a low-cost solution for the implementation of communications infrastructure in substations using IEC 61850 protocols, where Ethernet cabling already exists, enabling its application in substations of any size and voltage level.

A cost analysis shows that the investment to add an SMS to an SAS network to modernize maintenance practices amounts to a small incremental cost of 10 to 15 percent of the initial cost of digitalization of a small distribution substation. For a larger and more complex substation, the investment to implement the SMS is an even smaller incremental cost.

Adding the SMS technology to an in-service SAS system is an incrementally small investment that provides a wealth of information about the power system. When used to calculate HARP variables, this information enables informed decisions about life extension or replacement of in-service primary equipment.
V. REFERENCES


David Dolezilek received his BSEE from Montana State University and is the technology director of Schweitzer Engineering Laboratories, Inc. He has experience in electric power protection, integration, automation, communications, control, SCADA, and EMS. He has authored numerous technical papers and continues to research innovative technology affecting the industry. David is a patented inventor and participates in numerous working groups and technical committees. He is a member of the IEEE, the IEEE Reliability Society, CIGRE Working Group, and two International Electrotechnical Commission (IEC) technical committees tasked with global standardization and security of communications networks and systems in substations.

Geraldo Rocha received his BSEE from Universidade Estadual Paulista Campus de Ribeirão Preto, Brazil, in 2001, and specialized in electrical power system protection at Universidade Federal do Rio de Janeiro. He worked as a protection and automation engineer for CPFL Gerência de Energia S.A., where his responsibilities included maintenance, commissioning, specification, and studies of protection and automation of hydroelectric plants. In 2007, he joined Schweitzer Engineering Laboratories, Inc. as an application engineer covering the entire country of Brazil. His responsibilities include training and assisting customers in substation protection and automation efforts related to generation, transmission, and distribution areas.