Lessons Learned from Substation Predictive Maintenance Project TC Project #7014

TR-111594

Final Report, December 1998

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REPORT SUMMARY

A tailored collaboration conducted between 1993 and 1998 by EPRI and ten participating utilities aimed at optimizing substation performance through predictive maintenance. This report summarizes the lessons learned from the project: a more comprehensive report will be published after further research.

Background

This research project grew from serious utility concerns over transformer failures, the high costs of circuit breaker Preventive Maintenance (PM), and loss of off-site power at nuclear facilities. PECO Energy initiated the project as part of a plan to enhance their existing PM program. Success with predictive and condition monitoring programs at the Eddystone Plant, including $5M in cost savings for the year 1991, led to a pilot Substation/Switchyard Predictive Maintenance program (SPDM) in which the EPRI Monitoring and Diagnostic Center (M & D Center) evaluated diagnostic equipment and techniques, built the data acquisition process, and developed rules and procedures for analysis. Within two years, the SPDM program achieved $2M of documented avoided costs and additional utilities joined the project as its focus turned toward bringing the PM process to transmission and delivery organizations at-large. Ten companies have participated in the program to date: Central Power & Light, Duke Power, Duquesne, Light Company Omaha Public Power District, PECO Energy, Potomac Electric Power Company, San Diego Gas & Electric, South Carolina Electric & Gas, Tennessee Valley Authority, and Wisconsin Power & Light.

Objective

To reduce O&M costs by performing condition-based surveys on energized substation/switchyard equipment; to develop and assess new technologies, procedures, and training methods for protective maintenance programs.

Approach

The project team performed substation/switchyard equipment condition surveys and formulated procedures and guidelines at participating utilities. They selected the equipment to monitor, the technologies to monitor that equipment, and the appropriate intervals for collection of condition data. Each participating utility conducted at least 9 substation condition surveys over a three-year period; many conducted substantially more. Each organization provided information and test result data for specific types of

equipment and wrote test procedures reflecting local conditions. The M&D Center provided classroom training and on-the-job field training for engineering and field technical personnel in substation condition survey techniques utilizing ultrasonic noise analysis, portable gas-in-oil analysis, infrared thermograph, visual inspection, vibration analysis, and sound level testing. The team developed criteria for evaluating the severity of conditions and guidelines for monitoring techniques to corroborate detected abnormalities.

Results

This project developed and implemented an effective predictive maintenance strategy for substation/switchyard equipment. Existing and new technology applications were evaluated and adapted for condition monitoring of energized substation equipment. The SPDM process was effective in reducing O&M/Capitol costs, increasing equipment availability/reliability, and moving the culture of participating organizations to a more proactive approach. All participating organizations are currently using the specific survey methods, procedures, and processes developed in the project. Benefits in avoided costs for the project years are conservatively estimated at $15M. Other cost benefits, though not documented in the report, include savings from the reduction or elimination of PM tasks, enhanced equipment reliability, availability improvements, and a longer job-planning horizon. Several findings with industry-wide implications emerged from the project: a safe way to eliminate time based maintenance for high voltage transformer load tap changers, the identification of a novel problem with oil contamination from sample ports, and important insights into the preventive maintenance of generator step up transformers.

EPRI Perspective

EPRI and the EPRI M&D Center are dedicated to improving operations and maintenance processes and procedures to reduce maintenance costs, improve equipment reliability/availability, and avoid unscheduled outages. This phase of the SPDM program, which focuses on determining equipment maintenance tasks from equipment condition data, has contributed a great deal to these goals. Substation predictive maintenance processes have proven to be a valuable tool in detecting impending equipment failures and in prescribing lower cost and more effective maintenance tasks.

TR-111594

Interest Categories

Substation operations and maintenance

Keywords

Substation Maintenance	Predictive Maintenance
Diagnostic Monitoring	Reliability/Availability
Performance	Condition Monitoring

ABSTRACT

The EPRI Maintenance and Diagnostics Center, through a tailored collaboration effort with ten (10) utilities, developed a Substation Predictive Maintenance Program (SPDM). The objective of the program was to reduce Operation and Maintenance (O&M) costs by applying predictive/condition based maintenance practices to energized substation equipment. This report presents a summary of the project including: how new and existing diagnostic technologies and equipment were evaluated and utilized; how information was gathered on program cost justification and savings and specific work procedures and program administrative aids for a SPDM process. The program was effective in implementing a preventive or condition based maintenance process for participating utilities—enhancing the prioritization or work, redirecting maintenance activity and reducing costs. This document can serve as an implementation guide with lessons learned for substation predictive maintenance processes or to compare and contrast programs currently in place.

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INTRODUCTION AND OVERVIEW

For many Power Delivery/T&D organizations, the present choice of maintenance strategy is based on a combination of time based preventative maintenance and failure based (corrective) maintenance tasks—with time and/or usage of equipment as the trigger or initiators of preventative maintenance activity. This approach is most always augmented by the use of some degree of technology for determining equipment condition—visual and thermographic inspections, testing of transformer oil, on-line alarm indications and power factor testing being the most widely utilized. Many have computerized maintenance work histories, design information and logs of operational activities as additional aids to maintenance decision making. However, few utilities have integrated such information with periodically-acquired data in a comprehensive conditioned based maintenance program for substation equipment. By applying the type of conditioned based maintenance practices widely utilized in power plants to substation and switchyards, reduced O&M/Capital costs and increased equipment reliability and availability are possible.

SPDM incorporates standard tenants of Reliability Centered Maintenance programs (RCM). The process utilizes techniques of identifying and preserving system and component functions through understanding of performance degradation and failure modes and determination of failure defense activities. This information is combined with the technical experience of personnel and tracking and trending of equipment condition data to guide decision making toward the optimum maintenance plan. A maintenance plan that is "living" in that it will continuously change—undergoing continuous refinement and adapting to changing equipment and conditions. The goal of a SPDM process is to determine the proper mix of maintenance activities (Corrective, Preventive, Predictive/Condition based and Proactive) that obtains least cost and highest performance of equipment (including life extension). Definitions for different types of maintenance strategies/decisions, as typically defined in a Maintenance Optimization program and utilized as part of the SPDM process are as follows:

Reactive/Corrective—maintenance activity based upon a decision to perform no preventive or predictive activity(s) in order to allow equipment to run to failure prior to repairing or replacing it.

Preventive—performing maintenance activity based upon calendar time and/or some measure of use/operation of the equipment. A decision to invest resources in anticipation of deterring damage or failure of the equipment based upon experience of a time/use and equipment performance correlation.

Predictive—maintenance activity based upon information indicating condition of the equipment—data showing nominal or degraded performance or symptoms that correlate with degraded performance or failure of the equipment.

Proactive—activity undertaken to eliminate or minimize the need for predictive, preventive or corrective maintenance based upon changes to equipment operating practices, design or application and understanding of other factors affecting equipment performance.

The SPDM as piloted in the TC effort can be characterized as consisting of three components: regularly scheduled on-site substation evaluations, equipment monitoring and diagnostics, and a management group or focus to coordinate the program. On-site evaluations consisted of regularly scheduled visits (two or three times per year) by a group of trained maintenance & test specialists. This group was outfitted with an array of technologies used to evaluate equipment condition:

- Vibration Analysis
- Ultrasonic noise analysis/Partial Discharge Detection
- Portable Gas In Oil Analysis
- Infrared Thermography
- Sound Level Testing
- Visual Inspection (with optical aids)

During the EPRI SPDM collaboration, M&D Center personnel performed three site visits to each utility per year to agreed upon substation locations and used their own diagnostic tools to evaluate equipment. Equipment evaluated included transformers, circuit breakers, disconnect and ground switches, bus structure, capacitor banks, insulators, cooling equipment, battery banks and most all equipment residing in the control house. As the equipment was surveyed, baseline condition data was recorded on a data collection sheet and any anomalies were recorded for a summary report on the substation. Utility personnel received both classroom and hands-on training from EPRI personnel on the technologies and methods for the condition surveys. Appendix A contains technology specific procedures developed for collecting condition data on substation equipment. Appendix B provides a general guideline used for collecting data in substation/switchyards.

In addition to applying the above stated technologies, the following data from testing and on-line monitoring was used for analysis of equipment condition:

- Oil Quality and Dissolved Gas Analysis Data
- Power Factor Test Results
- Equipment Maintenance History
- Circuit Breaker Response Data
- On-line data:
  - Transformer Tap Changer Monitors
  - SF6 Monitoring
  - Circuit breaker I2T Monitoring
  - Gas-In-Oil Monitoring

SPDM Process Description

In a strictly time and/or failure based maintenance strategy, information on equipment condition is looked at primarily in retrospect to add to an explanation of failure or to aid in estimating the periodicity for time based maintenance decisions. The objective in adopting a predictive and condition based maintenance strategy is to determining the optimum mix of maintenance activities that produce lowest cost and highest performance. This includes the choice of running low cost, low importance equipment to failure. The sources of information and coordination required to continuously streamline maintenance activities toward the optimum mix are depicted in Figure 1-1.

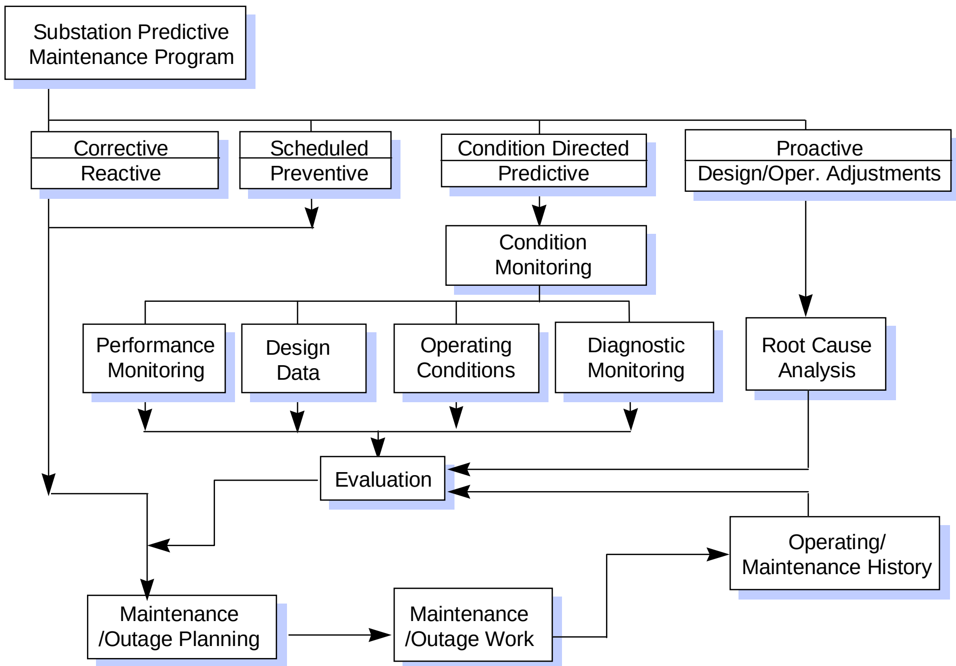


Figure 1-1
SPDM Process Description

Determining the optimum mix requires that large amounts of data on the condition and history of equipment be managed. This required a new, more formal understanding of the work processes required to accomplish this. The core data management process can be characterized as having three (3) macro process steps—collection of data, deriving information from data and taking corrective action from the information. Figure 1-2 illustrates the process steps.

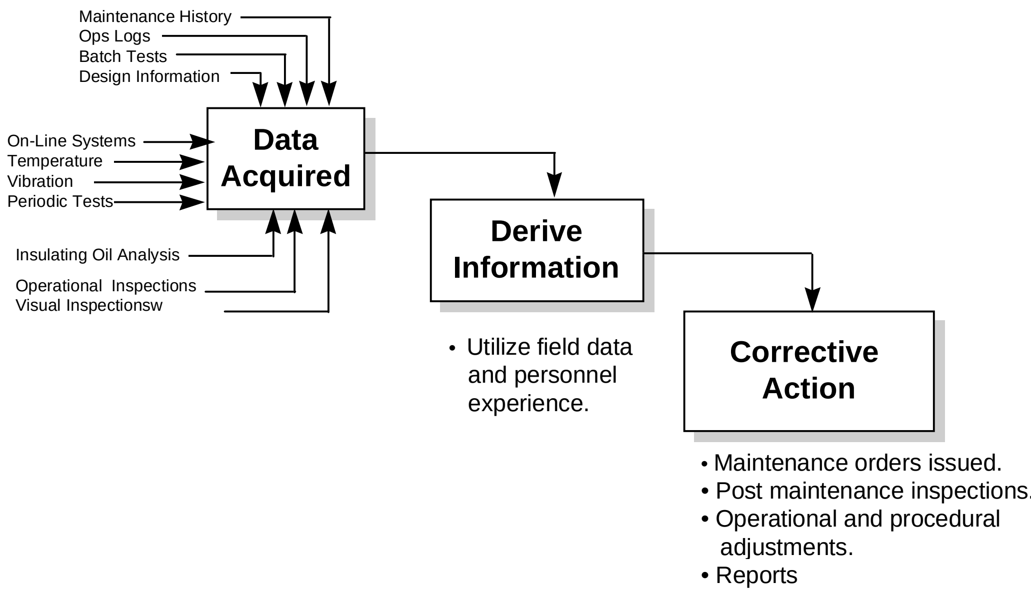


Figure 1-2
Data Management Process

As represented in Figure 1-2 many sources of data are available to derive information on equipment condition. Turning data into information on the condition of equipment and ultimately into actionable tasks is accomplished in several ways:

1. Comparison of a predictive maintenance variable to an absolute known limit. Example: Tap changer to main tank temperature differential shall not exceed 10 degrees Celsius.

2. Comparison of data for two or more identical components in a similar operating mode and environment. Example: 1A vs. 1B transformer.

3. Standard practice—limits based on previous lessons learned will sometimes be employed. Example: Transformer temperatures shall not exceed a 65 degree Celsius rise.

4. Co-incident indication of two or more condition monitoring or performance parameters. Example: Tap changer indicates a positive temperature differential. DGA results indicate hot metal gasses.

5. Rate of change at which predictive maintenance parameter changes can give an indication of a developing failure. Example: Trend shows significant increase in a particular gas that could still be lower than a preset threshold. Increase monitoring until the situation stabilizes.

6. Statistical analysis can be used to set repair priorities when no prior information is available. This approach is especially effective when data from a large number of like equipment is available.

As field crews collected condition data during substation surveys the results were documented per procedures on data collection forms. These forms are shown in Appendix B as Field Data Acquisition and General Database forms. Crews collecting condition data and reporting anomalies also need a method to evaluate their findings against multi-technology severity criteria in order for the information to be useful to others in the organization. Appendix B shows a sample report including severity criteria and action levels used during the program. This periodic summary report, encapsulating information on substation surveys is produced in order to document results and communicate with management at a summary level. These documents were adapted to each organization in order to fit with terms, definitions and understanding already established as part of the maintenance program. Also, it should be noted that severity criteria for infrared thermography is equipment specific.

2

REVIEW OF PREDICTIVE TECHNOLOGY/THEORY AND APPLICATIONS

Several technologies and methods of using technologies are currently in the early stages of evaluation and testing and are not included in discussion. The areas are:

- on-line equipment monitoring units for circuit breakers and transformers.
- evaluating correlations in vibration data gathered before and after re-clamping/tightening of transformer intervals.
- on-line gas-in-oil monitoring equipment.
- field testing and evaluation of portable Dissolved Gas Analysis equipment.
- evaluating oil for Furanic compounds to determine paper degradation.

As a summary to this section; a spreadsheet showing the value of diagnostic technologies as applied to different energized equipment types is included in Appendix A entitled—Diagnostic Technologies Equipment Applications Matrix.

Vibration Analysis

Vibration analysis was included as a diagnostic technique in the Substation Predictive Maintenance (SPDM) Program to determine its value in making decisions on the condition of energized electrical equipment. Data collected during the project has shown that taking external vibration readings on a transformer carrying load, to “baseline” its condition, provides trendable data and the knowledge to make determinations regarding changing winding conditions.

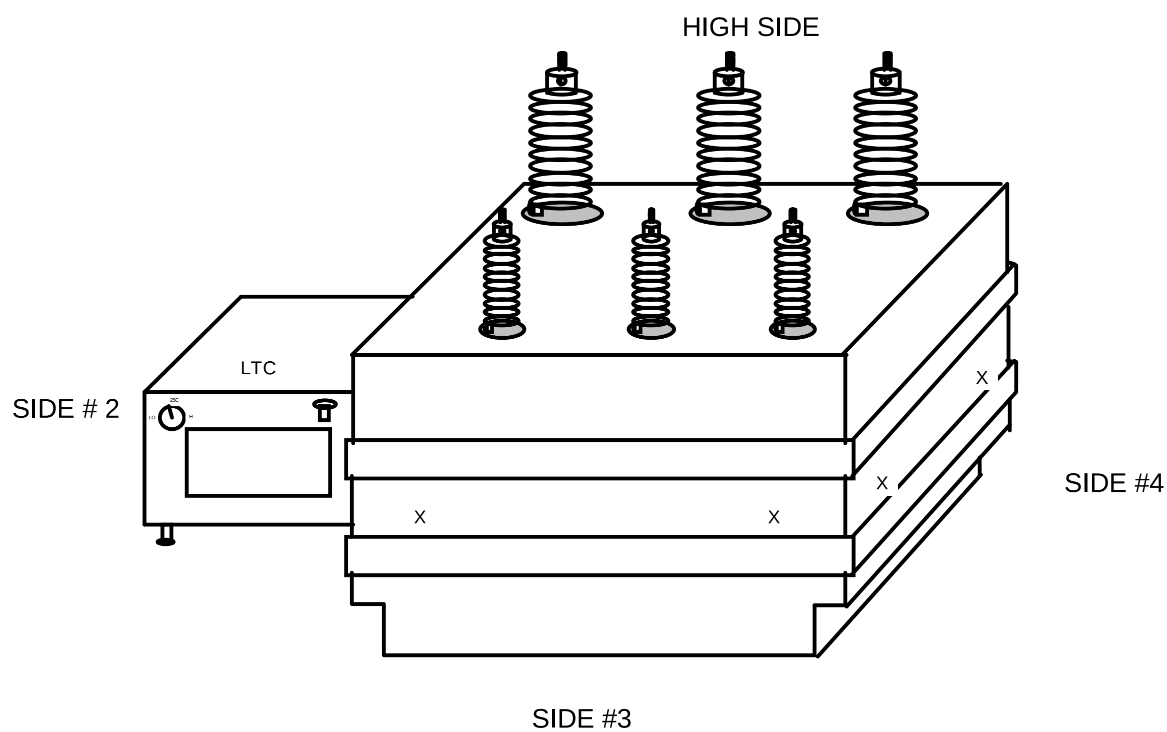
Applications

Transformers, Pumps, Vertical Piping,

Data Acquisition and Locations(Transformers)

Data is acquired starting on the left facing the high voltage side(side #1 or high side), then continuing counter clockwise around the equipment. All data and equipment locations should be identified in the following manner:

Data Locations: Side1L, 1R; Side2L, 2R; Side3L, 3R, and Side4L, 4R as shown in figure 2-1 below.

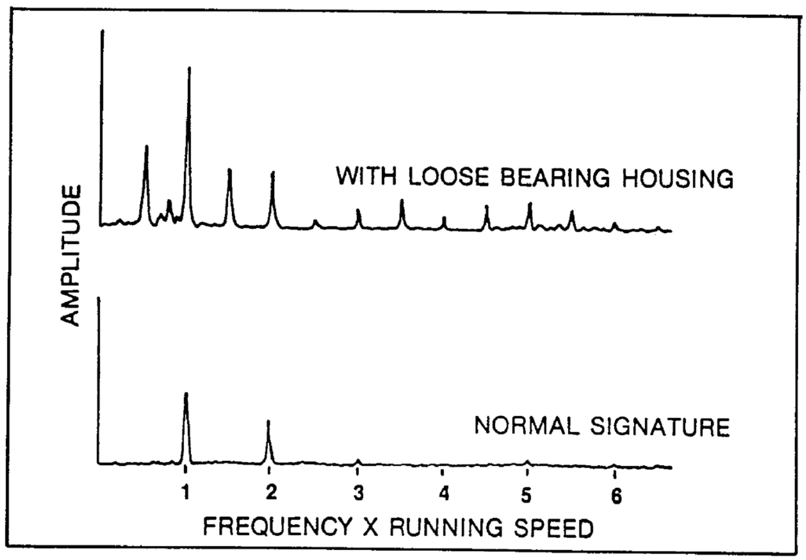


Take the readings on the corners at approximately the 5 foot elevation, 18 inches from the corner.

Figure 2-1
Vibration data locations

Data Analysis

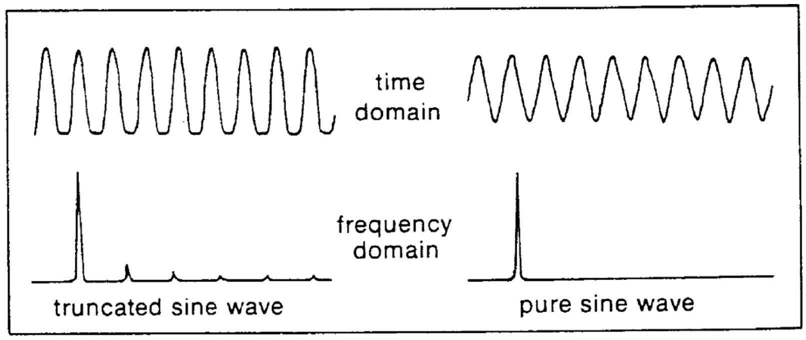
Information revealed in the spectrum indicates that harmonics of 2X line frequency (120 Hz), can be acceptable. Multiples of 2X that are present (240 Hz, 360 Hz) are usually at levels lower than 2X, and usually do appear in the vibration spectrum. Amplitudes at odd frequencies (60, 180, 300, 420 Hz) should be close to zero. The data presented in Figure 2-1A & B is from a motor, but is used here to demonstrate the effect of mechanical looseness in both a spectrum and waveform presentations.



Spectral characteristics of mechanical looseness.

Figure 2-1A
Spectrum

Mechanical looseness, the improper fit between component parts, is generally characterized by a long string of harmonics of running frequency at abnormally high amplitudes. Although the exact method by which the harmonics are generated is not well understood, they are probably originated by the nonlinear response of the loose part to a dynamic input from the rotor. This type of phenomenon has been observed on machines where the bearing liner was loose in its cap. Thus, one can safely conclude that, regardless of their exact origin, a string of relatively high amplitude harmonics is clearly abnormal.



A truncated waveform generates harmonics.

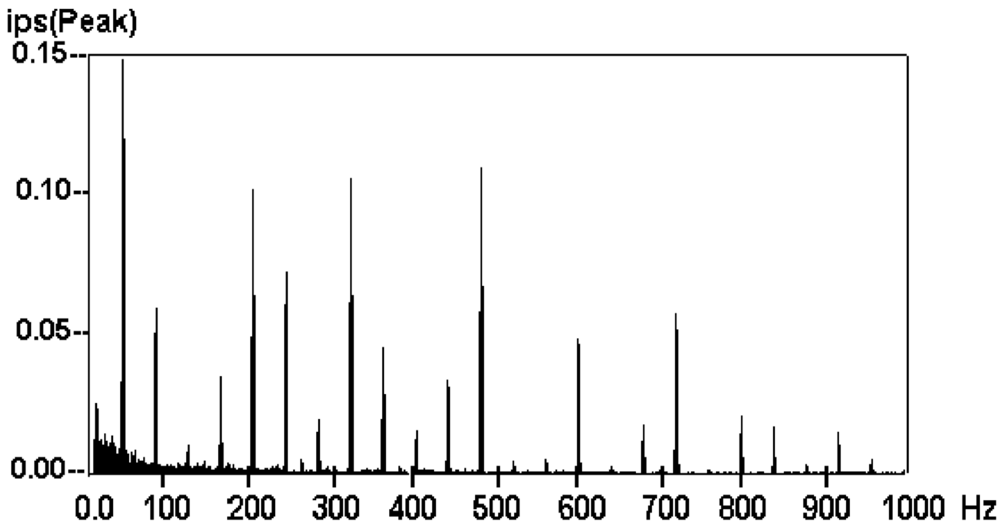
Figure 2-1B
Waveform—reference: *Machinery Analysis & Monitoring*, John S. Mitchell

Baseline signatures are especially important on transformers or two reasons; first to document the transformer's existing or original condition, and second to assist in determining what maintenance needs to be performed, if any, after an upset . With age, faults on the lines, and the eventual deterioration of the insulation and clamping, the spectral energy moving from the core to the transformer shell, will change and can be easily detected.

Figure 2-2 is an example of a vibration spectrum from a transformer that was recommended for inspection, and one that requires no action. Using 'loose,' 'marginal' and 'tight' as the severity criteria, T1 transformer was considered loose and T2 tight. The information in the T2 spectrum is at the expected frequencies (120, 240, 360 Hz).

Note: Only transformers considered 'loose', would be recommended for an internal inspection.

T1 (Recommend For Inspection)
Westinghouse 594MVA (1951)



T2 (No Action Required)
GE 85MVA (1953)

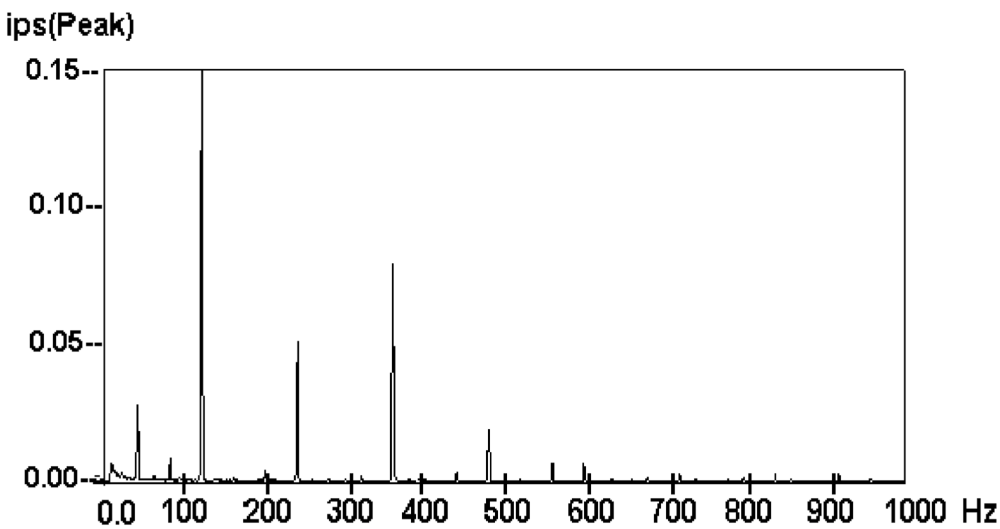


Figure 2-2
Transformer Recommendations (T1-Inspect and T2-OK)

Figure 2-3 is an example of data from a new transformer with very low vibration levels and, a transformer scheduled for replacement and thought to be in bad condition internally. The utility thought that the old transformer had loose blocking and possibly deformed windings. The transformer was closely inspected after removal and was found to be in good condition

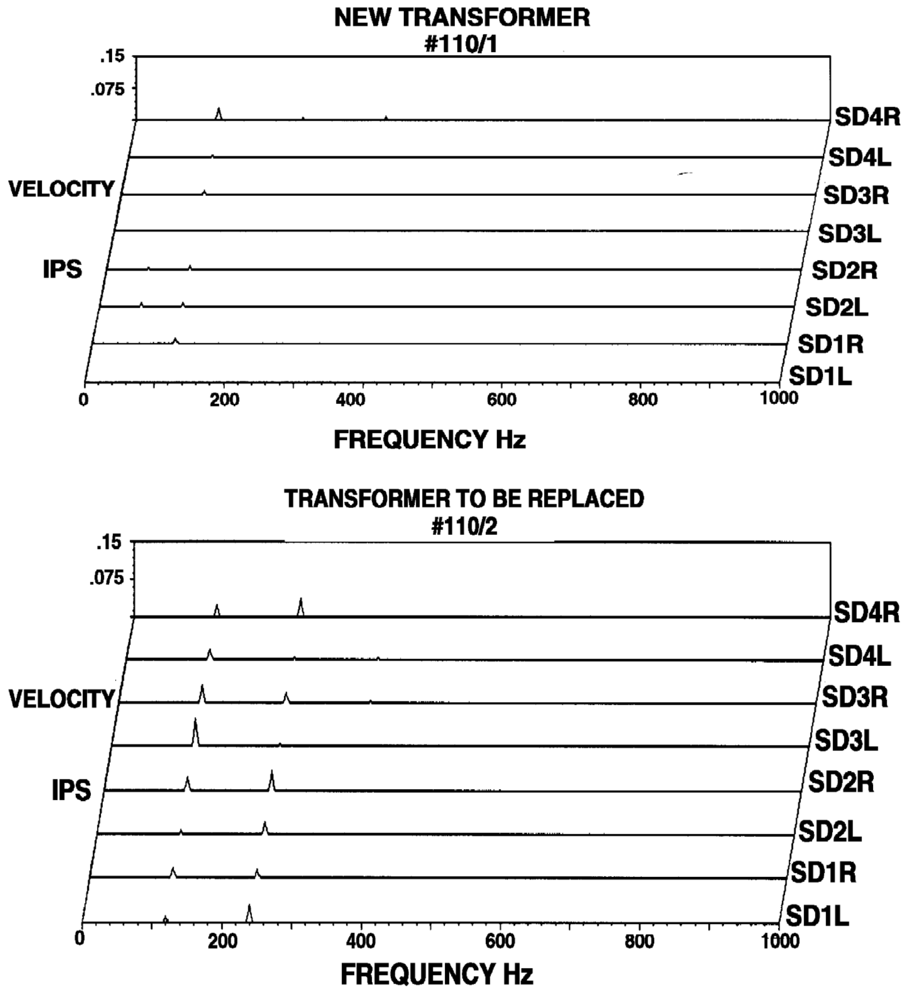


Figure 2-3
Vibration Data: (New Baseline) & Old Inspected

Note: Although this transformer was removed from service and factory inspected, nothing was detected from the periodic survey data or DGA history to substantiate this action. An evolving diagnostic technique needs some "case histories" prior to being widely accepted as a viable tool or test method. Using vibration analysis, should be only a part of a decision making process.

Complimentary Technology

Oil Analysis, Ultrasonic Noise, and Sound Level

When vibration patterns are considered abnormal, other diagnostic techniques should be used to confirm overall condition. In the oil, hot metal gasses may begin to rise, Ultrasonic noise from continuous low level partial discharge activity may be detected, and as the windings loosen or become deformed, audible sound levels will increase.

Spectral Analysis Vs Overall Levels

Spectral analysis is required because overall vibration levels only indicate a vibration level, not the frequency or frequency's causing the level. Example: 0.5 ips is recorded on a transformer wall with an vibration meter. That overall answer is all that is known and is not very helpful. When the same reading is taken with a spectrum analyzer, information in the spectral plot lets the analyst know if the cause of the reading is expected, or possibly generated by an anomaly.

Sonic/Ultrasonic Noise Analysis/Partial Discharge Detection

Technology

Partial discharge is an electrical phenomenon that occurs whenever the voltage value is sufficient to produce ionization, which partially bridges the insulation between conductors. The electrical insulating properties of materials are degraded under the influence of partial discharges and can lead to eventual failure and even catastrophic loss of equipment. In most cases, the discharges start well before the insulation fails. Early detection of partial discharges effectively reduces the possibility of transformer failure. Acoustic emission (AE) testing is a common practice for in-service inspection of petrochemical vessels and high energy piping. Now AE techniques are being applied to the inspection of oil filled transformers. By listening to a transformer using a high frequency fault detector, it is now possible to accurately detect partial discharge and determine the location within the transformer. The acoustic emission emanating from the partial discharge sources within a power transformer produce a burst type signal with a characteristic frequency of 150 kHz . The energy contained within each burst is determined by counting the number of these oscillations occurring within a 1 second interval that exceed a preset threshold within that time, as well as the peak amplitude. The amplitude of the stress wave at the various monitored points is affected by the attenuation of the signal as it passes through the oil of the transformer on route to the tank wall. Using peak amplitudes and event counts from these signals is the method used to determine the approximate location of a partial discharge source as well as determining its severity. The use of a portable acoustic detection device, the 5550 fault detector, gives the operator the ability to listen to, and document(baseline) the high frequency activity from the acoustic signals within the transformer. Internal transformer problems can be detected, the source of activity located, and the problem repaired during entry. The high ambient electrical and mechanical noise levels present within the substation environment are not a problem and PD signals can readily be differentiated from other signals emanating from the transformer. Two frequency ranges are used when "Listening " on the Transformer wall, sonic which is all frequencies up to 20khz and ultrasonic, all frequencies from 20Khz to 250Khz. When a transformer is in good condition the hum coming from line frequency with no "popping" or "buzzing"will be detected (heard), especially in the low frequency range. When discharges occur, the "popping" or "bacon frying" sound can be heard in both the sonic and ultrasonic bands. The fault detector is used to locate the source of activity. When non periodic random events are heard, oil needs to be laboratory analysed to determine what gasses are present and at what levels.

Applications

Oil Filled Equipment—Transformers, LTC's, Reactors, Circuit Breakers.

Metal Clad Switchgear

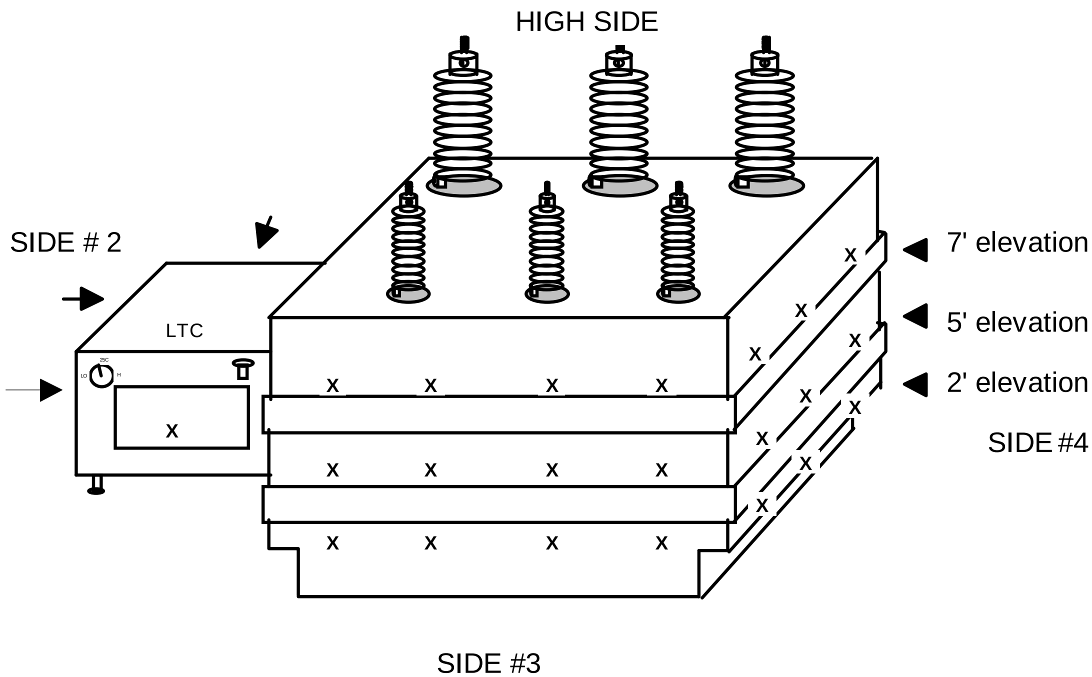
Gas Filled Circuit Breakers and Buswork

Bushings, Lightning Arrestors, Insulators, PT's and CT's

All Other Energized Equipment

Data Acquisition and Locations for Transformers

Data is acquired starting on the left facing the high voltage side(side #1 or high side), then continuing counter clockwise around the equipment. All data and equipment locations should be identified in the following manner. Example: Use Figure 2-4 below. A transformer has two pumps and a load tap changer(LTC). One pump is on the high side, the other on the opposite side. The pumps would be side1-pump1 and side3-pump2, the LTC would be side2-LTC1



Take readings at three elevations and no more than six feet apart horizontally.

Figure 2-4
Data Acquisition Locations

Data Analysis

Data is acquired at locations no more than six feet apart, closer when oil is reported to have acetylene. High frequency noise attenuates rapidly, and most times is barely detectable. Using six feet as a guide, allows for a surface wall detection distance of three feet.

Complimentary Technology

Oil , Vibration, and Airborne Ultrasonics

Source Location

This diagnostic technique is used to assist in determining the severity and location of partial discharges. Analysis of noise on transformer walls, vibration analysis on all rotating equipment and leak detection on pressurized vessels. Wave shape analysis can be used to detect flow restrictions in transformer oil recirculation pumps, by identifying repetition rate of detected events, amplitude, and location of those events. This information, along with a vibration spectrum, provides the necessary information to determine pump condition. When useing this technology in the analysis of noise levels on transformer walls, noise that is continuous and periodic is indicative of normal operation. Random, non-periodic activity is not normal and is caused by charges building between two points and then discharging. Degradation of insulation and generation of combustible gases are direct results of this activity. The approximate location of the source can be identified using this diagnostic technique.

Event Detection(Special Test)

Events(PD activity) in some cases, can only be detected using the A.E. as an on-line detection technique. On-line means, monitoring for non periodic bursts of energy exceeding preset thresholds. This technique is used when gasses are building up in the oil, and the partial discharge activity is occurring during off hours.

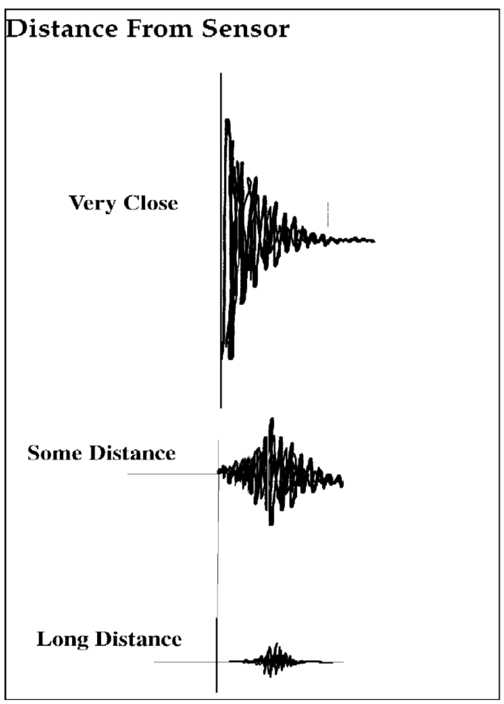


Figure 2-5
Source Locating Technique

Oil Analysis

Identification of Incipient Faults

Gases generated are a function of the material involved (oil and/or insulation) and the type, source and severity of the problem. Much research has been dedicated to analyzing the relationship between the combustible gas formation and transformer failures. A high degree of success has been achieved in determining a link between the ratios of common fault gas concentration, specific fault types, the evolution of individual fault gases and the nature and severity of the transformer fault. The detection of certain gases generated in a oil-filled transformer in service is frequently the first available indication of a malfunction that may eventually lead to failure if not corrected. Arcing, low-energy sparking, severe overloading, pump motor failure, and overheating the insulation system are some of the possible mechanisms. These conditions occurring singly, or as several simultaneous events, can result in decomposition of the insulating materials and the formation of various combustible and non-combustible gases. Normal operation will also result in the formation of some gases. In fact, it is possible for some transformers to operate throughout their useful life with substantial quantities of combustible gases present. Operating a transformer with large quantities of combustible gas present is not a normal occurrence but it does happen, usually after some degree of investigation and an evaluation of the possible risk.

Primary Causes of Combustible Gas Generation

The two principal causes of gas formation within an operating transformer are thermal and electrical disturbances. Conductor losses due to loading produce gases from thermal decomposition of the associated oil and solid insulation. Gases are also produced from the decomposition of oil and insulation exposed to arc temperatures. Four causes of gas buildup in power transformers are listed below;

Partial discharge (Ultrasonic noise)

Electrical stressing resulting in flash over which first occurs during high voltage over sharp edges of current carrying conductors.

Sparking

Single short electrical discharge lasting a microsecond or less.

Hot spots

Localized overheating.

Arcing

Prolonged electrical discharge.

Faults and their Key Gases

Fault: Overheating of conductor/oil Cellulose breakdown.
Key gas: CO, CO_2

Fault: Overheating oil.
Key Gas: C_2H_4
mild—CH_4, C_2H_6
moderate—CH_4, H_2, C_2H_2
severe—H_2, C_2H_2

Fault: Partial discharge.
Key gas: H_2
low energy—CH_4, H_2
high energy—H_2

Fault: Arcing

Key gas: H_2, CH_4, C_2H_2

Key: H_2 = Hydrogen
CO = Carbon Monoxide
CO_2 = Carbon Dioxide
$C2H_2$ = Acetylene
CH_4 = Methane
C2H = Ethane
$C2H_4$ = Ethylene

Establishing Baseline Data

Establishing a reference point for gas concentration in new or repaired transformers and following this with a routine monitoring program is a key element in the application of this guide. Generally, daily or weekly sampling is recommended after start-up.

Routine sampling intervals may vary depending on application and individual system requirements. For example, some utilities sample generator step-up transformers four to six times a year, units rated over 138 kV twice a year, and some 765 kv units are sampled monthly.

Complimentary Technology

Infrared Thermography, Ultrasonic Noise Analysis, and Vibration Analysis.

Furan Analysis

Transformer life is shortened when increased loading or other factors cause temperatures to rise. Because cellulose insulation is thermodynamically unstable, the rate of breakdown approximately doubles with each 10C rise of temperature above rating. Previously, the only way to evaluate the cellulose was to obtain a test piece from the transformer.

This practice was not practical, due to the fact that the transformer had to be taken out of service and entry made to the main tank. Usually the sample is taken from the top of the windings, and might not be representative of the overall condition. This may damage the insulation system causing more problems than before. An alternative to that procedure is evaluating the oil for the compounds resulting from cellulose decomposition (furan derivatives). Although the overall test results are effected by degassing & oil filtration maintenance, if periodic data is obtained it can be used to estimate remaining life.

Portable Instruments.

The Hydran 103B is self-contained and responds to hydrogen and carbon monoxide. Relative sensitivity to H_2 @ 100% and to CO @ 15%. It uses a gas permeable membrane coupled to a combustible gas detector.

Fixed Instruments.

The Hydran 201R sensor is mounted on the upper fill valve or a flow loop and uses a gas permeable membrane coupled to a combustible gas detector. The 201R is sensitive to H_2 @ 100%, CO @ 15%, C_2H_2 @ 8% and C_2H_4 @ 1%.

Dissolved Gas Laboratory Analysis

When a more accurate determination of the total amount of combustible gases or a quantitative determination of the individual components is desired, a laboratory analytical method using a gas chromatograph or mass spectrometer may be used.

Oil Quality Tests

Oil quality testing includes:

- Dielectric Strength
- Power Factor
- Acidity Neutralization Number
- Interfacial Tension (IFT)
- Color
- Moisture

Applications

Load Tap Changer, Circuit Breakers and Oil Filled Equipment

The idea that analysis of the hydrocarbon based gases in Load Tap Changers (LTC's) might tell something about their condition has been proven. Previous to this time only the step count and time elapsed method was used to determine when maintenance should be performed.

Only if an LTC was know to be a bad actor or the load was excessively high was maintenance performed before its scheduled service date.

It was previously believed that the use of Dissolved Gas Analysis (DGA) to determine the condition of an LTC was futile because of the large amounts of hydrocarbon gas produced during stepping. It was apparent that the use of either acetylene or hydrogen quantity as a determinant would be on no value in predicting LTC condition. It was recognized that all the combustible hydrocarbon-based gases except acetylene and hydrogen would be present, but in small quantities if there was no heating, within the tap changer compartment.

One area of concern were tap changers that had been repaired previous to using current PdM techniques, but had not had the oil degassed or changed. In these cases, tests were taken at known intervals and comparisons of gas levels made in order to establish usable baselines. Increases in gas indicate a new or continuing problem, whereas steady levels indicate a dormant or non existing problem.

Methane, Ethane and Ethylene are the key gases to use as the baseline to monitor because of the temperatures at which they are produced. Each of the gases are produced at temperatures as low as 150 degrees C but major formations of each gas do not occur until the oil is above its boiling point of approximately 300 degrees C. Methane, Ethane, and Ethylene are produced at temperatures in the ranges of 300, 500, and 700 degrees C respectively.

Although mineral oil has high solubility of hydrocarbon gases, it is recognized that diffusion is very slow and dependent on gas type and oil temperature. Gases tend to stay dissolved and must be purged after maintenance is done to create a new baseline to work from. It was also determined that the type of breather drastically affected the amount of gas maintained in solution. Closed breathing systems contain over 1000 times the levels of a free breather; a desiccant breather in the order of 10 to 50 times the level of a free breather.

Sound Level

Collecting accurate sound level data around transformers has proven to be difficult because of dividing walls, pumps, fans, motors and tap changers, etc. In lieu of the inaccuracy, documenting overall dB levels taken in exactly the same location around a transformer have been valuable in simply indicating the need to further investigate, with other diagnostic tools, what is now different near the transformer. Because the sound levels meters respond to frequencies between 120-1000 Hz very well, major increases in sounds (heard by everyday inspectors) can be documented and then investigated by the survey team.

Applications

Transformers, Pumps, Load Tap Changers

Data Acquisition and Locations

Overall dB levels are obtained in the "c" weighted mode, at the center of each side of equipment, six feet back from the closest part.

Octave Band Analysis Vs Overall Levels

Octave analysis is used to document the exact frequency contributing to a high level. This technique is used during factory acceptance testing and can be used in the field after installation, to baseline and document "as left" condition. Overall levels are easier to obtain, and when documented as part of a program, provide early warning of changing conditions.

Infrared Thermography

Thermography is a valuable tool for the SPDM program, since over 60% of the anomalies reported are found with the IR camera; however, some problems that can eventually lead to catastrophic loss can be easily overlooked. Examples of these are: performing surveys without knowledge of equipment loading; not surveying the control cabinets; and, ignoring low level increases on the shell of a tap changer or generator isophase bus. The ability to measure the temperature of an object without making direct contact with that object is ideal for the substation thermographer. Thermal imaging reveals heating patterns on electrical equipment that allows the thermographer to analyze various conditions. Knowing what temperatures (signatures) are expected and comparing this information with data obtained using other technologies such as: oil analysis, ultrasonic noise analysis/partial discharge detection, and present equipment loading, contributes significantly to a reasonable equipment condition decision making process.

Applications

Transformers, Transformer Cooling Systems, Load Tap Changers, Pumps, Motors, Circuit Breakers, Lightning Arresters, Current Transformers, Potential Transformers, Control Cabinet Components, Connections and Wiring, High Voltage Connections, Batteries and Chargers, Grounding Systems, etc.

Complimentary Technology

Ultrasonic Noise Analysis, Dissolved Gas Analysis, Vibration Analysis

Severity Criteria

A severity criteria has been developed using the knowledge and experience of the thermographic community and project experience. The severity criteria is included in the sample report included in Appendix B.

Line of Sight

The term ‘line of sight’ refers to an electrical connection that you can see, not covered by tape or inside an enclosure. The severity criteria was developed using line of sight electrical connections as the standard. This type of electrical problem is the most common and easiest to determine the cause and severity

Oil Filled Equipment and Enclosed Switchgear

The severity criteria for oil filled equipment and enclosed switchgear is determined by thermographer experience and knowledge of the equipment being surveyed. Assessing this type of equipment is most challenging. Proper training and a full understanding of substation components is necessary to effectively perform IRT in high voltage substations.

Equipment Condition

Thermographers that don't have extensive substation knowledge need additional training or guidance. A paper has been included to aid with the identification and expected thermal signatures of most substation components. See Appendix D.

Learnings from Technology Applications

General

Visual Inspections

- During this project 17% of anomalies were detected through visual inspection. A leading condition of concern was low or pegged low oil levels on current transformers, potential transformer and circuit breaker bushings.

Operational Tests

- 6% of anomalies were detected by performing operational checks. Examples include: inoperable load tap changers, cooling systems tripping on thermal overload, pumps pumping well below rated flow and fans running in reverse.

Equipment Specific

Transformers

- In order to properly trend condition and source locate anomalies ultrasonically an established baseline of data is required. Once a baseline is established the technology has been a reliable trending and locating tool.

- When acetylene gas was found in transformers, there was no clear consensus or direction on how to proceed with resolving the situation. This indicated an opportunity for development of a technique to source locate that incorporates ultrasonic/partial discharge technology.

- There were no procedures or guidelines existing for performing multi-technology, comprehensive condition assessments on energized transformers. Procedures for this type of assessment are common in power plant organizations but were absent in the Power Delivery area.

Control Cabinets

- Transformer control cabinets were found to be in poor condition—infestation with animal nests, dirt and grease, alarms jumpered out for extended periods as well as finding transformer pump & fan controls left in the manual mode—raising questions regarding the risks of static electrification. There were a high number of findings reported in this area during surveys.

- Thermography was typically not utilized by utilities for surveying control cabinets. A significant number of control cabinet thermography findings occurred during the surveys.

Oil Sampling

- A problem with dissimilar metals (galvanized fittings) and contamination of oil samples from the sample port area was identified. The contamination caused erroneously high readings of hydrogen in samples.

- Improving oil sampling techniques has potential for saving significant amounts of maintenance dollars. Dirt, moisture and galvanic contamination of samples has caused unnecessary maintenance to be performed.

Transformer Cooling Systems

- Thermography, ultrasonic/sonic listening and vibration monitoring of pumps, air flow direction and oil flow volume measurements were effective in detecting degraded or inoperable cooling systems. Typical findings showed pumps to have low output and/or fans to be inoperable.

- Pumps and fans needed to be switched on and operated for thirty minutes prior to performing thermography surveys. This allows equipment and control cabinet connections to warm-up prior to the survey and it performs a functional test of the circuits to assure that equipment does not trip off on thermal overload.

Load Tap Changers

- In order to properly assess the health of a LTC it is necessary to perform a functional check by running the LTC through taps while listening for unusual sounds via ultrasonics.

- Although typically not utilized in the industry, periodic oil sampling of LTC compartments is an effective diagnostic and trending tool.

- The use of on-line oil filtering systems for selected equipment can substantially reduce maintenance requirements.

Batteries

Symptoms of deteriorating conditions on batteries were often overlooked. A comprehensive inspection of battery condition developed. The inspection includes: checking electrolyte levels, charging circuit, observing for acid spills, lead peroxide and copper sulfate deposits as well as inspection for sulfation, discoloration, flaking and growth of plates. Additionally, when accepting delivery of new cells, posts should be checked for leakage.

Circuit Breakers

- Oil levels and leaks were often overlooked on phase tanks and bushings. On reason for this was because of their high elevation in the yard. Without optical aids such as binoculars it is very difficult and in some circumstances impossible to detect leaks and determine oil levels.

- Thermography allows the opportunity to check oil levels and compare temperature in phase tanks for oil insulated equipment and to check heaters in control cabinets and high pressure gas reservoirs.

- Ultrasonics is effective in locating pressure leaks.

Current, Potential Transformers and Bushings

- Heating can be detected by using thermography to do comparisons with like units.

- Airborne ultrasonics can be utilized to detect loose connections and arcing conditions.

- Oil levels and leaks were often overlooked.

3

RESULTS

Cost Benefit/Justification

The cost of any PDM program will depend on the size of the utility and how management chooses to approach implementation. Because utilities already utilize most of the core condition monitoring equipment (thermography, visual inspection, oil analysis, etc.) to troubleshoot equipment problems, existing equipment is utilized and augmented with training on new equipment and technologies.

The SPDM project resulted in a documented gross benefit of $15.7M with an approximate net savings of over $12.5 M. Cost benefits were calculated for 1417 of 1817 anomalies detected during the program. When including the remaining 400 anomalies benefits calculated using default values for savings (See Appendix D), the estimated gross benefit is approximately $18.1 million.

Participant Company Results

Ten utilities participated in (77) week long surveys performed through 10/1/98 by the M & D Center team with utility support. The surveys resulted in 1817 reported anomalies. Participant Company Results Table 2-1 shows the technology used, number of anomalies found and percent of overall benefit derived by all utilities in the project.

Table 3-1
Technologies/Benefits (All Utilities)

Technology	Anomalies	% of Total	Avoided Cost	%Benefit
Thermography	1194	65	10,566,127	67
Visual/Ops.	416	23	3,026,377	19
Oil	69	4	914,049	6
UT Noise	105	6	1,044,071	7
Vibration	35	2	147,240	1
Total	**1817**	**100**	***15,697,864**	**100**

***400 Anomalies benefits not included.**

An important point needs to be made about the preceding table. At first glance one might consider buying a Thermography camera and only using that diagnostic tool and DGA analysis, along with an enhanced inspection effort, to evaluate their substations/switchyards. That would be a mistake for several reasons, one is that heat is a final failure mode of oil filled equipment and on some equipment, especially transformers, internal heat generated by some anomalies could never be detected on the external surface. Fortunately, a small percentage of equipment has internal problems such as; arcing, corona, looseness of core/windings, etc., and therefore the % benefit derived from monitoring to detect these problems will be misleading.

The following table (3-2) indicates where the anomalies reported, using the survey inspection guidelines established during this project, were found.

Table 3-2
Anomalies reported by equipment type.

Transformers 864			**Disconnects 597**	
Load Tap Changers	150		Hot Connections	554
Control Cabinet	131		Misc.	43
Fans	124		Circuit Breakers 198	
Bushings	104		Hot Connections	100
Oil Pumps	50		Bushings Low Oil	50
Radiators	32		Breaker Low Oil	20
Misc.	273		Misc.	28
Other substation equipment				
PT,s; CT,s; Batteries; Etc.	158			

Of the anomalies reported in the tables above; 547 of the 1817 reported would not have been found without opening control cabinets and operating equipment as prescribed in SPDM survey guidelines and procedures. Also, 617 of the total were found using technologies and techniques other than infrared. Ultimately, the real value of this project is not the large numbers of problems found, but the development of the process that allows for only equipment in trouble to be identified and worked on. The following case studies illustrate the value of monitoring condition survey techniques:

Case Studies

Case Study One (avoided cost $199,575)

Following a transformer failure, a spare transformer was installed while repairs were being performed on the failed unit. While operating under full load, the spare unit exhibited abnormally high vibration and sound levels, and the presence of combustible gases in the oil. By monitoring the transformer weekly, it was possible to determine a safe operating condition for the transformer, relative to load. The conclusion reached using these survey results, was that the unit could operate safely at half load. Weekly surveys continued for one year, until repairs were completed on the original unit and the change-out was completed.

Case Study Two (avoided cost $54,800)

A transformer survey was requested due to an increase in combustible gas-in-oil concentration. This condition indicated arcing/sparking in the oil. Discharges were detected with the ultrasonic fault detector. Source location was accomplished on the energized transformer prior to the internal inspection. An acoustic event counter was installed in the location of the greatest activity. Monitoring continued until the unit could be removed from service. An internal inspection revealed that the fault was located in the exact spot indicated by the fault detector. Repairs were completed on a damaged connection, and the unit was returned to service. No further abnormal activity was detected.

Case Study Three (avoided cost $332,300)

A thermography survey detected a 450C temperature rise on a high voltage bushing of a GSU transformer. This condition went undetected by the station. The transformer was removed from service and the damaged bushing was replaced.

Case Study Four (avoided cost $1,200,000)

A thermography survey of a main generator excitation transformer detected an abnormally cool radiator. The bottom radiator valve indicated that it was in the 'open' position, but it was actually closed. The transformer was severely overheating and destined for failure. A broken valve stem was found and the valve was replaced. The plant thermography program was designed to only recognize hot spots and only on the primary high voltage connections. The substation thermographer was surveying the switchyard and by chance happened to look in the direction of the excitation transformer. As a result, the problem was instantly recognized and reported.

Case Study Five (avoided cost $5,200)

Unexplained high concentrations of hydrogen gas was being detected in several transformers. Extensive maintenance was performed over several years to determine the cause, costing the utility over $100,000. The use of portable oil sampling equipment, allowed the test results to be analyzed at a frequent rate (10 minutes), however, inconsistent results were obtained from samples taken just minutes apart. A closer look at the sampling line on these transformers revealed the presence of galvanized fittings. It was then realized that the hydrogen was being generated in the sampling line, not the transformer.. Galvanized fittings in the oil sampling line of a transformer can generate hydrogen gas and subsequently cause misleading results from a dissolved gas analysis. The galvanized fittings were replaced and the oil sample results returned to normal.

Case Study Six (avoided cost $225,200)

A thermography survey detected a 7C temperature rise on a main generator oil circuit breaker. One tank was warmer than the other two. The thermographer from the plant passed over this anomaly for two reasons. First, the plant has a 10°C limit on taking action; and secondly, and more importantly reason is, the thermographer was an I&C technician, who was following the guidelines for reporting thermal anomalies in the plant. He didn't understand the operation of the switchyard equipment. The substation thermographer did a survey the next day, and he rated the problem as 'critical'. The scheduling for these jobs was done from two different offices, the overlap in equipment surveyed was by chance. The unit was removed from service and an inspection revealed severe burning and misalignment of the main contacts. Any temperature rise above ambient on an OCB must be investigated.

Case Study Seven (The avoidable cost was $350,000)

A routine operator's survey detected an abnormal temperature rise on the load tap changer compartment of a transformer; However the operator's warning was ignored. The tap changer burned 'open', causing the series winding in the main tank to overload and partially melt. The transformer was removed from service and scheduled for a rewind.

Cost Avoidance Calculations

Management support is critical to the success of a program. In order to gain and continue this support, program costs and savings should be documented. Each utility in the SPDM project agreed to calculate cost benefits as described in this section, although the overall value of participating in this project can be presented other ways. For example, the load tap changer condition determination techniques, that allow deferral or elimination of preventive maintenance (developed primarily at South Carolina Electric and Gas), can be used by other participating utilities and could be used to justify their overall SPDM project benefit.

Cost Benefit Calculation Method

The avoided cost savings earned by preventing equipment failure can cover a wide range of value, from damage to one particular component to a catastrophic failure of a large transformer and surrounding equipment. By following the guidelines developed as part of this project for cost benefit determination, the benefits of detecting a failure mechanism at work on a system or component before the actual failure, are quantified in terms of probable dollars saved. In order to do this, the costs of eliminating the failure mechanism in a timely fashion are compared to the likely costs incurred if the failure mechanism was not corrected, and the component or system failed. See Appendix B for an example.

The approach used in the analysis is to consider three possible failure scenarios:

Worst Case	A catastrophic failure requiring replacement or a complete rebuild of the equipment. Also taking into account damage to surrounding equipment, environmental *damage* and clean up, engineering replacement of equipment, costs associated with emergency services, etc.
Possible Case	A moderate failure requiring replacement parts and labor.
Probable Case	A loss of performance or minor failure requiring replacement parts and labor.

Step 1—Estimate the percentage likelihood out of 100% of each of the three scenarios occurring; with the sum of the three percentages equal to 100%.

Step 2—Multiply the projected cost of each of the three scenarios by its estimated percent likelihood; the sum of these three products is the *weighted estimated savings*.

Although the calculations are straightforward, the effective use of the guidelines can be a challenge and are often subject to opinion and experience. Your historical knowledge can be of substantial value in determining the criticality of the component or system to the operation of the facility in order to project the benefits and the extent of each of the failure scenarios. In preparing cost estimates, remember to include man-hours, transportation of parts and equipment, cost of replacement parts and equipment and damage to adjacent equipment. Avoided maintenance may also be included. Appendix D contains default benefit values for common anomalies found during the project, these values are conservative and provide good starting point dollar values. As the program matures and becomes more effective, the savings and benefits directly attributable to averting failure will diminish and the benefits derived from better understanding of equipment condition will increase. The knowledge of equipment will enable deferring or eliminating selected time-based maintenance tasks and optimizing schedules such that maintenance/overhauls occur when required.

4

PROGRAM MANAGEMENT

Prior to beginning or expanding a SPDM program, take stock of where you are. A properly executed predictive maintenance process is not just the practice of using diagnostics to detect equipment faults or degredation. The program should be a direct extension of means to meet goals set forth by management—reducing costs and improving performance through:

- prioritizing and redirecting resources to equipment in need.
- reducing the scope and corresponding costs of preventive and corrective maintenance tasks.
- reducing the amount and/or frequency of corrective and preventive maintenance tasks.
- extending equipment life.
- increasing availability and performance of equipment.

Experience showed that it can take several years to establish a robust SPDM process. Program development and implementation requires an investment in new test equipment, personnel training, as changes to roles, goals and responsibilities of individuals and organizations, new lines of communication, development of procedures and support changes to the cultural values of the organization.

Experience with initiating SPDM programs led to the development of a six (6) step process to follow when preparing to initiate a new program or enhance a existing program:

1. Consider why you want to implement or enhance a SPDM program. Determine exactly how SPDM will support achievement of financial, safety, reliability, regulatory or other goals.

2. Establish the program formally. Place an individual or entity in charge and develop specific goals for the SPDM programmer in the areas of organizational readiness, identification of components and application of technologies.

3. Formulate a detailed Action Plan with task lists and a schedule for completion.

4. Execute the plan by procuring equipment, educating personnel in roles and responsibilities and technology applications.

5. Create measures and means to track and evaluate program effectiveness.

6. Automate the process.

Assessment Process

Experience with implementing the SPDM process showed that many organizations used existing technology effectively and were lacking in the areas of program coordination. Alternately, some had programs well coordinated and lacked the effective use of technologies. As the TC progressed, a listing of assessment areas were developed from “best practice” observations. From this, a SPDM organizational assessment process was developed and an assessment was performed with one utility. The assessment looked at topical “best practice” areas and at the same time took a “systems” view of the organization—looking at how technologies, people and processes were integrated and optimized to achieve the goals of the program. Topical areas included:

- Identification of condition information sources
- Data Collection, analysis and integration methods
- Information dissemination and communication
- Decision ownership
- Programmatic coordination, guidelines and descriptions
- Prioritization schemes
- Work process analysis/work flow diagrams
- PM Task auditing methods
- Program performance metrics
- Training and qualification plans
- Return on Investment (ROI) methods and calculations
- Program automation tools

- Illustration of program goals
- Identified roles & responsibilities
- Planning & scheduling processes
- Technology application descriptions

The assessment identified strengths and weaknesses of the program and detailed an action plan for improving the program. Figure 4-1 depicts a graphic representation of assessment results.

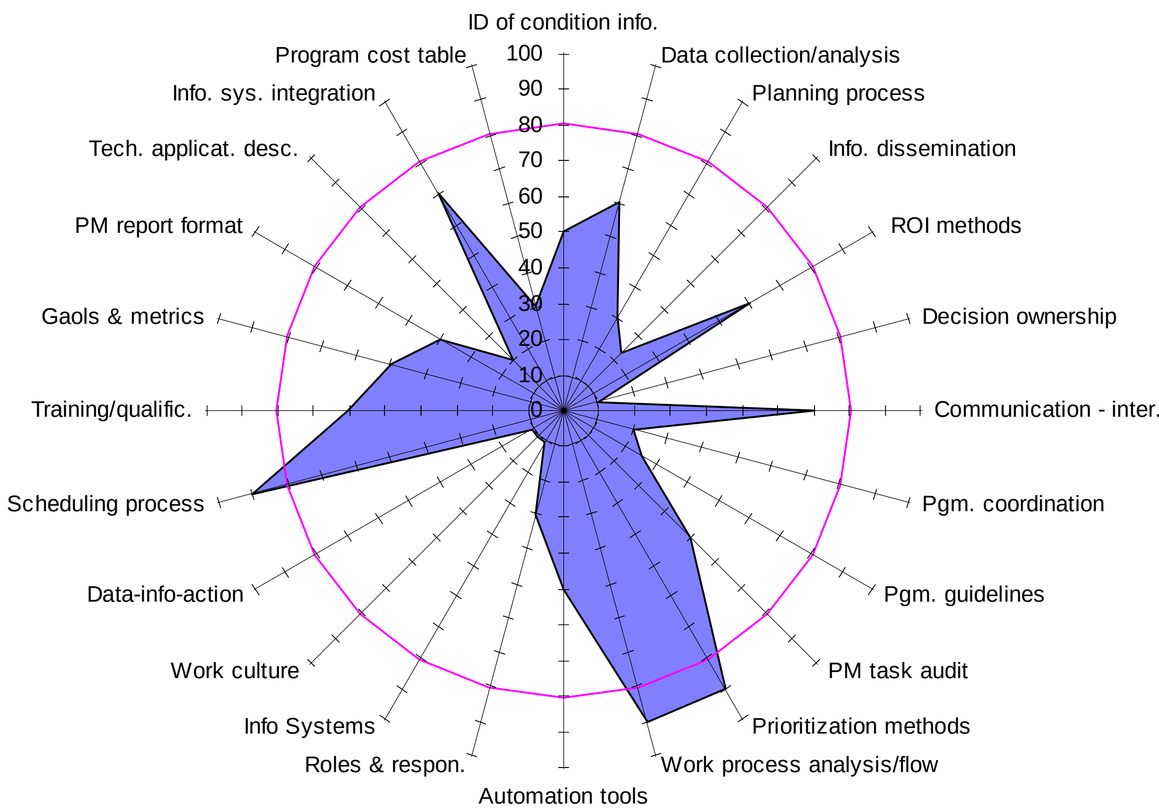


Figure 4-1
Graphic Representation of Program Assessment Results

Automation and Software

Implementing SPDM has several challenges that have to do with managing large amounts of data and the possibility of using information technology to automate data collection as well as turn raw data into easily accessible information. During the SPDM pilot process field crews collected large amounts of data. Baseline condition data was recorded on paper and data on anomalies or findings were complied into reports and distributed to various personnel responsible for deciding on follow-up action. Condition or operational data from other existing sources—oil analysis databases, operations logs, maintenance work order histories and others were utilized for assessing condition of equipment and analyzing proposed changes to preventive and predictive maintenance program routines. Implementing a SPDM program can create substantial amounts of new paperwork and time consuming work activities dealing with additional data and decisions. Opportunities for automating certain portions of the process, such as field data collection, reporting of anomalies and performing operations & maintenance decision analysis are evident. In addition, there is the opportunity to automate all aspects of the SPDM process with integrated software.

Collection of substation survey equipment condition data

During the SPDM project technicians recorded data on equipment condition on paper forms (Attachment B provides samples). Several utilities (unrelated to the SPDM project) have pilot projects in-progress to automate power plant and substation operator rounds by utilizing hand held electronic devices capable of downloading data. This technology can be adapted for use with the substation survey process.

Managing action on equipment anomalies

The SPDM project also commissioned work with participant utility South Carolina Electric and Gas to develop software for handling anomalies. This program was designed from commonly available off-the-shelf software and provides the ability to record all pertinent information on the anomalies, track completion of work and produce a wide variety of reports.

Integrated solution

The SPDM project also commissioned work on integrated software to tie together the SPDM process. The Maintenance Management Workstation (MMW) was designed to give users quick access to all data from substation condition surveys, on-line and periodic diagnostic monitoring systems and other critical information sources. MMW gives users access to multiple databases to view and trend all data related to specific equipment. The software is currently in the pilot implementation stages.

Training Management

The training performed to support the SPDM program was performed in two ways: classroom and hands-on during actual substation surveys. Three important aspects of the training were developed; programmatic, technical and analytical.

Programmatic

Outlines the functions, responsibilities and duties of all personnel involved in the SPDM. Communication is a major factor in achieving success, workers are receptive to new ideas, such as extended time frames on PM's and participating in failure analysis when they are fully aware and involved in the process. Our experience has been, that the more involved the survey team is in the SPDM program, the more supportive and enthusiastic the engineering support group will be.

Technical

Technical training is required in two areas, theoretical and practical. Theoretical is needed in order for personnel to become and remain proficient as survey technicians. Practical training is performed to demonstrate the proper use of diagnostic equipment, procedures and guidelines.

Analytical

Personnel performing surveys not only need to know the technology capabilities and limitations, they should have extensive knowledge of proper equipment operating modes and the specific equipment failure modes. For examples, see Appendix C—IR Component Identification.

In order to adequately train personnel, utility survey team personnel were judged to be qualified to perform surveys unsupervised after fulfilling the requirements in Table 4-1.

Table 4-1
Qualifications Matrix

Technology	Training	Field Experience	Fully Qualified
Visual	OJT	Three supervised substation visits	Substation Group Sign-Off
Infrared Thermography	Classroom Level I	N/A	N/A
Infrared Thermography	Classroom Substation Component ID	5 Substations with SPDM Group	Substation Group Sign-Off
Infrared Thermography	Classroom Level II	5 Substations with SPDM Group	Substation Group Sign-Off
Ultrasonic Analysis	Classroom and OJT	5 Transformers, 5 LTCs	Substation Group Sign-Off
Vibration Analysis	Classroom and OJT	5 Transformers, 5 LTCs	Substation Group Sign-Off
Sound Analysis	Classroom and OJT	5 Transformers, 5 LTCs	Substation Group Sign-Off
Oil Analysis	Classroom and OJT	5 Transformers, 5 LTCs	Substation Group Sign-Off
Cost Analysis	Classroom and OJT	Complete 5 avoided cost studies	Substation Group Sign-Off
Data Base Management	Classroom and OJT	Set-up, Drawings, Data Entry	10 transformers entered into database
Program Administration	Classroom and OJT	Obtain Resources and Support	Communicate occurrences and program success to upper management.

5

REFERENCES

1. Predictive Maintenance Applied to Generator Step-up Transformers, Giesecke, Jon L., paper given at EPRI Fossil Plant Maintenance Conference, Baltimore, MD. July 1996.

2. Determining on-line LTC Condition, Spencer, George M., paper given at EPRI LTC Conference, Tampa, FL. December 1996.

A

PROCEDURES

Procedure For Vibration Testing Of Transformers

1.0 *PURPOSE*:

1.1 To provide instruction for an effective method of collecting and evaluating vibration data on transformers and transformer cooling pumps.

2.0 *SCOPE*:

2.1 To provide the technical guidance and detailed steps required to ensure proper and meaningful vibration testing of transformers and transformer cooling pumps.

3.0 *RESPONSIBILITIES*:

3.1 Individuals performing examinations to this procedure shall successfully complete a formal training program in the fundamentals of vibration testing and receive sufficient training with field equipment to insure accurate data collection.

4.0 *REFERENCES*:

4.1 Manufacturers equipment manual for Data Collector/Analyzer.

5.0 *DEFINITIONS*:

CCW: Counter Clockwise

6.0 *PREREQUISITES*:

6.1 Portable Data Collector/Analyzer with sensor.

6.2 Document all operating conditions and load information available relating to equipment being surveyed on the Transformer Examination Data Sheet (exhibit 11.1).

7.0 *INSTRUCTION*:

7.1 For transformer shell, identify each side of the transformer. For this procedure the high voltage side of the transformer shall be identified as the high side or side one. The remaining sides shall be identified numerically (2, 3, and 4) CCW. (The numerical value of the low voltage side of the transformer may be referred to as the low side.) All data will be collected working CCW (left to right).

7.1.1 For the transformer cooling pumps, identify each pump by a number starting on the high side counting CCW around the transformer.

7.2 Program the data collector/analyzer equipment settings as follows for transformer shell examination:

1000 HZ Maximum Frequency

Acc to Vel

7200 RPM

.5 in/sec Full Scale

for transformer cooling pump examination:

400 HZ Maximum Frequency

Acc to Vel

7200 RPM

.5 in/sec Full Scale

7.2.1 Additional MENU Settings may be programmed according to manufacturers instructions at the discretion of the operator.

7.3.1 For transformer shell examination, mount the sensor in the corner of the transformer wall, five feet up from the bottom and approximately one foot in from the end , and collect vibration data.

7.3.2 For transformer cooling pump examination, mount the sensor on the impelor section of the pump to obtain three readings, one a vertical reading, one horizontal reading and one axial reading and collect vibration data.

7.4 Repeat steps 7.2 through 7.3.2 to collect data on each corner of the transformer for a total of eight individual readings. and three on every pump. Vibration readings may be taken at additional locations if determined necessary by the operator.

8.0 *ACCEPTANCE STANDARDS*:

Severity Criteria (attachment 10.1)

9.0 DOCUMENTATION:

9.1 All operating conditions, load information, data locations and overall vibration results shall be recorded on the Transformer Data Sheet (exhibit 11.1).

9.2 If the results indicate any condition described in the Severity Criteria (attachment 10.1), these results shall be documented on the Occurrence Report Form (exhibit 11.2) and forwarded to the responsible department for appropriate action.

10.0 ATTACHMENTS:

10.1 Severity Criteria

11.0 *EXHIBITS*:

11.1 Transformer Data Sheet

11.2 Occurrence Report

Procedure for Sound Level Testing of Transformers

1.0 *PURPOSE*

1.1 To provide instruction for an effective method of collecting and evaluating sound level data on transformers.

2.0 *SCOPE*:

2.1 To provide the technical guidance and detailed steps required to ensure proper and meaningful sound level testing of transformers.

3.0 RESPONSIBILITIES:

3.1 Individuals performing examinations to this procedure should receive formal training in the fundamentals of sound measurement and receive sufficient training with field equipment to ensure accurate data collection.

4.0 REFERENCES:

4.1 Manufacturers equipment manual for sound level equipment

4.2 ASNI/IEEE Standard, Section 13, Audible Sound Tests

5.0 DEFINITIONS:

5.1 Weighting Network: an electronic circuit with a sensitivity that varies with frequency and stimulates an equal loudness contour.

5.2 Linear Network: an electronic circuit that enables the signal to pass through unmodified.

6.0 *PREREQUISITES*:

6.1 A field portable sound level meter.

6.2 Document all operating conditions and load information available relating to equipment being surveyed on the Transformer Data Sheet (exhibit 11.1).

7.0 INSTRUCTION:

7.1 Perform a calibration check according to manufactures instructions before testing begins.

7.2 Set the weighting network switch to Linear.

7.3 Set meter switch to desired position. (Due to fluctuating levels usually present, the slow position is recommended, subject to operator desecration.)

7.4 Position sound level meter approximately 5' above ground level in the center of the transformer wall and approximately 6' back from the transformer (including pumps, radiators, etc.).

7.5 Attach windscreen to microphone and adjust the range sensitivity to obtain a positive reading.

7.6 Mount meter in position on a tripod or hold meter at arms length to prevent operator interference.

7.7 Document results on the Transformer Data Sheet.

7.8 Perform step 7.4 through 7.7 for each side of the transformer.

7.9 Repeat field calibration at completion of data collection.

8.0 *ACCEPTANCE* STANDARDS:

See attachment 10.1, Severity Criteria

9.0 DOCUMENTATION:

9.1 All operating conditions, load information and results shall be recorded on the Transformer Data Sheet (exhibit 11.1).

9.2 If results indicate any condition described in the Severity Criteria (attachment 10.1) these results shall be documented on the Occurrence Report Form (exhibit 11.2) and forwarded to the responsible department for appropriate action.

10.0 ATTACHMENTS:

10.1 Severity Criteria

11.0 EXHIBITS:

11.1 Transformer data sheet

11.2 Occurrence Report

Procedure for Partial Discharge Detection/Ultrasonic Noise Analysis in Transformers

1.0 PURPOSE:

1.1 To provide instruction for an effective method of detecting partial discharge/corona activity in transformers.

2.0 *SCOPE*:

2.1 To provide the technical guidance and detailed steps required to ensure a proper and meaningful technique for the detection of partial discharge, corona, arcing and sparking in transformers using ultrasonic noise analysis.

3.0 *RESPONSIBILITIES*:

3.1 Individuals performing examinations to this procedure should have sufficient knowledge of equipment operation and response values before collecting data.

4.0 *REFERENCES*:

4.1 Manufacturers equipment manual for Sonic/Ultrasonic Fault Detector.

5.0 *DEFINITIONS*:

5.1 Partial Discharge: An electrical discharge that partially bridges the insulation between conductors.

5.2 Corona: Electrical stressing resulting in ionization

5.3 DGA: Dissolved gas analysis

5.4 TDC: Top Dead Center

5.5 CCW: Counter Clockwise

5.6 Sonic: the frequency within the audible range of the human ear; a range of 20 Hertz to 20000 Hertz

5.7 Ultrasonic: the frequency range greater than the highest audible frequency generally regarded as being higher than 20,000 Hertz to approximately 1000 Megahertz.

5.8 Couplant: a substance used between the face of the transducer and test surface to permit or improve transmission of ultrasonic energy across this boundary or interface.

6.0 *PREREQUISITES*:

6.1 A field portable Sonic/Ultrasonic Fault Detector.

6.2 Document all operating conditions and load information available relating to equipment being surveyed on the Transformer Data Sheet (exhibit 11.1)

7.0 *INSTRUCTIONS*

7.1 Identify each side of the transformer. For this procedure the high voltage side of the transformer shall be identified as the high side or side one. The remaining sides shall be identified numerically (2, 3, and 4) CCW. (The numerical value of the low voltage side of the transformer may be referred to as the low side.)

7.2 Data collection will be performed with the Sonic/Ultrasonic Fault Detector at the following locations:

7.2.1 On each side of the transformer at three vertical elevations, approximately 2', 5' and 7' from the bottom of the transformer and horizontal locations, starting approximately 1' from the corner and evenly spaced between corner locations. Horizontal spacing should not exceed 6'. (data locations are subject to obstructions and size of transformer.)

7.2.2 On one or more locations on the tap changer. Operate LTC while collecting data if possible.

7.2.3 One axial reading, one vertical reading and one horizontal reading on the impeller section of each oil pump.

7.3 Data collection will be performed with the Sonic/Ultrasonic fault detector as follows:

7.3.1. Using couplant, place the transducer for the Sonic/Ultrasonic fault detector on locations described in 7.2 of this procedure for a minimum of 10 seconds each. Record data levels in both the sonic and ultrasonic mode on the transformer data sheet in the space provided for each location. Note: Headset must be worn while collecting data with the Sonic/Ultrasonic fault detector.

7.3.2 If random bursts are detected while collecting data using the headset, or if a significant increase in amplitude is detected when the results are compared to previous data, a reference must be noted on the data sheet and further investigation may be required. (refer to Severity Criteria/attachment 10.1 for further instruction)

8.0 *ACCEPTANCE STANDARDS*:

See Attachment 10.1

9.0 *DOCUMENTATION*:

9.1 All operating conditions, load information and fault detector values shall be recorded on the Transformer Data Sheet (exhibit 11.1).

9.2 If results indicate any condition described in the Severity Criteria (attachment 10.2) these results shall be documented on the Occurrence Report (exhibit 11.2) and forwarded to the responsible department for appropriate action.

10.0 *ATTACHMENTS*:

10.1 Severity Criteria

11.0 *EXHIBITS*:

11.1 Transformer Data Sheet.

11.2 Occurrence Report

Procedure for Infrared Thermography of Transformers and Substation Equipment

1.0 *PURPOSE*:

1.1 To provide instruction for an effective method of detecting abnormal equipment conditions using infrared thermography.

2.0 *SCOPE*:

2.1 To provide the technical guidance and detailed steps required to ensure a proper and meaningful thermography examination to detect thermal anomalies of transformers, circuit breakers, disconnects and other associated substation components.

3.0 *RESPONSIBILITIES*:

3.1 Individuals performing examinations to this procedure should successfully complete a formal infrared thermography training program and receive training or have the experience necessary for proper identification of substation equipment and an understanding of the normal operating conditions of substation equipment.

4.0 *REFERENCES*:

4.1 Manufacturers equipment manual for infrared equipment.

5.0 *DEFINITIONS*:

5.1 Thermography: A non-contact measurement of electromagnetic radiation emitted from a target, that is proportional to the target temperature.

5.2 Infrared (IR): Lying outside the visible spectrum at its red end; the use of thermal radiation of wavelengths longer than those of visible light.

5.3 Hot Spot: Localized area of abnormal resistance or overheating

6.0 *PREREQUISITES*:

6.1 A field portable thermal imaging radiometer (IR camera) with at least ±2°C or ±2% accuracy.

6.2 Document all operating conditions and load information available relating to the equipment being surveyed on the Transformer Data Sheet (exhibit 11.1).

7.0 *Instruction*:

7.1 Set parameters on the IR camera according to instructions in the manufactures operators manual.

7.1.1 Transformers:

7.1.1.1 Transformer Shell: Determine the normal operating temperature of the transformer shell, examine all sides of the transformer and record any temperature rise on the shell wall greater than or equal to 10°C. (Conditions may exist within the transformer that contribute to shell hot spots.)

7.1.1.2 Transformer Bushings: Determine the normal operating temperature and document any temperature rise greater than or equal to 10°C.

7.1.1.3 Tap Changer: Examine the tap changer and record the temperature differential relative to the main tank. Also record the temperature profile from top to bottom. (The tap changer should not be hotter than the main tank of the transformer and should not be more than 5°C different from top to bottom; any temperature rise may be an indication of a problem.)

7.1.1.4 Control Cabinet: Examine all connections and components within the control cabinet. (Understanding of control component functions is necessary for accurate evaluation; high temperatures on some components can be normal operating temperature, ie. cabinet heaters). Record any temperature greater than or equal to 10°C above normal.

7.1.2 Overhead Connections and other substation support equipment: Determine the normal operating temperature and document any temperature rise greater than 10°C.

7.1.3 Oil filled circuit breakers: Any temperature greater than ambient needs to be investigated. Also the temperature profile from top to bottom. should not be more than 5°C. Any temperature rise may be an indication of a problem

8.0 *Acceptance Standards*:

See attachment 10.1

9.0 *Documentation*:

9.1 All operating conditions, load information and results shall be recorded on the Transformer Data Sheet (exhibit 11.1).

9.2 If thermograms and/or photographs are required for results documentation, the Thermography Report Form (exhibit 11.3) may be used in addition to the Transformer Data Sheet to document results.

9.3 If results indicate any condition described in the Severity Criteria (attachment 10.1) these results shall be documented on the Occurrence Report Form (exhibit 11.2) and forwarded to the department responsible for appropriate action.

10.0 *Attachments*:

10.1 Severity Criteria

11.0 *Exhibits*:

11.1 Transformer Data Sheet

11.2 Occurrence Report

11.3 Occurrence Report

Procedure for Oil Sampling of Transformers for Gas in Oil Analysis

1.0 *PURPOSE*:

1.1 To provide instruction for an effective method of extracting oil samples from power transformers for Gas in Oil Analysis.

2.0 *SCOPE*:

2.1 To provide the technical guidance and detailed steps required to ensure a proper and meaningful method of extracting oil samples from power transformers for dissolved gas analysis and field diagnostics.

3.0 *RESPONSIBILITIES*:

3.1 Individuals performing examinations to this procedure should have sufficient knowledge of equipment operation before extracting samples and documenting results.

4.0 *REFERENCES*:

4.1 None.

5.0 *DEFINITIONS*:

DGA—Dissolved Gas Analysis.

6.0 *PREREQUISITES*:

6.1 Oil sampling syringe with three position stopcock.

6.2 1/8" ID clear plastic (tygon) tubing

6.3 Pipe plug with 1/8″ tube fitting or sampling valve.

6.4 Waste oil container.

6.5 Document all operating conditions and available load information relating to equipment being surveyed on the Transformer Data Sheet (exhibit 11.1).

6.6 The apparatus to be sampled must be under positive pressure.

7.0 *INSTRUCTION*:

7.1. Check that the drain valve on the transformer sampling line is fully closed. Remove the large pipe plug from the end of the sample line piping. Inspect the condition of the plug, pipe and valve for debris, rust, water, etc. Open the main valve just enough to flush the valve, pipe and thread area. Drain flush oil into waste oil container. Close the valve and wipe the threads, pipe and valve area with a clean lint free cloth, re-flush and close valve.

7.1.1 Install the pipe plug with a 1/8" tube fitting in place of the original pipe plug on sample line piping.

7.2 Use clear plastic (tygon) tubing to connect the syringe to the pipe plug fitting. New tygon tubing should be used if the oil sample is going to be used for a complete dissolved gas analysis. Any air should be expelled from the syringe. Turn the stopcock handle to permit flushing through the side port of the stopcock. (Note: The handle of the stopcock always points to the closed port, the other two ports then provide the oil flow path.)

7.3 Thoroughly flush the sample valve through the tygon and stopcock and into the waste oil container. Drain off approximately one quart of oil.

7.4 Turn the stopcock to allow oil(approx. 40 cc's) to flow into the syringe. Do not pull the syringe piston manually. This can result in bubble formation. The internal pressure in the transformer should move the piston.

7.5 Close the sampling valve. Disconnect the tygon tubing from the pipe plug fitting and hold the opened end of the tubing into waste oil container. With the syringe in the vertical position, pointing up, and the tygon tube held in the waste container, turn the stopcock handle towards the side tap of stopcock. Maintain positive pressure on the syringe piston to keep it from moving. Depress the syringe piston to eject any air bubbles and leave 30 cc's or more of oil remaining in syringe for testing. Close the stopcock to seal oil in syringe. Prevent oil sample from exposure to direct sunlight

7.6 Replace the original pipe plug. Clean up any drips or spills. Dispose of the waste oil using approved methods.

7.7 Follow instructions in the manufacturers equipment manual for the field portable test set to perform field oil analysis.

8.0 *ACCEPTANCE STANDARDS*:

See attachment 10.1

9.0 *DOCUMENTATION*:

9.1 All operating conditions, load information and results shall be recorded on the Transformer Data Sheet.

(exhibit 11.1)

9.2 If results indicate any condition described in the Severity Criteria (attachment 10.1) these results shall be documented on the Occurrence Report form (exhibit 11.2) and forwarded to the department responsible for appropriate action.

10.0 *ATTACHMENTS*:

10.1 Severity Criteria

11.0 *EXHIBITS*:

11.1 Transformer Data Sheet.

11.2 Occurrence Report

DIAGNOSTIC TECHNOLOGIES EQUIPMENT APPLICATION MATRIX

Therm-ography	Hand Held Radiometer	Dissolve Gas Analysis	Airborne Noise Analysis	Vibration	Temp	Airflow	Partial Discharge Detection	Visual	Hydran Oil Test	Ultra Sonic Flow	Oil Di-Electric Strength	Components
B	D	A	R	B	B	C	A	A	B	C	C	GENERATOR STEPUP TRANS.
B	D	A	R	B	B	C	A	A	B	C	C	TRANSMISSION TRANS.
B	D	A	R	B	B	C	A	A	B	C	C	DISTRIBUTION TRANS.
B	R	R	R	-	B	-	B	A	-	-	-	CURRENT TRANS.
B	R	R	R	-	B	-	B	A	-	-	-	POTENTIAL TRANS.
B	B	-	B	A	C	-	B	B	-	A	-	TRANS. OIL PUMPS
B	D	B	-	R	B	C	A	A	B	-	C	OIL FILLED REACTOR
B	B	-	C	B	A	-	-	A	-	-	-	TRANS. RADIATORS
A	B	A	B	B	A	-	A	C	-	-	B	TRANS. TAP CHANGER
A	D	-	-	-	-	-	-	A	-	-	-	TRANS. CONTROL CABINET
A	B	B	R	R	B	-	B	A	-	-	A	OIL CIRCUIT BREAKER
R	-	-	R	R	R	-	R	A	-	-	-	AIR MAGNETIC BREAKER
R	R	-	R	R	R	-	R	A	-	-	-	AIR BLAST CIRCUIT BREAKER
R	R	-	-	-	R	-	-	A	-	-	-	CONTROL BATTERY
A	D	-	R	-	-	-	-	A	-	-	-	PRIMARY CONNECTIONS
A	D	-	R	-	-	-	-	A	-	-	-	DISCONNECTS
R	R	-	B	-	R	-	R	A	-	-	-	ENCLOSED SWITCHGEAR
R	-	-	-	-	-	-	-	A	-	-	-	GROUND NETWORK
B	C	B	R	R	B	-	B	A	B	-	C	OIL FILLED REGULATOR
B	D	B	R	R	B	-	B	A	B	-	C	LIGHT & POWER TRANS.
A	D	-	-	-	-	-	-	A	-	-	-	D.C. CONTROL BUS
A	C	-	-	-	-	-	-	A	-	-	-	CONTROL FUSES
A	C	-	-	-	-	-	-	A	-	-	-	TERMINAL BLOCKS
B	R	-	R	-	C	-	B	A	-	-	-	ENCLOSED BUS
A	D	-	-	-	A	-	-	A	-	-	-	COMPARTMENT HEATERS
R	-	-	R	-	-	B	-	A	-	-	-	AIR FILTERS
B	R	-	R	-	-	-	R	A	-	-	-	CABLE SPLICES & TERMINATIONS
A	D	-	R	R	B	C	B	A	-	-	-	REACTORS
-	-	-	B	-	-	-	-	A	-	-	-	NITROGEN SYSTEMS
-	-	-	A	-	-	-	R	A	-	-	-	AIR SYSTEMS
A	B	-	C	A	B	-	B	A	-	-	-	MOTORS
A	-	-	C	-	R	-	B	A	-	-	-	LIGHTNING ARRESTORS
A	-	-	C	-	R	-	-	C	-	-	-	CARRIER CURRENT WAVE TRAPS
A	-	-	C	-	-	-	B	B	-	-	-	INSULATORS
B	D	-	-	-	R	-	-	A	-	-	-	BATTERIES
B	R	R	B	-	-	-	B	B	-	-	-	BUSHINGS
B	R	-	B	-	-	-	B	B	-	-	-	SF6 BREAKERS

"A", is the most effective.
"R" = Research

A B C D

B

FORMS

Guideline for Substation Data Collection

1. Notify the Load Dispatcher / Operator of your presence and purpose in the Substation.

2. Obtain load information.

3. Perform a visual inspection of the switchyard and the station battery.

   Note: Be aware of safety in the yard.

   Look at:

   Level gauges, temperature gauges, oil leaks, flow indicators on pumps, heat discoloration of equipment, cracked insulators, pealed paint, fence and building condition, battery plate condition and innercell connections. etc.

   Listen for:

   Odd noises coming from any component in the substation.

   Feel for:

   The direction of air flow and temperature of the air from radiator exhaust.

4. Fill out the information section of the transformer survey sheet. Make a drawing of the transformer and note the survey locations.

5. Perform a sonic/ultrasonic examination of transformer and tap changer. Raise or lower load tap changer one position; listen for any significant change in sound level and listen with the fault detector for any unusual arching sounds and check all load information for unusual changes.

6. Perform sound level and vibration readings on the transformer shell.

7. Perform an Infrared Inspection of the Substation. Turn on all fans and pumps 15 minutes prior to the infrared inspection. Be aware of static electrification.

   Look at:

   The transformer shell for unusual heating patterns, overhead connections and disconnects, control cabinet connections, oil temperature comparison from the gauge reading to radiator inlet, differential temperature between inlet and outlet of cooling system, differential temperature between the tap changer compartment and the main tank, pumps, motors, lightning arresters, ground straps, etc.

8. Obtain oil samples from the main tank. Perform an analysis using the Hydran 103B. Send any questionable samples to the lab for a complete DGA. Send sample for oil quality tests.

9. Obtain oil samples from the LTC contractor compartment. Send samples for a DGA and oil quality tests.

10. Perform an airborne ultrasonic inspection. Re-survey using infrared, any questionable ultrasonic findings.

11. Complete a written report of any anomaly detected.

Note: All of the above steps are required to provide sufficient information for an accurate judgment of equipment condition. This guideline has been developed to provide a systematic approach to perform a safe, comprehensive substation survey.

Avoided Cost Worksheet

Substation: YOUR SUB **Equipment:** #2 Transformer **Date:** 11/14/95

Occurrence Report # WP96-001 **Special Test #** ____

Issue: A 25 C temperature rise was detected on the load tap changer. The reference temperature is from the main tank at the LTC elevation. The Hydran reading is 14,563 ppm

Part 1. Repair / Replacement Estimate

Worst Case: Catistrophic failure of transformer

Possible: Catistrophic failure of Load Tap Changer

Probable: Heavy damage to LTC and board

Actual: Cleaned, inspected and overhauled LTC
There was heavy coaking on several of the contacts. The reversing switch contacts were replaced.

Worst Case:	**$1,200,000**	**Possible:**	**$35,000**	**Probable:**	**$12,000**
% chance	**5.00%**	**% chance**	**15.00%**	**% chance**	**80.00%**

Actual Cost of Repair:	**$4,500**

Part 2. Total Cost Benefit = Total Savings Minus Actual

Worst Case	5.00%	+	$60,000.00
Possible	15.00%	+	$5,250.00
Probable	80.00%	+	$9,600.00
Total Savings		=	$74,850.00
Actual Cost		-	$4,500.00
Cost Benefit		=	$70,350.00

Note: Cost estimates include man hours, transaction of parts and equipment, cost of replacement parts and equipment, damage to adjacent equipment. Avoided maintenance is also a cost savings to be considered.

AVOID COST DEFAULT VALUES

	Avoided Cost - Default Values					
Equipment	Component / Anomaly	Severity	Criteria	Description	GSU Factor	Default Benefit Value *
Transformer, Main Tank	Partial Discharge Detected	Serious	Any Acetylene	Confirmed by DGA	X4	$50,000
Transformer, Main Tank	Internal Vibration / Core Looseness	Intermediate	.25 / .5 ips Harmonic	Confirmed by DGA & Internal Insp.	X4	$10,000
Transformer, Main Tank	Internal Vibration / Core Looseness	Serious	.5 / 1.0 ips Harmonic	Confirmed by DGA & Internal Insp.	X4	$20,000
Transformer, Main Tank	Internal Vibration / Core Looseness	Critical	> 1.0 ips Harmonic	Confirmed by DGA & Internal Insp.	X4	$40,000
Transformer, Bushings	Bushings and connections	Intermediate	10 - 35 C rise	Hot Line of site or internal problem	X4	$5,000
Transformer, Bushings	Bushings and connections	Serious	36 - 75 C rise	Hot Line of site or internal problem	X4	$10,000
Transformer, Bushings	Bushings and connections	Critical	> 75 C rise	Hot Line of site or internal problem	X4	$20,000
Transformer, Control	Control Cabinet Terminal connections, heaters, Etc.	Intermediate	10 - 35 C rise	Hot Line of site Connection	X4	$1,275
Transformer, Control	Control Cabinet Terminal connections, heaters, Etc.	Serious	36 - 75 C rise	Hot Line of site Connection	X4	$2,000
Transformer, Control	Control Cabinet Terminal connections, heaters, Etc.	Critical	> 75 C rise	Hot Line of site Connection	X4	$5,000
Transformer, Cooling System	Loss of Normal Cooling, Pumps, Fans, Controls, Etc.	Intermediate	10/25% Loss	Not working / overheating	X4	$1,000
Transformer, Cooling System	Loss of Normal Cooling, Pumps, Fans, Controls, Etc.	Serious	25/50% Loss	Not working / overheating	X4	$2,000
Transformer, Cooling System	Loss of Normal Cooling, Pumps, Fans, Controls, Etc.	Critical	>50% Loss	Not working / overheating	X4	$3,000
Transformer, LTC	Load Tap Changer	Intermediate	1 - 10 C rise	Overheating with DGA confirmation		$10,000
Transformer, LTC	Load Tap Changer	Serious	11 - 20 C rise	Overheating with DGA confirmation		$25,000
Transformer, LTC	Load Tap Changer	Critical	>20 C rise	Overheating with DGA confirmation		$50,000
Transformer, LTC	Load Tap Changer	Critical		Elevated Arching detected during operation		$50,000
Transformer	Oil level below radiator intakes	Serious		Detected using IR or actual internal insp.	X4	$20,000
Transformer	Galvanized fitting causing Hydrogen Generation	Avoided		Oil Sampling	X4	$2,500
Transformer	Significant Hydran Increase			DGA Confirms Hydran	X4	$2,000
Circuit breaker, Oil	Hot Phase Tank	Intermediate	1 - 10 C rise		X4	$5,000
Circuit breaker, Oil	Hot Phase Tank	Serious	11 - 20 C rise		X4	$10,000
Circuit breaker, Oil	Hot Phase Tank	Critical	>20 C rise		X4	$20,000
Disconnects	Jaw, Hinge, Pad Connections, Etc.	Intermediate	10 - 35 C rise	Hot Line of site Connection	X4	$1,275
Disconnects	Jaw, Hinge, Pad Connections, Etc.	Serious	36 - 75 C rise	Hot Line of site Connection	X4	$2,000
Disconnects	Jaw, Hinge, Pad Connections, Etc.	Critical	> 75 C rise	Hot Line of site Connection	X4	$5,000
Miscellaneous Electrical Equip.		Intermediate	10 -35 C rise	Hot Line of site Connection	X4	$1,275
Miscellaneous Electrical Equip.		Serious	36 - 75 C rise	Hot Line of site Connection	X4	$2,000
Miscellaneous Electrical Equip.		Critical	> 75 C rise	Hot Line of site Connection	X4	$5,000
Miscellaneous Electrical Equip.		Intermediate		Miscellaneous Air Leaks	X4	$200
Oil Filled Electrical Equipment	Low oil Level	Intermediate		No Visible oil leaks	X4	$250
Oil Filled Electrical Equipment	Pegged Low	Serious		No Visible oil leaks	X4	$1,000
Oil Filled Electrical Equipment	Pegged Low	Critical		Visible oil leaks	X4	$2,000

OCCURANCE REPORT FORM

EPRI

SUBSTATION PREDICTIVE MAINTENANCE PROGRAM

OCCURRENCE REPORT

COMPANY ____________________ DATE______________

OCCURRENCE #_______________________________________

SUBSTATION____

AFFECTED EQUIPMENT____
____

LOAD:_____ VOLTAGE______________________

DESCRIPTION OF OCCURRENCE____
____
____

SEVERITY:____ INTERMEDIATE______ SERIOUS_____ CRITICAL___

RECOMMENDATION____
____
____

DETECTED BY:_____________ PERSON NOTIFIED:_____________

METHOD OF DETECTION:____

VISUAL____ DGA_____ HYDRAN__ THERMOGRAPHY______________

ULTRAPROBE 2000___ FAULT DETECTOR_______ VIBRATION _______

SUBSTATION PDM PROJECT MANAGER FOLLOW-UP

ACTION TAKEN____
____
____

COMPLETED BY:________________________ DATE: ______________________

FIELD DATA ACQUISITION FORM

M&D SUBSTATION PDM PROGRAM					
Substation			**Transformer#**		
Mfg.		Mfg. date		Oil Cap(gal)	
S/N		Load Cap.		# of Pumps	
Type		Voltage		# of Fans	

	DATE		LTC MAKE	
	AMBIENT TEMP (F)		LTC TYPE	
	LOAD (mw)		LTC DIFF. TEMP.	
	AMPS		LTC PROFILE	
	WINDING TEMP (C)		LTC TAP POSITION	
	TOP OIL TEMP (C)		LTC TAP RANGE (min/max)	
	MAIN TANK HYDRAN (PPM)		LTC TAP COUNTS	
			LTC OIL LEVEL	

TESTS PERFORMED:			
Sound Level (Y/N)		MAIN TANK DGA (Y/N)	
Vibration (Y/N)			
IR Thermography (Y/N)		LTC DGA (Y/N)	
Sonic/Ultrasonic /PD (Y/N)			
Hydran (Y/N)		OCCURRENCE (Y/N)	

Note: All pumps, coolers and data locations are identified from the High Side CCL.

► Data Locations

FIELD DATA ACQUISITION FORM

M&D SUBSTATION PDM PROGRAM					
	ULTRASONIC FD RESULTS	SIDE 1	SIDE 2	SIDE 3	SIDE 4
in air______	Average reading / High reading				
	SOUND LEVEL (db)	SIDE 1	SIDE 2	SIDE 3	SIDE 4
	PUMP DATA	PUMP 1	PUMP 2	PUMP 3	PUMP 4
	Ultrasonic				
	Sonic				
		PUMP5	PUMP6	PUMP7	PUMP8
	Ultrasonic				
	Sonic				

Date	**Notes & Occurrences**

FIELD DATA ACQUISITION FORM

M&D SUBSTATION PDM PROGRAM

Fault Detector

High Side		**LOC 1**	**LOC 2**	**LOC 3**	**LOC 4**
7'	ULTRASONIC (RMS)				
	SONIC (RMS)				
5'	ULTRASONIC (RMS)				
	SONIC (RMS)				
2'	ULTRASONIC (RMS)				
	SONIC (RMS)				

SIDE 2		**LOC 1**	**LOC 2**	**LOC 3**	**LOC 4**
7'	ULTRASONIC (RMS)				
	SONIC (RMS)				
5'	ULTRASONIC (RMS)				
	SONIC (RMS)				
2'	ULTRASONIC (RMS)				
	SONIC (RMS)				

SIDE 3		**LOC 1**	**LOC 2**	**LOC 3**	**LOC 4**
7'	ULTRASONIC (RMS)				
	SONIC (RMS)				
5'	ULTRASONIC (RMS)				
	SONIC (RMS)				
2'	ULTRASONIC (RMS)				
	SONIC (RMS)				

SIDE 4		**LOC 1**	**LOC 2**	**LOC 3**	**LOC 4**
7'	ULTRASONIC (RMS)				
	SONIC (RMS)				
5'	ULTRASONIC (RMS)				
	SONIC (RMS)				
2'	ULTRASONIC (RMS)				
	SONIC (RMS)				

Tap Changer Compartment		**LOC 1**	**LOC 2**	**LOC 3**	**LOC 4**
	ULTRASONIC (RMS)				
	SONIC (RMS)				

GENERIC DATABASE FORM

M&D SUBSTATION PDM PROGRAM		
Substation		***Transformer***
Mfg.	Mfg. date	Oil Cap(gal)
S/N	Load Cap.	Pumps
Type	Voltage	Fans
LTC Model/Type		

	DATE					
	AMBIENT TEMP (f)					
	LOAD (mw)					
	AMPS					
	WINDING TEMP (C)					
	OIL TEMP (C)					
	MAIN TANK HYDRAN (PPM)					
	LTC DIFF. TEMP.					
	LTC TEMP PROFILE					
	LTC TAP POSITION					
	LTC TAP RANGE (min/max)					
	LTC TAP COUNTS					
	LTC OIL LEVEL					
	OCCURRENCE (YES/NO)					

TESTS PERFORMED:

Sound Level (yes/no)	YES				
Vibration (yes/no)	YES				
IR Thermography (yes/no)	YES				
Sonic/Ultrasonic /PD (yes/no)	YES				
Hydran (yes/no)	YES				

Note: All pumps, coolers and data locations are identified starting on the high side counting counter clockwise.

► Data Locations

GENERIC DATABASE FORM

M&D SUBSTATION PDM PROGRAM						
Substation			***Transformer***			
	Date	1/0/00				
	SOUND LEVEL (db)					
	High Side					
	Side #2					
	Low Side					
	Side #4					
	VIBRATION LEVEL (ips)					
	High Side Left					
	High Side Right					
	Side #2 Left					
	Side #2 Right					
	Side #3 Left					
	Side #3 Right					
	Side #4 Left					
	Side #4 Right					

Date	Notes & Occurrences
1/0/00	STA/JLG

GENERIC DATABASE FORM

M&D SUBSTATION PDM PROGRAM						
Substation			***Transformer***			
	PUMP DATA					
	Pump #1 (off/on)					
	Ultrasonic					
	Sonic					
	Vibration Axial					
	Vibration Vertical					
	Vibration Horizontal					
	Pump #2 (off/on)					
	Ultrasonic					
	Sonic					
	Vibration Axial					
	Vibration Vertical					
	Vibration Horizontal					
	Pump #3 (off/on)					
	Ultrasonic					
	Sonic					
	Vibration Axial					
	Vibration Vertical					
	Vibration Horizontal					
	Pump #4 (off/on)					
	Ultrasonic					
	Sonic					
	Vibration Axial					
	Vibration Vertical					
	Vibration Horizontal					
	Pump #5 (off/on)					
	Ultrasonic					
	Sonic					
	Vibration Axial					
	Vibration Vertical					
	Vibration Horizontal					
	Pump #6 (off/on)					
	Ultrasonic					
	Sonic					
	Vibration Axial					
	Vibration Vertical					
	Vibration Horizontal					
	Pump #7 (off/on)					
	Ultrasonic					
	Sonic					
	Vibration Axial					
	Vibration Vertical					
	Vibration Horizontal					
	Pump #8 (off/on)					
	Ultrasonic					
	Sonic					
	Vibration Axial					
	Vibration Vertical					
	Vibration Horizontal					

GENERIC DATABASE FORM

M&D SUBSTATION PDM PROGRAM						
Substation			***Transformer***			
HIGH SIDE DATA						
	DATE	1/0/00				

ULTRASONIC FD RESULTS					
Reading in Air					
Average reading / High reading					

HIGH SIDE DATA LOCATION #1						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
HIGH SIDE DATA LOCATION #2						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
HIGH SIDE DATA LOCATION #3						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
HIGH SIDE DATA LOCATION #4						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					

GENERIC DATABASE FORM

M&D SUBSTATION PDM PROGRAM						
Substation				***Transformer***		
SIDE #2 DATA						
	DATE	1/0/00				

ULTRASONIC FD RESULTS					
Reading in Air					
Average reading / High reading					

SIDE #2 DATA LOCATION #1						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
SIDE #2 DATA LOCATION #2						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
SIDE #2 DATA LOCATION #3						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
SIDE #2 DATA LOCATION #4						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					

GENERIC DATABASE FORM

M&D SUBSTATION PDM PROGRAM						
Substation			***Transformer***			
SIDE #3 DATA						
	DATE	1/0/00				
ULTRASONIC FD RESULTS						
Reading in Air						
Average reading / High reading						
SIDE#3 DATA LOCATION #1						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
SIDE #3 DATA LOCATION #2						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
SIDE #3 DATA LOCATION #3						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
SIDE #3 DATA LOCATION #4						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					

GENERIC DATABASE FORM

M&D SUBSTATION PDM PROGRAM						
Substation				***Transformer***		
SIDE #4 DATA						
	DATE	1/0/00				
ULTRASONIC FD RESULTS						
Reading in Air						
Average reading / High reading						
SIDE #4 DATA LOCATION #1						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
SIDE #4 DATA LOCATION #2						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
SIDE #4 DATA LOCATION #3						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
SIDE #4 DATA LOCATION #4						
7'	ULTRASONIC (RMS)					
	SONIC (RMS)					
5'	ULTRASONIC (RMS)					
	SONIC (RMS)					
2'	ULTRASONIC (RMS)					
	SONIC (RMS)					
TAP CHANGER						
	DATE	1/0/00				
Tap Changer data location #1						
	ULTRASONIC (RMS)					
	SONIC (RMS)					

AVOIDED COST LOG

Occurrence / Avoided Cost Report Log			
Number		Date	Dollars
UTL98-001	Creek Sub - West 345 Trans. - Oil leak, B phase LTC	11/17/98	
UTL98-002	Creek Sub - West 345 Trans. - winding temp gauges need cal.	11/18/98	
UTL98-003	Creek Sub - 5701 Disc. - 137C rise on 4 hole pad	11/19/98	$5,00
UTL98-004	Creek Sub - Sta. Battery - Wet & dirty tops, corrosion on posts	11/20/98	
UTL98-005	Murry Sub - East Trans. - Oil temp. gauge is defective	11/21/98	
UTL98-006	Mill Sub - 66kv Trans. - Fan motor leads deteriorated	11/22/98	
UTL98-007	Mill Sub - 66kv Trans. -A 25C rise on fan term. block (repaired)	11/23/98	$1,27
UTL98-008	Elm Sub - South Auto - % thermal load gauge is defective	11/24/98	
UTL98-009	Elm Sub -5045 OCB Disc - A 270C rise A ph & 185C rise C ph clips.	11/25/98	$5,00
UTL98-010	Elm Sub -Sta. Battery - Wet & dirty tops, corrosion on posts	11/26/98	
UTL98-011	Trail Sub. - 132/12kv trans. - cooling system wires overheating	11/27/98	
UTL98-012	Trail Sub. -4843 Disc. - An 87C rise on B ph clip	11/28/98	$5,00
UTL98-013	Lane Sub - Station Battery - Wet & dirty, Battery grounded	11/29/98	
UTL98-014	Shell Sub. - South Trans. - Abnormal Vibration	11/30/98	
UTL98-015			
UTL98-016			
UTL98-017			
UTL98-018			
UTL98-019			
UTL98-020			
UTL98-021			
UTL98-022			
UTL98-023			
UTL98-024			
UTL98-025			
UTL98-026			
UTL98-027			
UTL98-028			
UTL98-029			
UTL98-030			
UTL98-031			
UTL98-032			
UTL98-033			
UTL98-034			
UTL98-035			
UTL98-036			
UTL98-037			
UTL98-038			
UTL98-039			
UTL98-040			
	Note: The avoided cost figures are from the generic cost key.		
	The other occurrences must be done using the avoided cost work sheets.		
	See the work sheet for an example		

1234 Old Mill Ave.
Downtown, USA 123456

Dear Mr.Doe:

Attached is the Substation Predictive Maintenance Report for surveys performed during the week of April 1, 2001. This report identifies the troubled equipment and provides a description of the conditions detected.

An executive summary of the severity of the anomalies detected at each location is included in the attached report. If you require any further information or have any questions concerning this report please contact me at the 610/490-3227.

Sincerely,

George Spencer, Manager
Substation Diagnostic Group

cc:

J. Smith	PL&P
J. Jones	PL&P
J. Mills	PL&P (5)
Woyshner	M&D
P. Dessureau	EPRI
File	(2)

M&D/PL&P SUBSTATION
PREDICTIVE MAINTENANCE SURVEY REPORT
April, 2001

Executive Summary Substation Predictive Maintenance Survey April, 2001

All transformers and associated switchyard equipment at five locations were surveyed. Twenty-four anomalies were reported as occurrences.

- 3 critical
- 11 serious
- 10 intermediate

Dow Substation Four anomalies were reported as occurrences

1 CRITICAL
2 SERIOUS
1 INTERMEDIATE

See Additional Comments

Manhattan Ferry Substation Two anomalies were reported as occurrences

1 SERIOUS
1 INTERMEDIATE

See Additional Comments

North Substation Four anomalies were reported as occurrences

1 CRITICAL
3 INTERMEDIATE

See Additional Comments

Smith Island Substation Seven anomalies were reported as occurrences

1 CRITICAL
3 SERIOUS
3 INTERMEDIATE

See Additional Comments

South Substation Seven anomalies were reported as occurrences

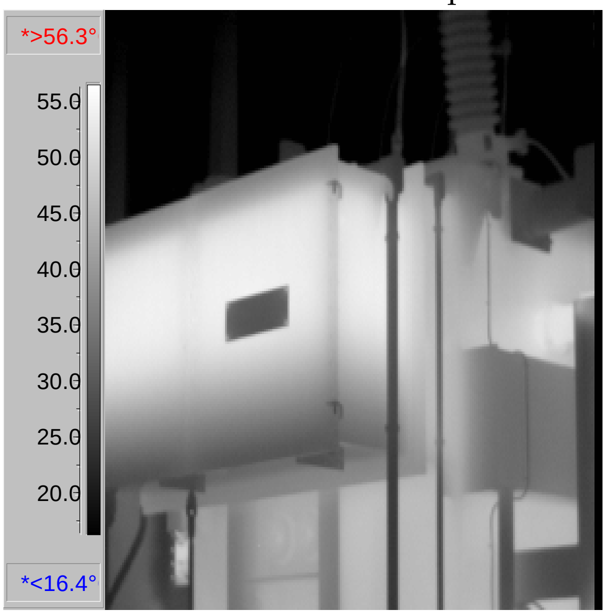
5 SERIOUS
2 INTERMEDIATE

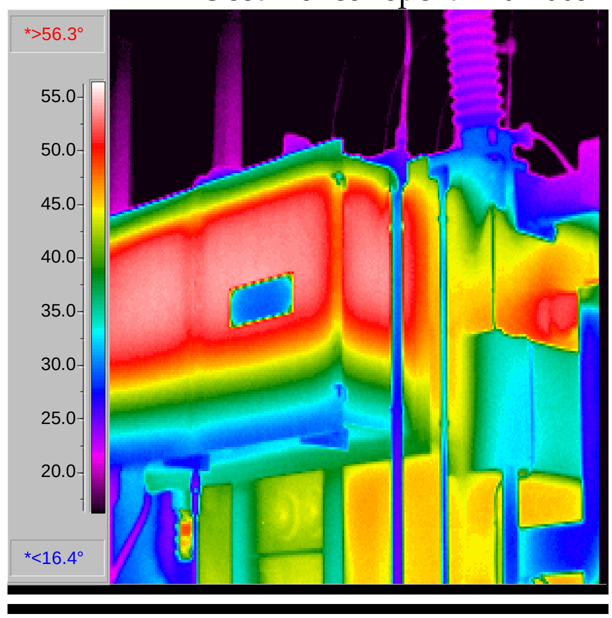
See Additional Comments

For detailed information concerning these occurrences, and other findings, please refer to the troubled equipment list and the comments sections of this report.

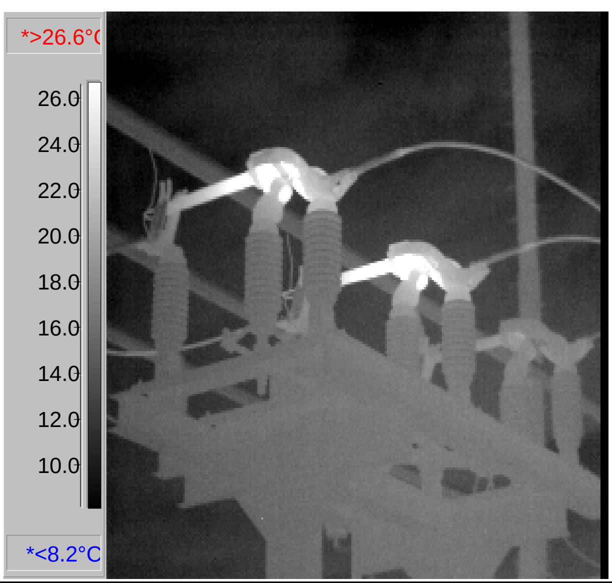
EQUIPMENT STATUS
Troubled Equipment List

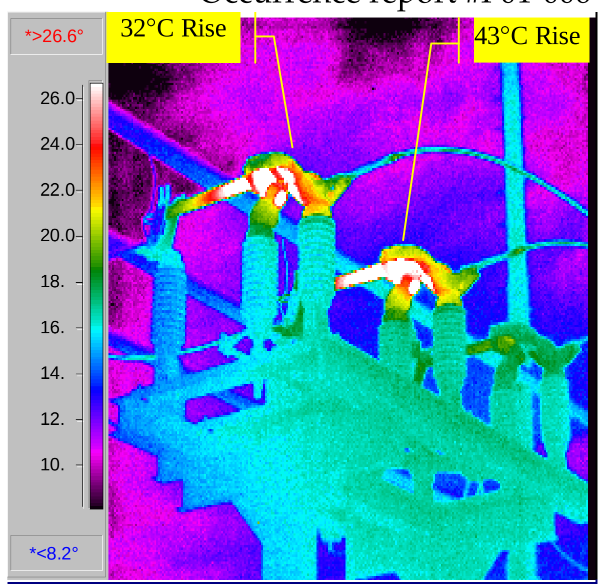
Substation	Survey Date	Status
Manhattan Ferry Substation		
	April 3, 2001	**SERIOUS**
23kV Transformer	A 9°C temperature rise was detected on the load tap changer compartment. Occurrence report #P01-005	





	April 3, 2001	**INTERMEDIATE**
#22549 Bus Disconnect	A 32°C temperature rise was detected on A∅ jaw and a 43°C rise on B∅ jaw. Occurrence report #P01-006	



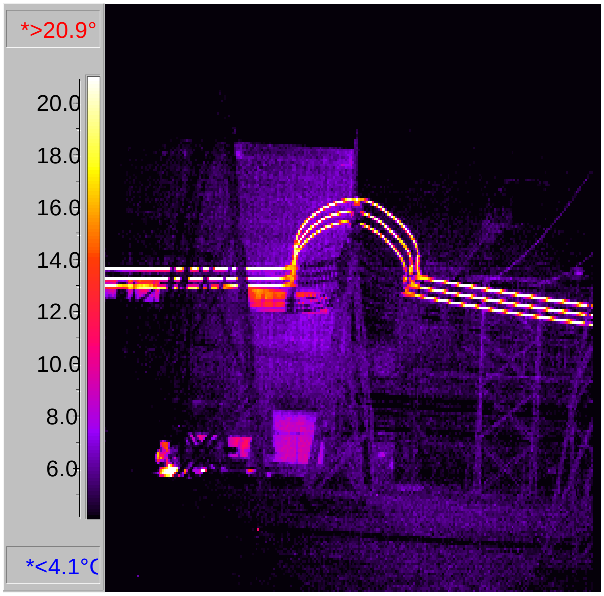


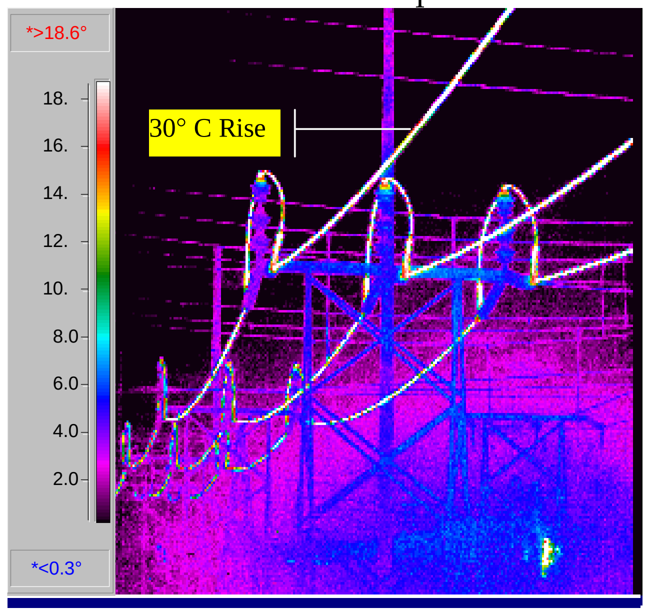
Smith Island Substation (continued)

138kV #2 Bus — **April 1, 2001** — **INTERMEDIATE**

A 30° C temperature rise was detected on all three phases of the bus, indicating an overload situation on this section of bus.

Occurrence report #P01-015





23kV Bus PT — **April 1, 2001** — **CRITICAL**

The C∅ PT is pegged low on oil and has had a failure which bulged the tank without a rupture. The primary fuse is blown.

Occurrence report #P01-016

Network Feeder PT — **April 1, 2001** — **SERIOUS**

The A∅ & B∅ PT's are pegged low on oil.

Occurrence report #P01-017

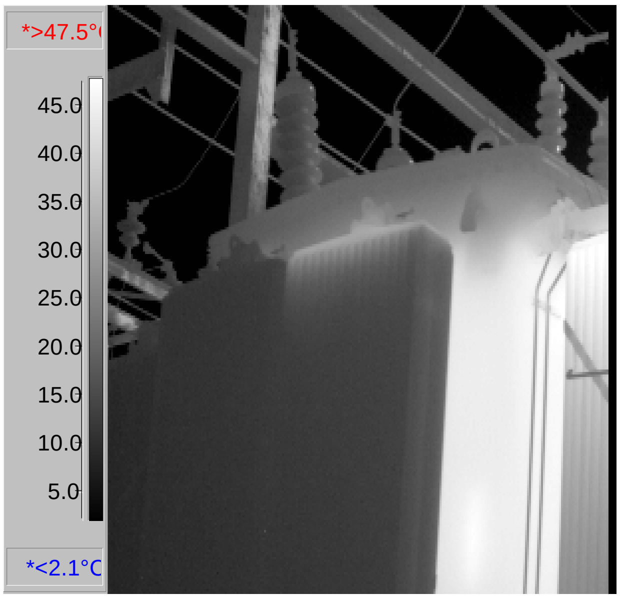
South Substation

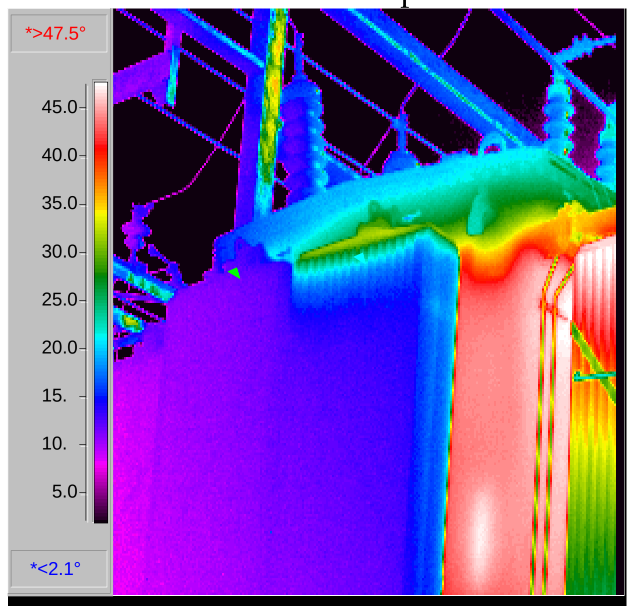
#22 Transformer

April 2, 2001 **SERIOUS**

The main tank is low on oil. The oil is only circulating through the low side (side #3) radiators and one of the side #2 radiators.

Occurrence report #P01-022





#2 Auto Transformer

April 2, 2001 **SERIOUS**

The station service transformer oil level is pegged low. The Hydran results indicate a significant increase from 51ppm to 142ppm. A dissolved gas analysis (DGA) is suggested to determine the levels of all combustible gasses in the oil.

Occurrence report #P01-023

Z63 Circuit Breaker

April 2, 2001 **SERIOUS**

BØ Tank is pegged low on oil.

Occurrence report #P01-024

SUBSTATION SURVEY

Additional Comments

(April 2001 Report)

Location	***Comments***
Dow	**2A 138 kV Transformer**
	One fan on cooler #1 is not working.
	Z 28 Line PT
	There is an active oil leak coming from the C∅ ground bushing
Manhattan	**231 Circuit Breaker**
	The A∅ tank is low on oil
North	**69 kV Bus Tie Transformer**
	An oil leak was observed on the left, high side corner of the main tank.
23 kV PT	
	The oil level gauge on the B∅ and the C∅ PT read low.
	23 kV Bank Breaker
	A 5°C temperature rise was detected on the C∅ bushing connector on the transformer side.
Smith Island	**138 kV Transformer**
	There is an active oil leak in the LTC cabinet coming from the tap changer shaft linkage
South	**#2 Auto Transformer**
	The bottom outside fan on cooler #2 is not working. An oil leak was observed on the left radiator on the station service transformer. The B∅ and the C∅ low volt bushings on the transformer are low on oil.

A 6°C temperature rise was detected on the load side connection on the breaker

* SEVERITY CRITERIA *

INFRARED THERMOGRAPHY

For line of site electrical connections

Temperature Rise referenced from like equipment, not ambient

Critical................................75°C or greater
Serious ....35°C - 75°C
Intermediate.........................10°C - 35°C
Minor................................... < 10°C

All other electrical and mechanical severity are determined by equipment condition and operator experience.

CORONA / PARTIAL DISCHARGE (AE EVENTS)

Events / Counts per Second = (event rate)

Any event rate needs to be investigated. When significant increases in ultrasonic RMS levels occur on a transformer, or odd activity is detected,
a portable gas in oil analysis and a DGA should be performed. Further investigation to source locate the activity, using on-line PD equipment, should be performed.
Severity is determined by operator experience.

PORTABLE GAS IN OIL

Parts per Million (PPM)

When significant increases occur on a trended transformer, or a baseline can not be established on a new transformer. The criteria for PD/AE events should then be used in conjunction with DGA and portable gas in oil analysis

SOUND LEVEL

Decibel (db)

Sound level readings are in need of further investigation when any octave bandwidth increases by 3 db or the overall level increases by 6 db.

* SEVERITY CRITERIA *

VIBRATION

Inches / Second (ips)
Transformers, Pumps, Fans & Piping

Critical 1.0 in/sec or greater
Serious .50 in/sec - 1.0 in/sec
Intermediate .25 in/sec - .5 in/sec
Minor .10 in/sec - .25 in/sec

LOSS OF FORCED AIR COOLING

Percent of Loss	Severity
Critical	50% or Greater
Serious	25% to 50%
Intermediate	10% to 25%
Minor	< 10%

LOW OIL LEVELS IN ELECTRICAL EQUIPMENT

Critical	Pegged low with signs of leakage
Serious	Pegged low
Intermediate	Low with signs of leakage
Minor	Low level

The Severity Criteria has been developed as a guide to determine the severity of a condition detected during a substation survey. Although this information may be accurate for some equipment, acceptable conditions can only be determined relative to equipment design and operation.

The Action Plan has been developed as a guide for steps toward corrective action following the detection of an anomaly during a substation survey. This Action Plan is to be implemented in conjunction with the Severity Criteria.

ACTION PLAN

Minor Problem	*Repair as part of regular maintenance; little probability of physical damage.*
Intermediate Problem	*Schedule repair. Monitor condition relative to load. Inspect for physical damage. PDM submit written report.*
Serious Problem	*Repair in the immediate future. Periodically monitor until repaired. PDM alerts supervision and submits written report.*
Critical Problem	*Repair immediately. PDM alerts supervision and submits a written report.*

Substation PDM — *Chronological Data Sheet*

Substation	P.D. Sonic Ultrasonic		Portable Gas in Oil		Thermography		Sound Level		Vibration Level	
Dow #1 Transformer	4/1/01		4/1/01		4/1/01		4/1/01		4/1/01	
Dow #2 Transformer	4/1/01		4/1/01		4/1/01		4/1/01		4/1/01	
Dow #3 Transformer	4/1/01		4/1/01		4/1/01		4/1/01		4/1/01	
Dow #4 Transformer	4/1/01		4/1/01		4/1/01		4/1/01		4/1/01	
Manhattan #1 23kv	4/3/01		----------		4/3/01		4/3/01		4/3/01	
Manhattan #2 23kv	4/3/01		----------		4/3/01		4/3/01		4/3/01	
North 69 kv bus tie Transformer	4/2/01		4/2/01		4/2/01		4/2/01		4/2/01	
North 1A Transformer	4/2/01		4/2/01		4/2/01		4/2/01		4/2/01	
North 1B Transformer	4/2/01		4/2/01		4/2/01		4/2/01		4/2/01	
North 1C Transformer	4/2/01		4/2/01		4/2/01		4/2/01		4/2/01	
North 2A Transformer	4/2/01		4/2/01		4/2/01		4/2/01		4/2/01	
North 2B Transformer	4/2/01		4/2/01		4/2/01		4/2/01		4/2/01	
North 2C Transformer	4/2/01		4/2/01		4/2/01		4/2/01		4/2/01	
North #3 Transformer	4/2/01		4/2/01		4/2/01		4/2/01		4/2/01	
North #4 Transformer	4/2/01		4/2/01		4/2/01		4/2/01		4/2/01	
Smith Island #1 Transformer	4/1/01		4/1/01		4/1/01		4/1/01		4/1/01	
Smith Island #2 Transformer	4/1/01		4/1/01		4/1/01		4/1/01		4/1/01	
Smith Island #1 Auto Transformer	4/1/01		4/1/01		4/1/01		4/1/01		4/1/01	
Smith Island #2 Auto Transformer	4/1/01		4/1/01		4/1/01		4/1/01		4/1/01	
South #22 Transformer	4/2/01		4/2/01		4/2/01		4/2/01		4/2/01	
South #33 Transformer	4/2/01		4/2/01		4/2/01		4/2/01		4/2/01	
South #2 Auto	4/2/01		4/2/01		4/2/01		4/2/01		4/2/01	

Occurrence Report / Avoided Cost Report Log			
Number		Date Sent	Benefit
01-001	Dow Substation - #242 circuit breaker, pegged low on oil	4/1/01	$1,500
01-002	Dow Substation - #1 transformer, control cabinet heaters not working	4/1/01	$1,275
01-003	Dow Substation - #2 transformer, pressure/vacuum gauge pegged on +10 lbs.	4/1/01	$2,000
01-004	Dow Substation - Z41 line PT, B & C phase pegged low on oil w/ leakage	4/1/01	$2,000
01-005	Manhattan Sub - 23 kV transformer, 9 deg. C rise on LTC	4/1/01	$10,000
01-006	Manhattan Sub - 22549 bus disc., 23 & 43 deg. C rise on A & B phase jaw	4/1/01	$1,275
01-007	North Substation - 323 bus disc., 16 deg. C rise on the center phase jaw	4/1/01	$1,275
01-008	North Substation - Z20 CB, 30 deg. C rise on the #3 bushing	4/1/01	$1,275
01-009	North Substation - #1, 23kV bus, 21 deg. C rise in A phase cable strands	4/1/01	$5,000
01-010	North Substation - 69 kV bus tie trans., 11% reduced cooling capacity	4/1/01	$1,000
01-011	Smith Island Sub - #118 disconnect, 40 deg. C rise on the A phase jaw	4/1/01	$2,000
01-012	Smith Island Sub - #112 disc., 47 & 28 deg. C rise on the C & A phase jaw	4/1/01	$2,000
01-013	Smith Island Sub - #212 CB, 20 deg. C rise on the #6 bushing	4/1/01	$1,275
01-014	Smith Island Sub - #4 trans, 17 deg. C rise on the B phase low side bushing	4/1/01	$1,275
01-015	Smith Island Sub - 138kV #2 bus sec., 30 deg. C rise on all three phases of bus	4/1/01	$1,275
01-016	Smith Island Sub - #3 23kV bus PT, C phase pegged low on oil w/signs of failure	4/1/01	$2,000
01-017	Smith Island Sub - network feeder PT, A&B phase PT pegged low on oil	4/1/01	$1,000
01-018	South Substation - 322 CB, 11 deg. C rise on B phase tank	4/2/01	$10,000
01-019	South Substation - 23681 line air break sw., 27 deg. C rise on B phase hinge	4/2/01	$1,275
01-020	South Substation - #6 trans., 22 kV fuse, 20 deg. C rise on fuse clip	4/2/01	$1,275
01-021	South Substation - 2A cap. bank, 50 deg. C rise on A phase fuse & bushing	4/2/01	$2,000
01-022	South Substation - 22 transformer, low on oil, not circulating in coolers	4/2/01	$2,000
01-023	South Substation - #2 auto trans., SS trans. pegged low on oil, increase in PPM	4/2/01	$2,000
01-024	South Substation - Z63 CB, B phase tank is pegged low on oil	4/2/01	$1,000
01-025			
01-026			
01-027			
01-028			
01-029			
01-030			
01-031			
01-032			
01-033			

01-034			
01-035			
01-036			
01-037			
01-038			
01-039			
01-040			
01-041			
01-042			
01-043			
01-044			
01-045			
01-046			
	TOTAL BENEFIT TO DATE		$56,975

C

THERMOGRAPHY COMPONENT IDENTIFICATION

Substation component identification for infrared thermographers

Jon L. Giesecke

Maintenance & Diagnostics
440 Baldwin Tower
Eddystone, PA 19022
(610) 490-3228
(800) 745-9981

ABSTRACT

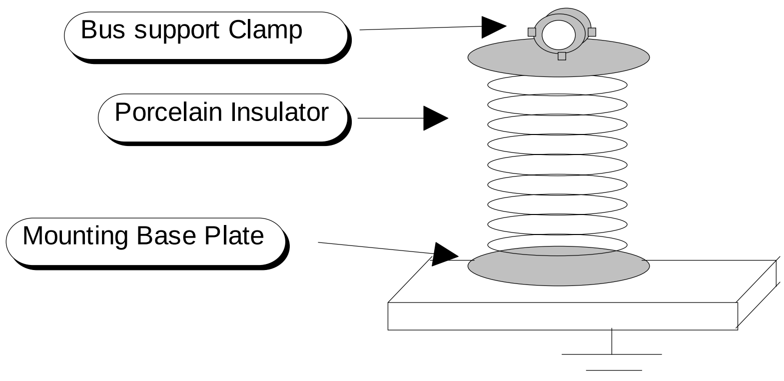
Proper training and a full understanding of substation components are necessary to effectively perform IRT surveys and analysis of components in high voltage substations. Most thermographers cannot be expected to have extensive substation equipment and operations knowledge. Therefore, this paper and tutorial presentation are designed to aid the thermographic community with the identification and the expected thermal signatures from these components. Technologies complementary to IR are also included in this presentation. Equipment discussed in this paper will be transformers and their cooling systems, load tap changers, circuit breakers, potential transformers, current transformers, lightning arresters, bushings, and standoff insulators.

Keywords: substation component identification, thermal signatures

UNDERSTANDING SUBSTATION COMPONENTS

It became very evident to me as I visited various utilities, and worked with their thermographers, that there was a need for more training in specific substation components, their applications and thermal signatures. This revelation was reinforced during a meeting of 60 infrared thermographers. They traveled from all parts of the United States to attend an Infrared Users Group meeting. An image was projected on the screen as the speaker talked about a bushing problem that he had recently detected. All heads were nodding and several theories were being bantered about; but, when I found the opportunity, I revealed to the group that the bushing being discussed was actually a lightning arrester. I then explained the difference between bushings and lightning arresters and how a lightning arrester worked. Since that time I have developed a four-hour training course for IR thermographers who have limited substation experience. The following paper describes some unique characteristics of the most common switchyard components, and how to better analyze switchyard IR survey results.

STANDOFF INSULATORS



***Function**:* The function of the standoff insulator is to keep the high voltage conductor mounted in the proper configuration according to the engineering design of the substation, insulating the high voltage source from going where it is not wanted. This means maintaining the proper distance from the ground plane (the grounded structure on which the insulator is mounted) and proper distance from the other phases. Remember that high voltage has a very strong attraction to ground, and to adjacent phases.

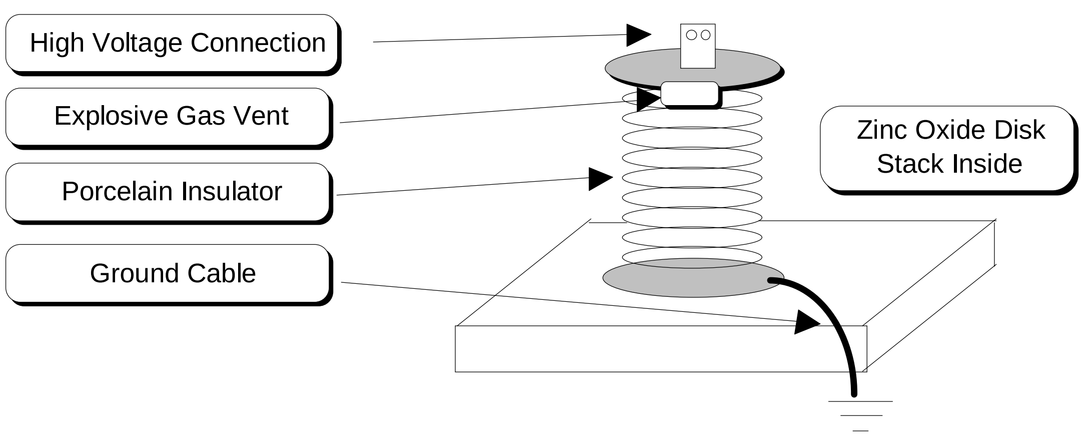
The design and materials of the standoff insulator are very important to support these functions. First it must be realized that there is no perfect insulation. Voltage and current can pass though all forms of insulation; but, if the type, amount and condition of the insulation are all correct for the voltage, the leakage will be minimal.

***Unique Characteristics**:* Notice the physical characteristics of the standoff insulator, which consists a section of porcelain mounted between a base plate and a top mounting plate. The base plate is ground potential and the top mounting plate is equipped with bus support hardware. Several names have been used to refer to the porcelain sections: rainsheds, skirts or petticoats are the most common terms used to describe these insulators because of their shape. The porcelain is formed into these shapes to help shed rain water and other environmental contaminants. Environmental contamination may cause the occurrence of ‘tracking’ (conducting paths over the insulation surface to ground), or ‘corona’ (the glow or brush discharge around conductors when the air is stressed beyond its ionization point without developing flashover). These conditions will, over time, actually etch tracks in the porcelain where the leakage is occurring; and, if left unchecked a flashover failure may occur. The shape of the petticoats also minimizes the physical area needed to properly insulate against leakage to ground. For instance, a four-foot tall standoff insulator has the insulating effect of more than ten feet of insulation, due to the surface area of each petticoat. This allows the voltage to dissipate from the original potential to zero, before it reaches the ground plane. (This concept applies to all high voltage porcelain components.) The term disk should never be used when referring to the porcelain sections of standoff insulators or bushings. Using the term “disk” could be confused with a component of a lightning arrester.

***IR Analysis**:* The normal thermal signature of a standoff insulator is ambient. The most common anomaly involves cracked porcelain, where moisture has penetrated the outer glaze of the porcelain. The IRT image would appear as a hot spot as current leaks to ground. However, in a below freezing environment the current flow may not occur, because ice is an excellent insulator and does not track or flashover. Another common anomaly is the problem of environmental contamination or just plain dirt.

The dirt may look like a hot spot, but be only an emissivity difference; or, the dirt may be conductive in nature and actually be passing current to ground. Not all tracking conditions are detectable using IRT. If heat is not generated by a tracking condition, ultrasonic noise analysis may have to be used to detect the anomaly. Ultrasonic noise analysis is a complementary testing method when performing switchyard infrared surveys.

LIGHTNING ARRESTERS

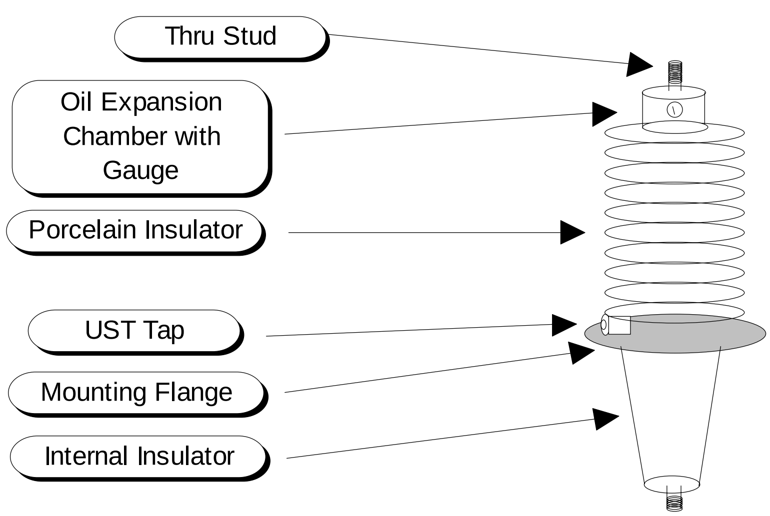


Function: Lightning arresters (LA’s) protect electrical equipment from damaging surges from lightning. The location of an LA in the circuit will help to distinguish it from similar looking components, such as standoff insulators. The LA is usually connected to the bus with a section of cable that provides no physical support of the bus. It is usually the first component in the circuit. In other words, when an incoming line enters a substation yard, the first component on that line is usually the LA. The same holds true for the incoming lines to a transformer.

Unique Characteristics: Physically, LA's look similar to a standoff insulator, but with several minor differences. The LA has a large ground cable connected at the bottom and it runs down the structure that connects to the station ground. Sometimes a fault meter is installed in this ground cable to record any lighting-to-ground events. The most common style LA has a stack of zinc oxide disks inside the LA which are insulated from each other under normal voltage conditions. During a lighting surge the insulation momentarily breaks down, passing the lightning safely to ground. This type of LA usually has an unusual shape to the top cap, which is a vent that allows potentially dangerous explosive gasses created during a lightning surge to escape. Another type of LA is a gap arrester. This type LA consists of a series of gaps, where a surge of lightning sparks across the gaps and then travels safely to ground.

IR Analysis: The normal thermal signature is ambient. When there is an unwanted electrical flow to ground due to internal deterioration, the flow to ground will cause slight to moderate heating of the internal disks. This heat is transferred to the outer porcelain. As the condition progresses over time, the LA will eventually fail catastrophically. Usually a catastrophic failure causes the top of the LA to blow off and the metallic disks to be scattered over the surrounding area. When any temperature rise exists, the seals should be inspected for signs of deterioration, and a thorough cleaning and power factor test should be performed. Caution: Dangerously high gas pressures can accumulate within sealed-type arresters or gap units; therefore, care should be exercised when handling units suspected of internal damage.

BUSHINGS



Function: A bushing is a component that allows electricity to enter an electrical device safely, preventing it from going to ground or shorting to another phase. It is designed to seal out the environment and seal in the oil, gas etc. Again, environmental contamination may cause tracking or corona to occur.

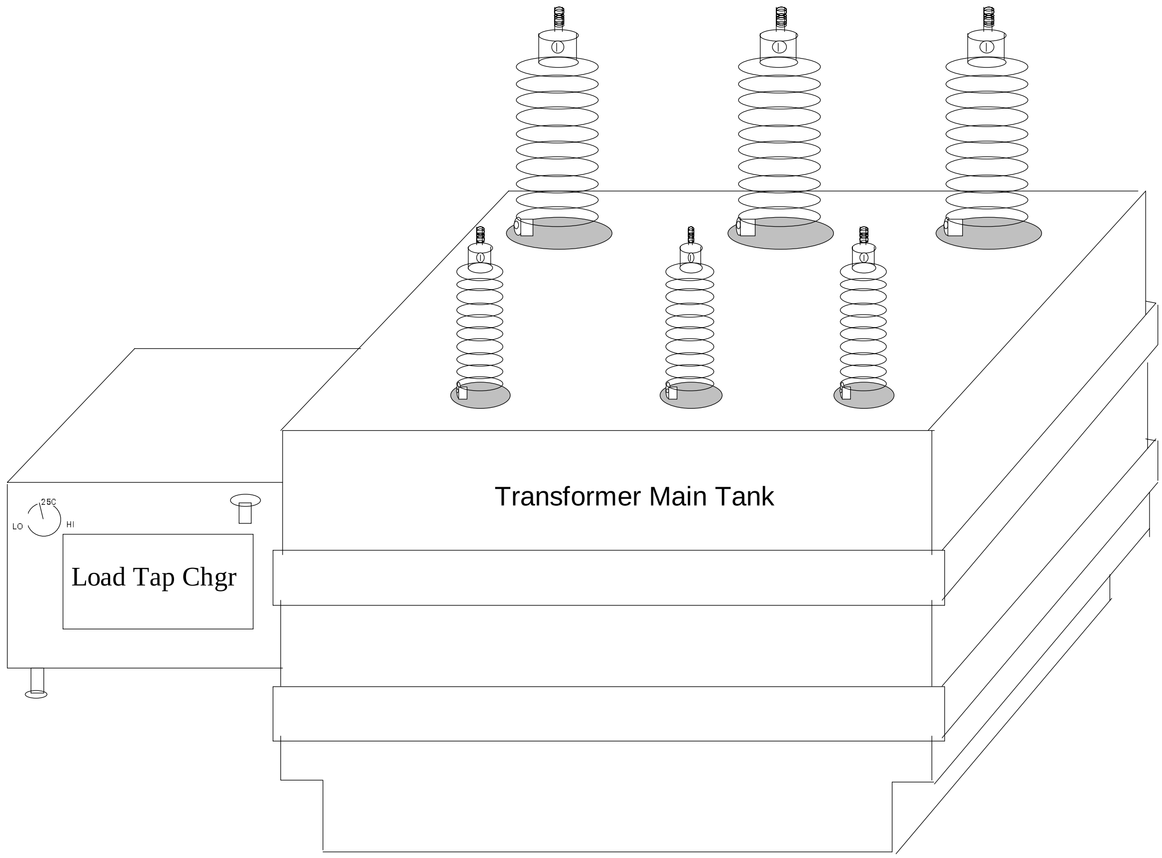
Unique Characteristics: There are many types of bushings: dry solid porcelain, compound filled, oil filled, gas filled, etc. The most common high voltage type of bushing is the oil filled bushing. Checking the oil level is of utmost importance, and this is usually done visually. However, many bushing oil leaks occur on the inside, where the oil from the bushing leaks down into the breaker or transformer and no visible leaks are evident. A loss of oil could cause a catastrophic failure of the bushing and also the transformer or circuit breaker in which the bushing is mounted.

IR Analysis: The normal thermal signature is ambient. The most common IR anomaly is a high resistance connection at the top of the bushing, either in the pad or bushing adapter. The adapter is a separate piece that screws on to the main stud, and looks like a larger version of the main stud. Be aware that the adapter-to-stud connection can fault and cause heating. A micro ohm reading can be taken to pin-point the high resistance and to confirm the repair.

Under certain conditions it is possible to detect the oil level in the oil expansion chamber using IRT, but almost impossible when the level drops into the porcelain area. The oil expansion chamber is on the top of the bushing in which an oil gauge or site glass is located. In some bushings there are connections inside the oil expansion chamber that may fault and cause heating inside the chamber.

Some bushings are made with epoxy insulators rather than porcelain, and still others are made to be self cleaning. The self cleaning bushings will sometimes heat slightly. Always be aware that these different materials may have different emissivity values.

LOAD TAP CHANGER (LTC)



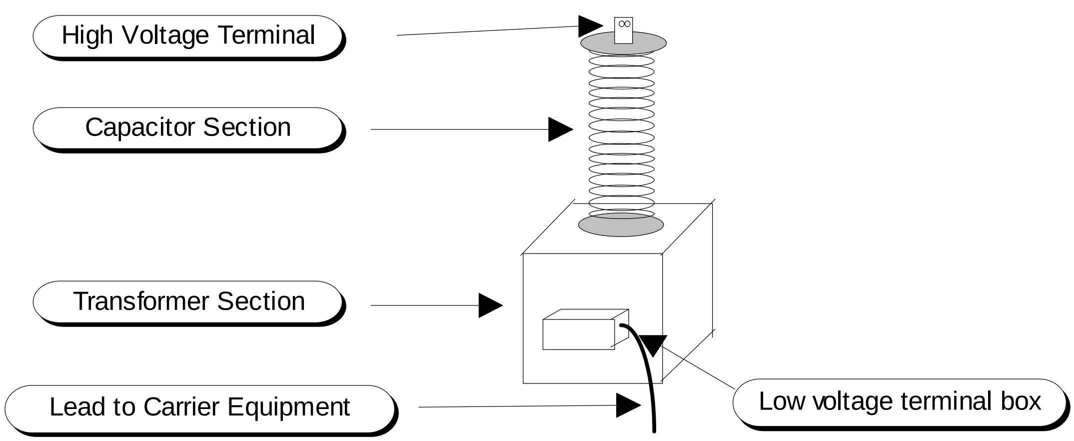
Function: As the system load changes, the load tap changer (LTC) changes tap position which changes the voltage output of the transformer. This maintains the proper operating voltage to the system being fed. Consider the LTC to be an oil circuit breaker that gets an enormous amount of work. It is driven by a motor and mechanical linkage. In most cases the motors are in an adjacent cabinet; but, in some of the older units the motors are located inside the LTC compartment and are operated completely submerged under the oil.

Unique Characteristics: An LTC is a set of movable and stationary contacts that are enclosed in a separate compartment and attached to the main tank of a transformer. The LTC compartment is oil filled and either vented to the atmosphere, sealed or gas blanketed. Flexible leads from the transformer section enter the LTC compartment through holes in an insulated board between the two compartments. The holes have oil seals around the cables to keep the LTC oil separate from the main tank oil. These seals can be damaged by heat and will allow leakage of oil between compartments. The cables connect the transformer winding to the LTC. Some of the newer LTCs have the contacts contained inside vacuum bottles; however, the main problems occur with the older mechanical type mechanisms. In the past, the manufacture’s recommendation for maintenance was the only method used to maintain the LTCs. Many LTCs were opened for routine maintenance and found to be in perfect condition, while other LTCs were failing between scheduled overhauls.

The Maintenance & Diagnostics Inc's. Substation PDM program was developed to address this type of problem. With the M&D program, five different tests are combined to determine the overall on-line condition of the LTC. IRT is the only test method that can be discussed here, due to the proprietary nature of the other tests.

IR Analysis: Any heat present in the LTC compartment is conducted through the insulation board from the transformer section of the unit. Under normal conditions the LTC compartment will be 5°C to 10°C cooler than the main tank at the same elevation. Even a 1°C rise should be investigated. The LTC is not a heat source under any load condition.

COUPLING CAPACITOR

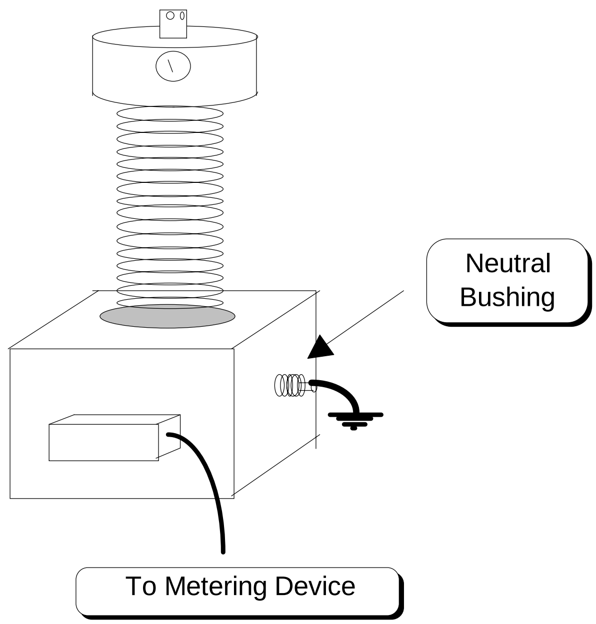


Function: In most new substations, coupling capacitors, or capacitive coupling voltage transformers (CCVTs), are used instead of wound potential transformers, because this device can double as a potential transformer (voltage reference) and a power-line carrier coupling device. Power-line carrier has traditionally been used for teleprotection, but it is also used for both data and voice transmissions. The coupling capacitor is a device used in conjunction with a wave trap and line tuner, these devices are used to confine and capture the transmission signal and provide matching impedance to the transmission line. The carrier terminal equipment injects and recovers the telecommunications signal onto and from the phase or neutral wire via the coupling capacitors and line tuners. Wave traps are connected in series with the power line, between the coupling capacitor and the substation.

Unique Characteristics: The major elements consist of a series of capacitors in the upper bushing housing, sealed but not oil filled. The lower section contains the transformers. Some are dry type air only compartments and others have sealed oil design. The oil filled transformer sections usually have a site glass to check oil levels.

IR Analysis: The transformer sections are normally just above ambient. The capacitor section is just above ambient and slightly warmer at the top of the porcelain. Compare results with other units in the same circuit and load condition.

POTENTIAL TRANSFORMER (PT) OR POTENTIAL DEVICE (PD)

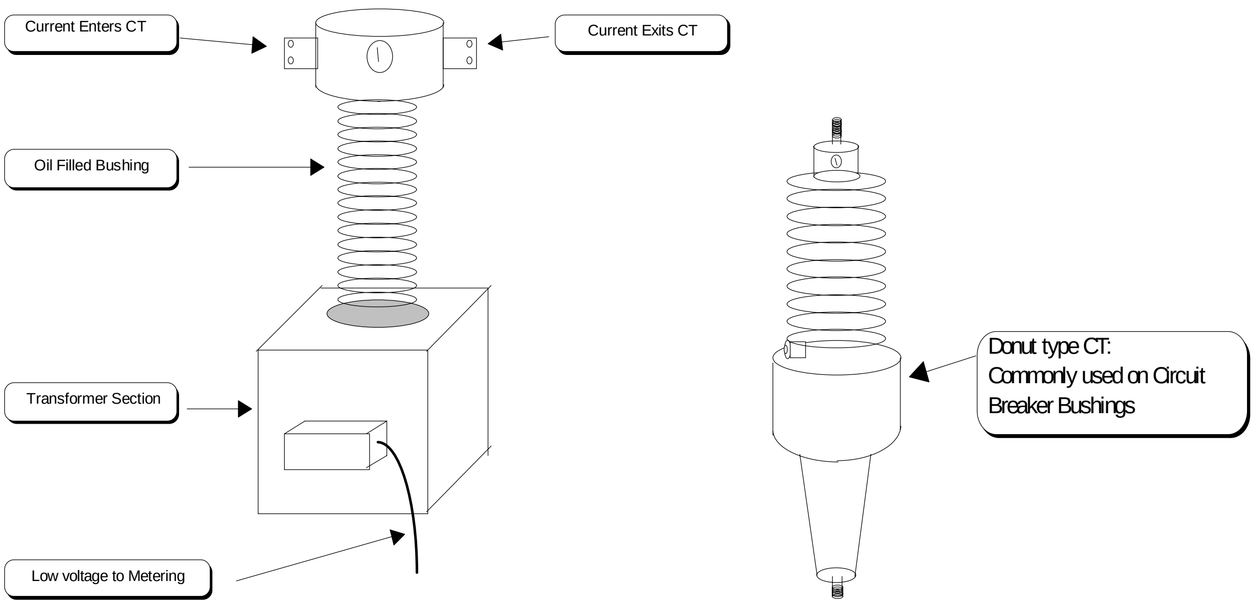


Function: To measure and provide a method for obtaining the voltage value from a high voltage line or bus. The transformer steps down the high voltage to normal metering voltage.

Unique Characteristics: Normally, the bushing and transformer section are oil filled with no seal between them. The bushing section contains a thin wire that runs from the top connection down to the transformer section. The bottom housing contains the step down transformer. The one major problem with these units is oil leaks. The leaks are normally very slight and can take many years to have any adverse effects. But what takes place over these years of leakage is a total loss of oil in the bushing section. When the oil level reaches the grounded bushing entrance opening, the high volt lead arcs to ground, causing a catastrophic event. The units normally have an oil gauge or site glass that are easily overlooked. The other telltale sign to look for is an oil stain under the equipment. This would indicate a long term leak and a potential failure.

IR Analysis: The transformer section is normally just above ambient. The bushing section is usually ambient. Compare with other units in the same circuit and load condition.

CURRENT TRANSFORMER (CT) ...TWO TYPES

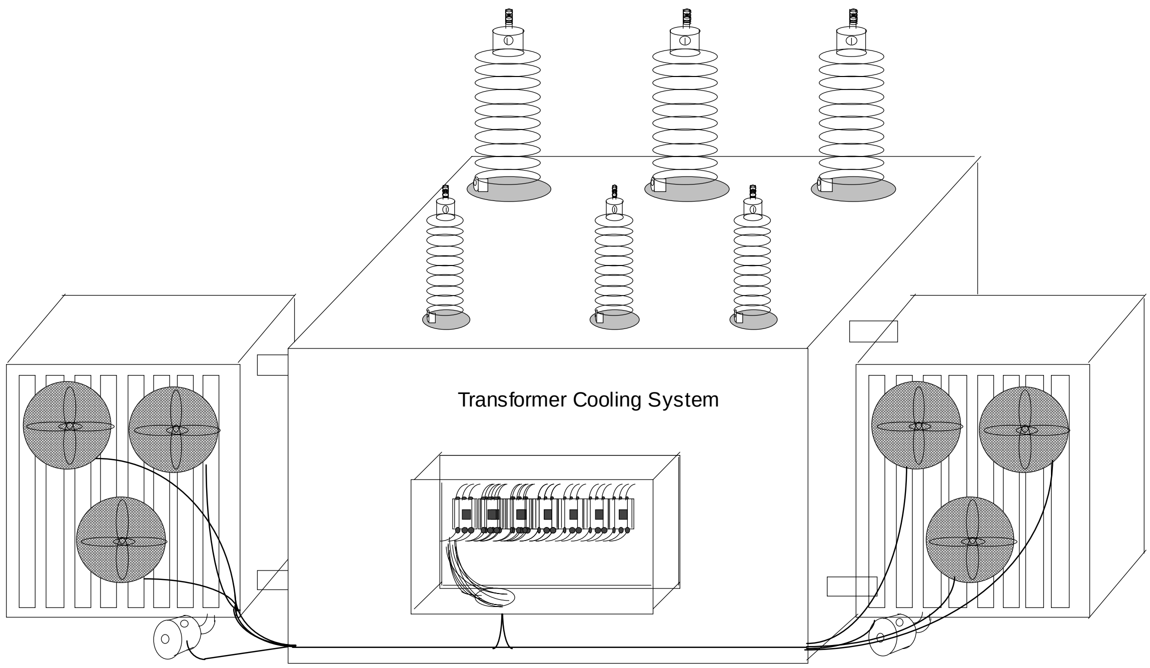


Function: To measure and provide a method for obtaining the current or amp value from a high voltage line, bus or circuit breaker.

Unique Characteristics: There are many configurations for CTs, but for this discussion only two types will be discussed: the free standing oil filled type and the bushing donut type. Normally, a free standing CT is oil filled completely to the top of the bushing. The bushing section contains a heavy current carrying conductor that runs from one of the top connections down through the center of the transformer and back up to the other terminal, which comprises a complete flow-through of the current. The bottom housing contains the step down transformer. As with the PTs, the oil leakage problem holds true for these CTs as well. The bushing donut type CT is a solid compound-filled winding and is not subject to oil leakage.

IR Analysis: The transformer section is normally just above ambient when lightly loaded, and as much as 15°C above ambient when at full load condition. The bushing section is usually ambient. Compare with other units in the same circuit and load condition.

TRANSFORMER COOLING SYSTEM



Function: To maintain and regulate the proper cooling for the main winding section of a transformer.

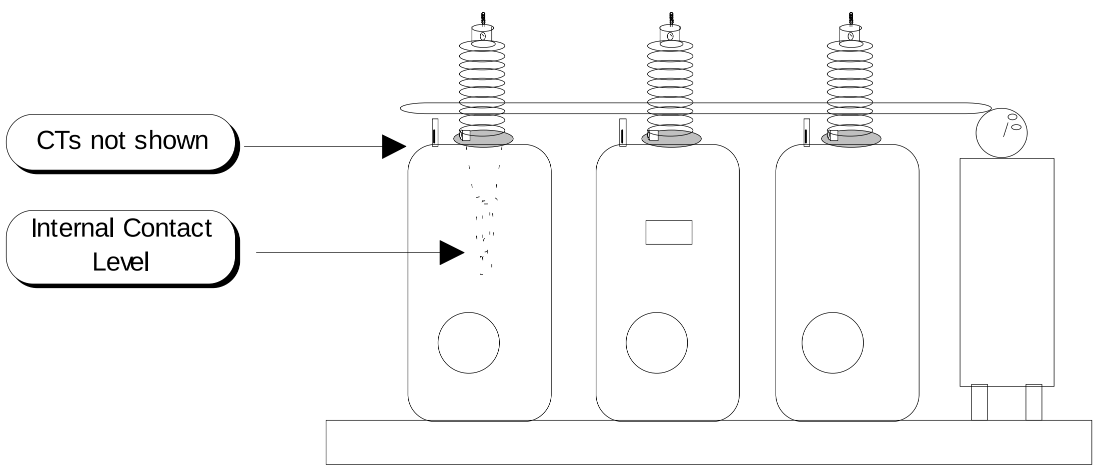
Unique Characteristics: There are several different cooling system configurations. OA/FA/FOA/FOW are some of the abbreviations found on transformer nameplates. OA stands for Oil/Air: This means the cooling system uses oil to air for the transfer of heat energy without the use of pumps or fans. FA or Forced Air means that the cooling is aided by fans, but without any pumps to circulate the oil. With both of these systems the oil circulates through the radiators or heat exchangers by normal convection only. The oil flow path through all transformer cooling systems is; into the radiator on the top and discharge back into the main tank on the bottom. FOA or Forced Oil and Air mean that the system uses both pumps and fans for the cooling of oil. FOW or Forced Oil and Water means that the heat exchanger on this type is water cooled and does not have the typical radiator configuration. The cooler is normally a chamber with many tubes inside where the oil and water exchange heat energy. Some of the older FOWs had the water cooling tubes running inside the main tank. This works well, but the repair of leaks can be difficult.

IR Analysis: Approximately 70% of the cooling takes place in the top one-third of the radiator. A gradual cooling pattern will be evident from the top to the bottom of the radiator. Look for abnormal conditions such as: a cold radiator, indicating low oil in the unit; a blockage; or a closed valve or a pump that is not circulating oil. When possible, turn on all fans and pumps and allow them run for at least 15 minutes prior to the IR scan. This allows the motors, bearings, and control system to come up to operating temperature. At that time check the wiring, connections and all electrical components in the control cabinets. A loss of cooling can shorten the life of a transformer or cause a catastrophic failure.

A common problem that is usually overlooked is cooling fans operating in reverse. Feel for the direction of air flow and compare the temperature of the discharge air through the radiators. Over time, the cooling fins will build up dirt and other contaminants which hinders the cooling process. Measure the inlet temperatures compared to the outlet temperatures of each radiator. This will help to determine that proper heat exchange is occurring. It is also advisable to check the volume of air flow with a flow meter.

Note: Be aware of static electrification. This is a condition which may occur while running pumps on a lightly loaded or zero loaded cold transformer. Some catastrophic failures have been attributed to static electrification.

OIL FILLED CIRCUIT BREAKER



Function: A circuit breaker is designed to open (trip) during a fault condition, which protects transformers or other sensitive equipment in the circuit. It is also in the circuit to allow the utility or facility to energize or de-energize a transformer or bus section while under load.. The internal mechanism is designed to break and extinguish the arc that is created during the trip operation.

Unique Characteristics: The individual phase tanks are filled with transil oil. This oil insulates the voltage from the grounded tank and extinguishes the arc during the trip operation. Some of the breakers have CTs installed at the base of each bushing. The CTs should be equally warm and will transfer some heat to the main tank. The degree of heating is proportional to the loading of the circuit breaker.

IR Analysis: The circuit breaker is not a heat source under any load condition, the phase tanks should be equal in temperature and ambient. Any temperature rise should be investigated and should be considered serious. The heating of a phase tank usually indicates high resistance of the main contacts that are misaligned or out of adjustment. Normally, some burning and pitting of the main contacts is evident at this point. A dissolved gas analysis of the oil is used to confirm the condition of the contacts.

Oil level indicators should be checked. If the oil level indicator is not visible in the site glass, try to determine the level using IRT. A portable heat source may have to be used to obtain IR level information. If the level cannot be confirmed, the condition should be considered serious.

Most control cabinets have heaters that should be checked for normal operation.

Conclusion: The use of Infrared Thermography as a diagnostic tool has been proven to be one of the top four technologies for the detection of substation anomalies. The other three are sonic / ultrasonic analysis, vibration analysis, and oil analysis. The PDM program uses integration of technologies for decision making. All of these technologies are covered in the Substation PDM Course. If you are interested in attending the Course or if you would like information on the M&D Substation PDM Program, call (800) 745-9981.

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D

AVOIDED COST DEFAULT VALUES

Avoided Cost Default Values

Equipment	Component / Anomaly	Severity	Criteria	Description	GSU Factor	Default Benefit Value *
Transformer, Main Tank	Partial Discharge Detected	Serious	Any Acetylene	Confirmed by DGA	X4	$50,000
Transformer, Main Tank	Internal Vibration / Core Looseness	Intermediate	.25 / .5 ips Harmonic	Confirmed by DGA & Internal Insp.	X4	$10,000
Transformer, Main Tank	Internal Vibration / Core Looseness	Serious	.5 / 1.0 ips Harmonic	Confirmed by DGA & Internal Insp.	X4	$20,000
Transformer, Main Tank	Internal Vibration / Core Looseness	Critical	> 1.0 ips Harmonic	Confirmed by DGA & Internal Insp.	X4	$40,000
Transformer, Bushings	Bushings and connections	Intermediate	10 - 35 C rise	Hot Line of site or internal problem	X4	$5,000
Transformer, Bushings	Bushings and connections	Serious	36 - 75 C rise	Hot Line of site or internal problem	X4	$10,000
Transformer, Bushings	Bushings and connections	Critical	> 75 C rise	Hot Line of site or internal problem	X4	$20,000
Transformer, Control	Control Cabinet Terminal connections, heaters, Etc.	Intermediate	10 - 35 C rise	Hot Line of site Connection	X4	$1,275
Transformer, Control	Control Cabinet Terminal connections, heaters, Etc.	Serious	36 - 75 C rise	Hot Line of site Connection	X4	$2,000
Transformer, Control	Control Cabinet Terminal connections, heaters, Etc.	Critical	> 75 C rise	Hot Line of site Connection	X4	$5,000
Transformer, Cooling System	Loss of Normal Cooling, Pumps, Fans, Controls, Etc.	Intermediate	10/25% Loss	Not working / overheating	X4	$1,000
Transformer, Cooling System	Loss of Normal Cooling, Pumps, Fans, Controls, Etc.	Serious	25/50% Loss	Not working / overheating	X4	$2,000
Transformer, Cooling System	Loss of Normal Cooling, Pumps, Fans, Controls, Etc.	Critical	>50% Loss	Not working / overheating	X4	$3,000
Transformer, LTC	Load Tap Changer	Intermediate	1 - 10 C rise	Overheating with DGA confirmation	X4	$10,000
Transformer, LTC	Load Tap Changer	Serious	11 - 20 C rise	Overheating with DGA confirmation	X4	$25,000
Transformer, LTC	Load Tap Changer	Critical	>20 C rise	Overheating with DGA confirmation	X4	$50,000
Transformer, LTC	Load Tap Changer	Critical		Elevated Arching detected during operation	X4	$50,000
Transformer	Oil level below radiator intakes	Serious		Detected using IR or actual internal insp.	X4	$20,000
Transformer	Galvanized fitting causing Hydrogen Generation	Avoided		Oil Sampling	X4	$2,500
Transformer	Significant Hydran Increase			DGA Confirms Hydran	X4	$2,000
Circuit breaker, Oil	Hot Phase Tank	Intermediate	1 - 10 C rise		X4	$5,000
Circuit breaker, Oil	Hot Phase Tank	Serious	11 - 20 C rise		X4	$10,000
Circuit breaker, Oil	Hot Phase Tank	Critical	>20 C rise		X4	$20,000
Disconnects	Jaw, Hinge, Pad Connections, Etc.	Intermediate	10 - 35 C rise	Hot Line of site Connection	X4	$1,275
Disconnects	Jaw, Hinge, Pad Connections, Etc.	Serious	36 - 75 C rise	Hot Line of site Connection	X4	$2,000
Disconnects	Jaw, Hinge, Pad Connections, Etc.	Critical	> 75 C rise	Hot Line of site Connection	X4	$5,000
Miscellaneous Electrical Equip.		Intermediate	10 -35 C rise	Hot Line of site Connection	X4	$1,275
Miscellaneous Electrical Equip.		Serious	36 - 75 C rise	Hot Line of site Connection	X4	$2,000
Miscellaneous Electrical Equip.		Critical	> 75 C rise	Hot Line of site Connection	X4	$5,000
Miscellaneous Electrical Equip.		Intermediate		Miscellaneous Air Leaks	X4	$200
Oil Filled Electrical Equipment	Low oil Detected	Serious		Visible oil leaks	X4	$1,000
Oil Filled Electrical Equipment	Pegged Low	Critical		Visible oil leaks	X4	$2,000