Gallagher, Carol

Subject: FW: Transmission of NRC Docketed Research Paper - Case Study of Solar Geomagnetic Storm Impacts on Seabrook Station & Financial Returns to Mitigation Investments

Attachments: Seabrook Station GMD Damage & Mitigation Benefits_Filed04262012.pdf

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From: WILLAM HARRIS [mailto:williamrharris@yahoo.com]
Sent: Sunday, April 29, 2012 2:51 PM
To: Wentzel, Michael
Cc: Thomas Popik
Subject: Transmission of NRC Docketed Research Paper - Case Study of Solar Geomagnetic Storm Impacts on Seabrook Station & Financial Returns to Mitigation Investments

FOUNDATION FOR RESILIENT SOCIETIES

April 30, 2012

6/5/2011
76FR47612
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RULES AND DIRECTIVES

Mr. Michael Wentzel
Project Manager
U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation, DLR/RPB2
Mailstop O-11F1
Washington, DC 20555

Dear Mr. Wentzel:

The Foundation for Resilient Societies, a New Hampshire-based nonprofit corporation for which I serve as corporate secretary, submitted to the Nuclear Regulatory Commission a timely-filed set of comments on October 26, 2011 relating to the Draft Final Supplemental Environmental Impact Statement for the relicensing of Seabrook Station Unit 1 for the term April 1, 2030 through March 31, 2050.

Our comments to NRC indicated both a legal duty and practical benefits of including adverse solar weather among the environmental risks to be considered in the Final Supplemental EIS for Seabrook Station. We identified a set of potential mitigation measures that should be subject to SAMA analysis, and possible backfitting requirements to fulfill the Commission's environmental and public safety duties.

We pointed out that mitigating risks of loss of extra high voltage GSU transformers was likely to be cost-effective in reducing the likelihood and duration of station blackout resulting from a severe solar geomagnetic storm. We noted that prolonged station blackout could lead to environmental and public health hazards. We noted that a PRA Type III analysis indicated net benefits from the design and installation of onsite backup power systems to assure reliable water cooling of spent fuel storage facilities, without which severe environmental damage would result. We noted that risks to Seabrook Station appeared to be more severe than risks to the average NRC-licensed nuclear power plant from severe geomagnetic weather, due to proximity to electric-conducting salt marshes, coastal siting, end-of –transmission-line siting, northern latitude, and ground resistance in the region of the plant site.

These comments were based on a modeling effort by Thomas Popik with consultation of various experts, submitted to the Commission in a Request for Rulemaking that preceded and paralleled the accident at Fukushima Dai-ichi, Japan. Our Seabrook Station Comments for a Final Supplemental EIS were *not* based

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Add = M. Wentzel (MJW2)

upon any retrospective analysis of specific instances of solar geomagnetic storm impacts upon coastal New Hampshire or Seabrook Station in particular.

Since that October 2011 filing, our Foundation completed a site-specific retrospective case study of impacts of a moderate level solar geomagnetic upon an extra high voltage transformer at an NRC-licensed nuclear power plant. This was a review of a two-wave geomagnetic storm of November 7-9, 1998 immediately preceding GSU transformer damage and a 12.2 day outage at Seabrook Station.

We submitted this Seabrook Station case study of damage to the generation step-up (GSU) transformer to participants in a Geomagnetic Disturbance (GMD) Task Force of the North American Electric Reliability Corporation (NERC) on January 19, 2012. The Foundation for Resilient Societies filed this brief Research Paper, plus Seabrook Station's own estimate of outage costs and avoided transformer losses through prompt FLIR imaging and shutdown, and a diagnostician review of transformer monitoring technologies; these documents, in a single PDF attachment, were filed with the Federal Energy Regulatory Commission on April 26, 2012, in advance of a Staff Technical Review Conference on Impacts of Geomagnetic Disturbances on Bulk Electric Power Reliability, to be held on Monday, April 30, 2012.

Also on April 26, 2012, at a public information meeting of the Nuclear Regulatory Commission on safety issues affecting Seabrook Station held in Hampton, New Hampshire, I summarized findings of our Foundation Research Paper, and indicated an expectation that hardware protective equipment provides higher financial returns than the practice of "downrating" power generation - with guaranteed revenue losses - during space weather warnings of severe geomagnetic storms. I requested that our Seabrook Station documentation be included in the public record of that meeting, and have subsequently filed the PDF attachment with a Comment on the *regulations.gov* website as Document ID NRC-2011-0299-0001, relating to mitigation of station blackout risks.

Our Foundation has already made a timely-filed request that you, as Project Manager for the Supplemental EIS for Seabrook Station relicensing, include adverse solar geomagnetic weather as a risk to be arrayed against alternative mitigation options for Seabrook Station. We understand from NRC staff disclosures on April 26th that the relicensing decision for Seabrook Station is likely to be extended into year 2014 because of the Applicant's need to document monitoring, testing and mitigation (if required) for alkali-silica reaction (ASR) affecting concrete structures. So there should be ample time to include solar geomagnetic weather risks and mitigation options in your Final Supplemental Environmental Impact Statement for Seabrook Station.

For your convenience, we attach the Foundation for Resilient Societies Research Paper on impacts of a moderate solar geomagnetic storm on Seabrook Station, in advance of the scheduled completion of the Supplemental EIS for relicensing of that NRC-licensed facility.

Sincerely,

William R. Harris
Corporate Secretary
Foundation for Resilient Societies
52 Technology Way
Nashua, NH 03060-3245

From: Wentzel, Michael [mail to: Michael.Wentzel@nrc. gov]
Sent: Friday, September 30, 2011 9:21 AM
To: thomasp@resilientsocieties.org
Subject: Follow-up From the Seabrook Station License Renewal Public Meeting

Mr. Popik,
I am writing to follow-up with the questions that I committed to providing a response to during the Seabrook Station draft supplemental environmental impact statement public meeting.

You had asked if there was any place in the environmental impact statement where initiating event frequency was listed. The environmental impact statement lists the initiating events in Table G-1 of the document, but not their frequencies. Initiating event frequencies can be found in Table F.3.1.1.1-1 of the applicant's environmental report, which I have attached for your reference.
At the meeting you had also asked if the impacts of geomagnetic storms or other solar disturbances have been incorporated in any of the initiating event frequencies. Geomagnetic storms and solar disturbances were not explicitly considered for the Seabrook Station SAMA review. However, it should be noted that loss of offsite power due to weather and grid-related events were considered, and the frequencies were updated in 2004 reflecting the latest NRC and EPRI data on actual loss of offsite power events at nuclear power plants (so loss of offsite power events due to any cause, including solar disturbances if any, were included in the model, just not explicitly by cause).

For your awareness, NRC's response to the letter from Drs. Graham and Pry that you mentioned during the meeting, can be found online at the following links:
http://adamswebsearch2.nrc. gov/IDMWS/ViewDocByAccession. asp?AccessionNumber= ML11228A137
http://adamswebsearch2.nrc. gov/IDMWS/ViewDocByAccession. asp?AccessionNumber= ML112301365

The formal resolution of the comments that you provided during the meeting, and any you may choose to provide prior to the end of the comment period, will be documented in the final supplement environmental impact statement. As a reminder, the comment period on the Seabrook Station draft supplemental environmental impact statement is open until October 26, so if you have additional information that you would like to provide, please do so by that date. If you have any questions on how to provide additional comments, please let me know.

Thanks,
Michael Wentzel
Michael Wentzel
Project Manager
U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation, DLR/RPB2
Mailstop O-11F1
Washington, DC 20555
301-415-6459
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RESEARCH PAPER OF THE

Foundation for Resilient Societies

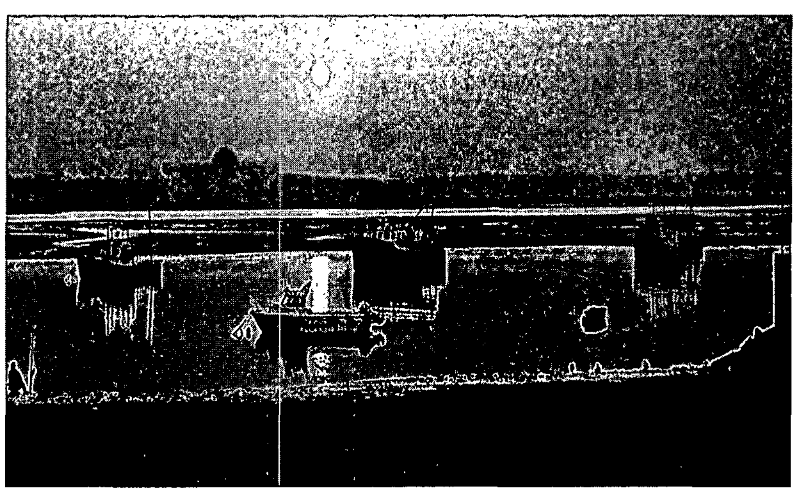
SEABROOK STATION UNIT 1: DAMAGE TO GENERATOR STEP-UP TRANSFORMER IDENTIFIED 10 NOVEMBER 1998 IMMEDIATELY FOLLOWING GEOMAGNETIC STORM SHOCKS OF NOVEMBER 7-9, 1998

William R. Harris
January 19, 2012

Submitted to the Geomagnetic Disturbance Task Force of the North American Electric Reliability Corporation – January 19, 2012;

Submitted to the Nuclear Regulatory Commission in connection with a public meeting on Seabrook Station, April 26, 2012, & NRC review of a Petition for Rulemaking PRM-50-96, Docket NRC-2011-0069, and Proposed Rule-Making to Mitigate Station Blackout, Docket NRC-2011-0299.

Submitted to the Federal Energy Regulatory Commission, as a Comment Related to the FERC Staff Technical Conference on Geomagnetic Disturbances to the Bulk-Power System, FERC Docket AD12-13-000, April 30, 2012.



SEABROOK STATION UNIT 1
DAMAGE TO GENERATOR STEP-UP TRANSFORMER IDENTIFIED 10 NOVEMBER 1998 IMMEDIATELY FOLLOWING GEOMAGNETIC STORM SHOCKS OF NOVEMBER 7-9, 1998

Comments of the Foundation for Resilient Societies, prepared by William R. Harris
January 19, 2012

Highlights

Vulnerability of GSU transformers to moderate-level geomagnetic storms; under-reporting of geomagnetic storm linkages to transformer damage; magnetostriction vibrations as a likely source of stainless steel bolt dislodgment or relocation causing overheating; benefits of continuous transformer monitoring, including GIC monitoring; damage from GICs introduced at high-voltage connections cause damage to windings near low-voltage connections; benefits of infrared monitoring to enable repair instead of total transformer replacement; costs of 12.2 day outage (lost revenue) far exceed costs of hardware protection of GSU transformers from GIC currents; subsequent (year 2000) "downrating" of Seabrook generation during solar storm warnings appears more expensive than hardware protection of GSU transformer; a single Seabrook "downrating" from 100% to 80% of rated capacity for about 40 hours would cost more than neutral ground and capacitor protection; GIC hardware protection can enable "operate through" as a "best practice" for moderate geomagnetic storms; a new GSU transformer that is designed with hardware to protect against GIC damage to a <u>future-installed</u> GSU transformer could be designed also <u>to protect the existing GSU transformer</u> at Seabrook Station.

<u>BACKGROUND</u>

Seabrook Station Unit 1 is located adjacent to the Atlantic Ocean on the New Hampshire seacoast. Its pilings are proximate to electric-conducting salt marshes, and end of transmission lines that amplify geomagnetic induced currents. The geospatial siting and salt water conditions are similar to those adjoining the Artificial Island that links the saline waters on the perimeter of Delaware Bay to nuclear generating units at Salem 1, Salem 2, and Hope Creek in southern New Jersey.[1]

Seabrook Station Unit 1 utilizes a generator step-up transformer designed by General Electric and manufactured in year 1981. Five 345 kV / 25 kV transformers are on site at Seabrook Station: the GSU transformer connected to turbines of the Westinghouse pressurized water reactor; three transformers connected to gas insulated switches for each of three EHV transmission lines; and an auxiliary backup transformer.

The on-site GSU transformer was installed at Seabrook in approximately 1982, and provided power during site construction before the NRC grant of an initial operating license in March 1990. The GSU transformer operated at full generating capacity, except for periods of maintenance since Seabrook

[1] NERC maintains an online-available data file on the March 13-14, 1989 solar geomagnetic stock and blackout that identifies damage to the Salem Unit 1 GSU transformer. As with the Seabrook GSU transformer, the GIC currents appear to have entered through the high-voltage connection and caused extensive damage near the low-voltage connection and transformer windings. See also Metatech Report R-319 for images of Salem 1 transformer damage in March 1989.

received its full power operating license in August 1990. The Seabrook Station GSU transformer operated without incident during more than eight years of full power generation between August 1990 and November 1998. Seabrook Station, when operated by Public Service Co. of New Hampshire,[2] did not utilize magnetometers to measure or record near-station geomagnetic induced currents.

A SOLAR GEOMAGNETIC STORM, WITH MORE THAN FIVE HOURS OF CORONAL EJECTA ON NOVEMBER 5, 1998 RESULTED IN A MODERATE LEVEL GEOMAGNETIC STORM ON EARTH ON NOV. 8 AND A PARTIALLY OVERTAKING GEOMAGNETIC SHOCK AT THE EARTH'S SURFACE ON NOVEMBER 9, 1998.[3]

Without direct on-site geomagnetic induced current (GIC) monitoring, we only estimate the effects of this two shock geomagnetic storm in the Seabrook region as roughly twice the equatorial network estimate of – 149 nanoTeslas on November 8 and – 142 nanoTeslas on November 9, 1998. Storm magnitude measured at the Fredericksburg, Virginia station peaked at A-36 and K-6 on November 8, and A-30 and K-5 on November 9th. At the higher latitude College Station, the Nov. 8th peak was A-58, K-7. With the partial overtaking of a second shock wave, the Nov. 9 index peaked at A-130, K-9.

SEABROOK PHASE A GSU TRANSFORMER OVERHEATING, AND GENERATION SHUTDOWN ON NOVEMBER 10, 1998.

On November 10, 1998, Seabrook Station engineer Richard Bjornson participated in a thermal IR imaging of the GSU Transformer at Seabrook Station. His report, which credits FLIR imaging as enabling prompt shutdown and repair of the GSU transformer, does not explain the symptoms exhibited by the GSU transformer which led to the FLIR imaging and prompt generation shut down.[4] Prompt imaging and inspection of the GSU transformer identified melting of aluminum and copper, and windings at the low-voltage end of the transformer.

The root cause of the accident was reported as, and appears to have been, a dislodged stainless steel bolt located near the low voltage windings.[5]

However, the *proximate cause* of the severe damage to the Phase A of the three phase GSU transformer appears to have been GIC currents, which are known to have caused at least two shocks over short duration, in Canada, the United States, India, China and perhaps other observatory locations. Seabrook is most prone to eastward electrojets that can be amplified over more than thirty miles of the 345 kV

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[2] In the year 2002 a subsidiary of Florida Power & Light acquired a financial interest of somewhat more than 88 percent in the Seabrook Station facilities.

[3] Research articles addressing the GIC shocks of Nov. 8th and partially overtaking ("cannibalizing") shock of November 9, 1998 include L. F. Burlaga, R. M. Skoug, C. W. Smith, D. F. Webb, T. H. Zurbuchen, and Alysha Reinard, "Fast ejecta during the ascending phase of solar cycle 23 – ACE observations in 1998-1999," J. Geophysical Research, 106:20,957-20,777 (2001); Yuming Wang, C. L. Shen, S. Wang, and P.Z. Ye., "An empirical formula relating the geomagnetic storm's intensity to the interplanetary parameters *VBz* and *t*," Geophys. Res. Lett. 30 (2003); and J. Zhang, K. P. Dere, R. A. Howard, and V. Bothner, "Identification of solar sources of major geomagnetic storms between 1996 and 2000," Astrophysical J. 582: 520-533 (2003).

[4] See the report by Richard Bjornson, "Generator step-up transformer, low voltage bushing overheating event." This report is attached as a .PDF document to this commentary. It contains FLIR images and photography of the damaged Phase A of the GSU transformer.

[5] This was Bjornson's initial finding. It is further documented in Seabrook Station notes, reviewed with this commentator by NextEra Energy in January 2012. We wish to express appreciation to officials of NextEra Energy for their cooperation in facilitating understanding of these events.

Scobie transmission line, an east-west oriented line. But this geomagnetic storm had a *northward* thrust, and is likely to have been amplified by the transmission lines that serve the Boston metropolitan area to the south of Seabrook Station. Absent on site GIC monitoring, we do not know for sure which transmission line was most associated with the GIC surges that damaged one of three phases of the Seabrook GSU transformer.

An extensive literature on *magnetostriction* explains how GICs cause vibration in GSU transformers. These vibrations increase at least five fold during high GIC events. These vibrations are associated with harmonic effects within the transformer core. It is foreseeable that GIC shocks that occurred on November 8, or 9, 1998 could have dislodged a vibrating stainless steel bolt. Alternatively, a previously dislodged stainless steel bolt, inside the GSU transformer, vibrated into a position where it caused severe overheating. GICs within the transformers can reach several hundred or thousands of degrees, with the energy flowing from the high voltage towards the low voltage windings and bushing.

Neither the Seabrook Station employee-observer, Mr. Bjornson, nor an outside contractor-diagnostician, Jon L. Giesecke, identified the immediately preceding geomagnetic storm as the proximate cause of the GSU transformer damage identified on November 10, 1998. They were not aware of the geomagnetic storm at all.[6]

The Bjornson study estimates that the costs of total transformer loss, generation outage, and replacement would have incurred costs of about $74 million in 1998 dollars. Seabrook lost generation and associated (potential) penalties were estimated at $43.3 million. Replacement power costs were estimated at about $7.2 million. Parts and labor were estimated at $21.7 million. Total loss and delayed restart of Seabrook was estimated as a $74 million dollar loss, more or less. The actual loss for a 12.2 day outage of electric generation, and repair of the Phase A of the GSU transformer, was only $12.2 million, including $7.3 million in forfeited generation revenues, $1.2 million in costs of replacement power, and $3.7 million for transformer parts and repairs.

LOOKING AHEAD: WHICH PROVIDES A BETTER RETURN ON INVESTMENT: LEAVING GSU TRANSFORMERS WITHOUT NEUTRAL GROUND AND CAPACITOR-RESISTANCE PROTECTION, OR PURCHASING GSU HARDWARE PROTECTION?

If a generation facility operates without hardware protections for extra high voltage GSU transformers, the existing "best practice" in the industry is to downrate from peak rated power output to a lesser level of electric generation during space-weather warning periods above a certain magnitude. What are the costs of this "operate through" strategy?

First, there is the cost of reduced generation and reduce wholesale electric revenues to the plant owner. The cost per day for Seabrook Station, at about 1260 MW of capacity, was about $600,000 per day in 1998, or about $850,000 per day in year $2012 inflation adjusted dollars. For firm sales not delivered, there could also be costs of replacement power.

Secondly, there may be additional costs associated with reduced transformer life. The Bartley data from the years 1997 through 2001 demonstrates that GSU transformer loss claims in a high GMD year (2000)

[6] The Report by Jon L. Giesecke, "Condition Assessment (L2CA) of Transformers / Substations," 2003, is attached as a PDF file. It utilizes the Bjornson FLIR imaging. Neither Mr. Bjornson nor Mr. Giesecke was aware of the two day geomagnetic storm immediately preceding the Seabrook transformer failure when they prepared their reports. Telecom courtesy of Mr Giesecke, January 2012.

were six times the GSU transformer loss claims for the average of four surrounding years with lower GDM insults. [7] "excess" loss claims for GSU transformers for year 2000, a high GMD year, were approximately $136 million in inflation adjusted year $2011 dollars. This does not even count the indirect costs of late transformer failures – in later years, but accelerated because of prior year GMD insults.

Further, if hardware protection of GSU transformers reduces the throughput of geomagnetic induced (DC) currents that may flow from transformers into transmission systems, there may be other cost-savings through the protection of GSU transformers for extra high voltage systems throughout North America. Will there be reduced VAR consumption? Will there be a reduction in "congestion" losses during years with high geomagnetic storm frequency and intensity? We are likely to learn the answers if there are sufficient "early adopters". If the transmission system achieves reduced power losses, or reduced VAR losses, or reduced "congestion" losses, or reduced unscheduled bulk power deliveries to areas not under contract, the results are likely to show up on the annual aggregation of FERC Form 1s. These are the annual reports on net operating income for all major electric utilities subject to FERC jurisdiction.

For Seabrook Station, a single instance of "downrating" by 20 percent during a geomagnetic storm – such as occurred in the year 2000 – can cost as much as hardware protections, including GIC monitoring, in just 40 hours or less of cumulative "downrating" time. This estimated breakeven point does not even include risks of total transformer loss, reduced transformer life, replacement costs for undelivered power, or VAR consumption losses.

What is required to "operate through" a moderate level geomagnetic storm – such as Seabrook experienced in November 1998 – without losing electric revenues? It takes some modest changes in "current practices_ -- *sometimes claimed to constitute "best practices."*

To "operate through" a modest level geomagnetic storm it would be prudent to monitor functionality of EHV transformers. If performance appears to be degraded, "downrating" can be instituted fairly rapidly. Some of the performance indicators may include: partial discharge monitoring, GIC current monitoring, temperature monitors at multiple points, or FLIR imaging at multiple points, and acoustical monitoring at multiple points. With an appropriate near-real-time monitoring program in place, it should become prudent to "operate through" at least moderate level geomagnetic storms. Some analysts have confidence that the current designs for protective hardware will enable "operate through" as a best practice at even higher levels of geomagnetic storms.[8] Early adopters within the electric utility industry will set the pace, and hopefully reap the financial returns that accrue to more innovative system managers.

With careful planning, it should be feasible to install hardware protections for existing GSU transformers, while designing compatible connections for this equipment when replacement GSU transformers are installed in out-years. Time will tell.

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[7] See William H. Bartley, "Analysis of Transformer Failures," Hartford Steam Boiler Inspection & Insurance Company, IMIA-WGP Report 33 (03), Stockholm, 2003, available on the internet.

[8] Personal communication from John Kappenman, January 2012.

Generator step-up transformer, low voltage bushing overheating event

Richard Bjornson

Seabrook Nuclear Power Station, Seabrook, NH

ABSTRACT

On Tuesday, November 10, 1998, personnel from the Component Engineering Department and CSI Services conducted a self-assessment of Seabrook Station's Infrared Thermography Program. While performing the self-assessment, a high temperature on the Generator Step-Up Transformer (GSU) was discovered. One of six low voltage bushing enclosures was found to be much hotter than the other five. Peak housing temperatures were approximately 250° F as compared to 110° F for like enclosures. An infrared inspection through a 3/8 inch bolt hole identified temperatures in excess of 540°F. The plant immediately commenced shutdown. Subsequent inspection of the transformer/bus connection revealed significant overheating damage to the 25 kV connection. Melted aluminum, copper and even a 304 SS bolt was discovered.

Root cause analysis concluded that a complete connection failure would have occurred within 2 weeks.

This paper describes the event and demonstrates how the cost benefit analysis for this Infrared discovery, using the EPRI cost-avoidance model and industry experience, is estimated to have saved over $32 million.

Keywords: IR thermography, electrical survey, transformer

1. INTRODUCTION - INFRARED THERMOGRAPHY (IRT) CASE HISTORY

North Atlantic Energy Service was performing a routine thermographic inspection as part of the self-assessment program at Seabrook Nuclear Station, a 1200 megawatt nuclear power generating facility in New Hampshire. What appeared to be a serious temperature rise was detected on a 25kV to 345kV Generator Step-up "A Phase" Transformer. The location was on an Isophase-to-Low-Side bushing where an apparent temperature rise of 150°F was detected on the surface of the bushing compartment.

Fig.1 is a visual image of the "A" Phase Generator Step-Up Transformer, Low Side Bushing Compartment. Fig.2 is the corresponding thermal image. The 250°F temperature measured on the surface of the bushing compartment exists because of heat being generated inside the compartment. The source of the heat was suspected to be a high resistance connection between the low side bushing and the isophase. Recognizing that a significant heat source would be needed to raise the surface temperature of the compartment to 250°F, it was suspected that there was potential for a catastrophic transformer failure.

Figure 1 Visual image of the "A" phase generator step-up transformer

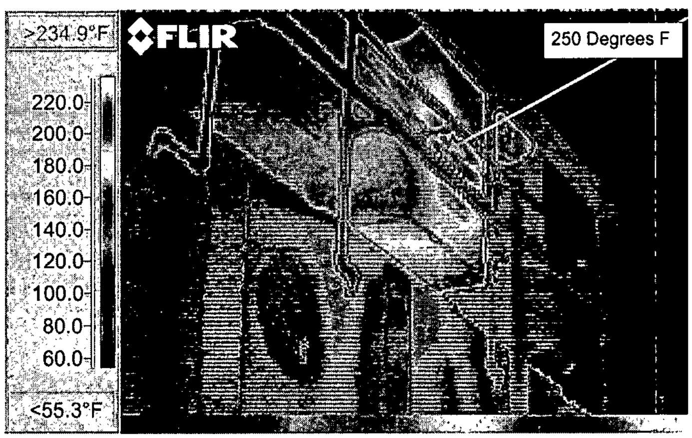

Figure 2 Corresponding thermal image of the transformer

2. CONCERNS:

The finding prompted immediate concerns as follows:

Safety - A catastrophic failure of the transformer could have devastating safety consequences for plant personnel.

Environmental - It is assumed that fire resulting from a transformer explosion could be controlled, however, an adjacent salt marsh could be contaminated.

Lost Power Generation - Loss of the "A" Phase Generator Step-Up Transformer requires a forced plant shutdown.

Component Damage - Component damage is expected.

3. INITIAL RECOMMENDATIONS

Initial recommendations based on the above concerns were:

Remove the unit from service.
Inspect the low side transformer bushing and all other associated components.
Make repairs as necessary.

4. RESULT OF INITIAL RECOMMENDATIONS:

An inspection of the inside of the bushing compartment revealed significant damage, including substantial melting and deterioration of the bushing and surrounding components. These components had been exposed to extremely high temperatures. The melting temperature of aluminum is approximately 1220°F. Fig.3 illustrates some of the damage sustained by the transformer bushing links.

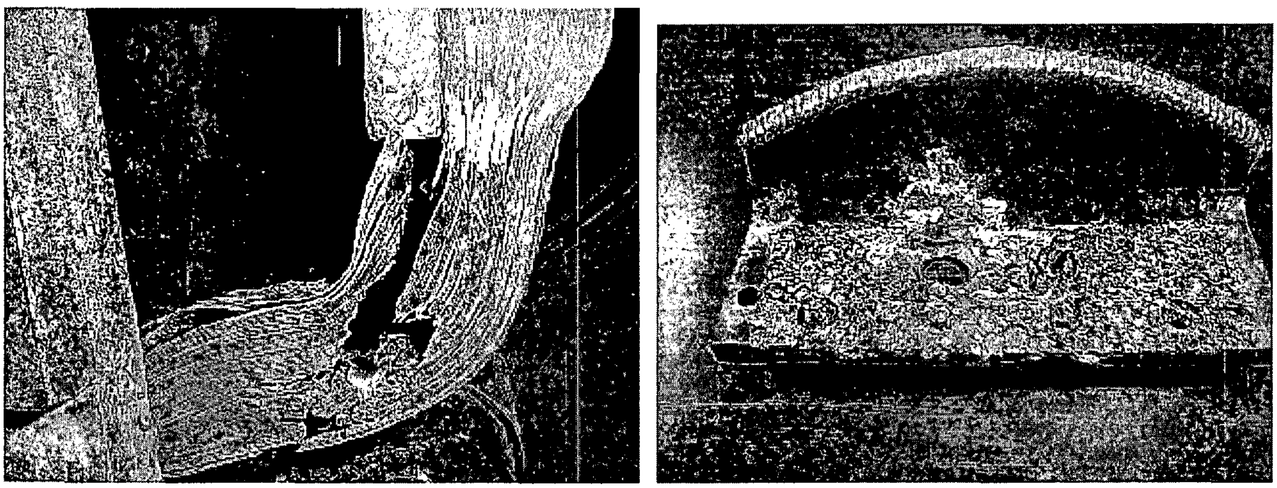

Figure 3. Photographic illustration of some of the damage sustained by the transformer bushing links

5. CONCLUSION

A non-intrusive diagnostic test, using infrared thermography, exposed a situation where an incident would have certainly occurred. By detecting this situation, an opportunity was created for operations and maintenance personnel to take appropriate action. The station was able to avoid a catastrophic failure, and the associated issues and costs.

6. COST AVOIDANCE BENEFIT ANALYSIS:

If a Predictive Maintenance (PdM) program is working, and equipment failures are detected in their incipient stages, maintenance can be performed to correct problems before the equipment fails. This is the premise upon which PdM philosophy is based. Unfortunately, this situation makes the computation of cost benefit (dollar savings) attributable to a particular PdM finding somewhat difficult to quantify. The event that would have taken place, had diagnostic testing not been available, is uncertain. Proposed scenarios of what could have taken place, based upon knowledge of equipment functionality and its maintenance history, must be relied upon.

By proposing three, or fewer, general failure scenarios, and applying a probability of occurrence to each of them, cost benefit can be reasonably estimated. These scenarios could be classified as "Most Severe", "Medium Severity" and "Least Severe". The cost avoidance benefit for this case is calculated by estimating the cost for each scenario, subtracting the actual cost from each of the estimated costs, weighting each net cost by the likelihood of its occurrence and adding the results as follows:

• Scenario #1 Most Severe Event - There is no PdM program. The situation goes undetected. An explosion destroys the transformer and bus ducts. Damage is sustained by the turbine building. Burning oil contaminates the adjacent salt marsh. Industry averages for these catastrophic failures indicate that there would be 72.2 days of plant shutdown. Root cause analysis of this event concluded that there is a 50% chance that this catastrophic scenario would have taken place.

• Scenario #2 Medium Severity Event - There is no PdM program. The situation goes undetected. The resultant fault causes protective relays to trip the plant. The "A" Phase low voltage bushing, duct links and bus duct are destroyed. There is no further transformer damage. The plant would be forced to shut down for approximately 15.2 days. Root cause analysis of this event concluded that there is a 50% chance that this medium severity scenario would have taken place.

• Actual Event - In actuality, the situation was detected by a PdM diagnostic program and repairs were made. The unit was put back into service after an outage of 12.2 days.

Costs attributable to:

Scenario #1	
Lost Generating Revenue & Associated Penalties	$43,320,073
Replacement Power Costs	7,220,000
Parts & Labor	21,660,010
Replacement Transformer	1,900,000
Total Costs Scenario #1	**$74,100,083**
Scenario #2	
Lost Generating Revenue & Associated Penalties	$9,123,831
Replacement Power Costs	1,520,000
Parts & Labor	4,559,985
Total Costs Scenario #2	**$15,200,125**
Actual Event	
Lost Generating Revenue	$7,320,028
Replacement Power Costs	1,200,000
Parts & Labor	3,660,005
Total Costs Actual	**$12,180,034**

	Scenario #1	Scenario #2
Proposed Costs	$74,100,083	$15,200,125
Less Actual Costs	(12,180,034)	(12,180,034)
	$61,920,049	$ 3,020,091
X % probability of event	X 50%	X 50%
Sub-Totals	$30,960,025	$1,510,046
COST AVOIDANCE BENEFIT	$30,960,025+$1,510,046	**$32,470,071**

JLG Associates

Level II Condition Assessment (L_2CA) of Transformers / Substations

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Providing Services, Training & Products to the Electric Power Industry

The Aging of America's Transformers

The aging of the electrical infrastructure in the United States is a critical problem that until recently has gone unnoticed. As these aging transformers begin failing, a new level of awareness of the magnitude becomes very clear. Many transformers fail each year across the USA unnecessarily. Proper care and condition assessment of these valuable assets is needed now more than ever. With the transformer average age approaching 40 years and the new transformer fleet with a higher than normal failure rate, a pro-active approach is needed.

Large power transformers are not easily obtained and must be ordered one to two years in advance. The larger units are not being manufactured in the USA. The repair and replacement schedule is critical in most cases. Knowledge of their condition is of utmost importance; that is where JLG Associates comes into play.

Since the establishment of the interconnection grid, the electrical system of each member of the grid became a piece of the electrical infrastructure of America. This infrastructure is vital, and as we witnessed several years ago, a relatively small problem resulted in the largest blackout in our history. This blackout clearly demonstrated the fragility of our system.

The crucial nature, fragility, age and long lead time for major components, and interconnection of our nation's electrical system demands the best maintenance approaches possible to help ensure reliability. Ironically, at the time of the blackout, the author, Mr. Jon Giesecke, was traveling home after doing a condition assessment of a nuclear generating station's main power transformers. A major thrust in Jon's work is finding and utilizing the optimum test methods and test equipment for the condition assessment of oil filled power transformers and their various sub-systems. His association with the Electric Power Research Institute (EPRI) over the years has allowed him to search out and test many systems and methods for this purpose.

This paper will clear up many questions and become a resource to those seeking to better determine the condition of the large oil filled transformers under their care.

The testing described in this paper is done on energized, fully loaded transformers. No clearance or blocking is needed to accomplish these tasks. In fact, often the higher the load, the better the testing capability. All tests are completely non-intrusive.

Level 1 Verses Level 2 Transformer Inspections

About 97% of utilities in the U.S. do a Level 1 inspection to some extent. Level 1 consists of: Visual, Infrared Thermography and Oil analysis. A complete level 2 condition assessment (L_2CA) of oil filled power transformers includes the following:

- Visual Inspection
- Partial Discharge Detection
- Arc Signature Analysis
- Lightning Arrestor Testing
- Infrared Thermography
- Vibration Analysis (main tank and pumps)
- Functional Testing of Cooling System & Load Tap Changer (LTC)
- Dissolved Gas Analysis (DGA) & Oil Quality Review
- Furan Analysis Review
- Review of Transformer Loading History

Unexpected Failures are Unacceptable

Very rarely will a failure occur without first revealing some small change that is detectable using one or more technology implemented in a Level 2 Condition Assessment. Combining data from the various technologies allows us to understand pre-failure signs of the transformer and the health of the transformer's sub-systems, which include the pumps/cooling system, load tap changer (LTC), no load tap changer (NLTC) and lightning/surge arrestors.

To be able to trend a condition means that you have something to compare. Below is an eight point recipe for success; this is where it all starts and it involves all the listed technologies from the L2CA list above.

- You must have the attitude that predictive maintenance (PdM) is king.
- Assign people for this task
- Acquire tools for this task
- Create and commit to a system to collect baseline data.
- Collect baseline data.
- Follow-up with subsequent surveys to create a trend.
- Create meaningful condition assessment reports.
- Take appropriate actions based on report findings.

During the baseline data collection, many problems and anomalies will surface and have an effect on the way maintenance is approached at your facility. Major failures will be averted. Major money will be saved. A major safety feature will be built in to every visit to the high voltage transformer yard.

Detecting Acoustic and Electrical Problems on Energized Equipment

Acoustics have been used for many years to detect and locate partial discharges in power transformers. Only recently has the addition of a high frequency current transducer (HFCT) installed on the case ground of the subject transformer made the process complete. To distinguish mechanical from electrical problems in oil filled transformers using only acoustics is more difficult.

Partial Discharge Detection on Energized Equipment

Partial discharge testing using acoustic sensors and a high frequency current transducer makes the determination easy and also increases the protection factor for these utility industry assets. Figure 1 shows acoustic activity and electrical activity obtained simultaneously. The top portion of the screen shows the acoustic and the bottom shows the electrical data from the current transformer (CT). The cursor positions shown by the arrows, allow the user to determine the time difference of each burst. The circled numbers show a 16 ms (millisecond) difference is present in both acoustic emission (AE) and electrical. This indicates the activity takes place at the voltage peak of each cycle.

This is classic partial discharge (PD) in a power transformer. Partial Discharge is unwanted electrical activity which is present is approximately 80% of oil filled power transformers. Low level PD activity may continue for the entire life of the transformer. It is when this insulation breakdown gets to a point that threatens the life of the transformer that we are interested in. PD is similar to corona activity and occurs at the high voltage peaks. Most low level PD activity is load dependent. As the load increases the voltage decreases. When the voltage decreases the PD will decrease or disappear completely then return when the voltage returns to full value.

Since PD is present in so many transformers, it is critical to know the present condition and be able to make a decision on when to take action. There are 2 pieces of test equipment used for baseline and trending. The first test is taking a snapshot of data to determine any unwanted activity; the second is trending the PD activity by gathering continuous data over a month's time to determine whether further action is needed.

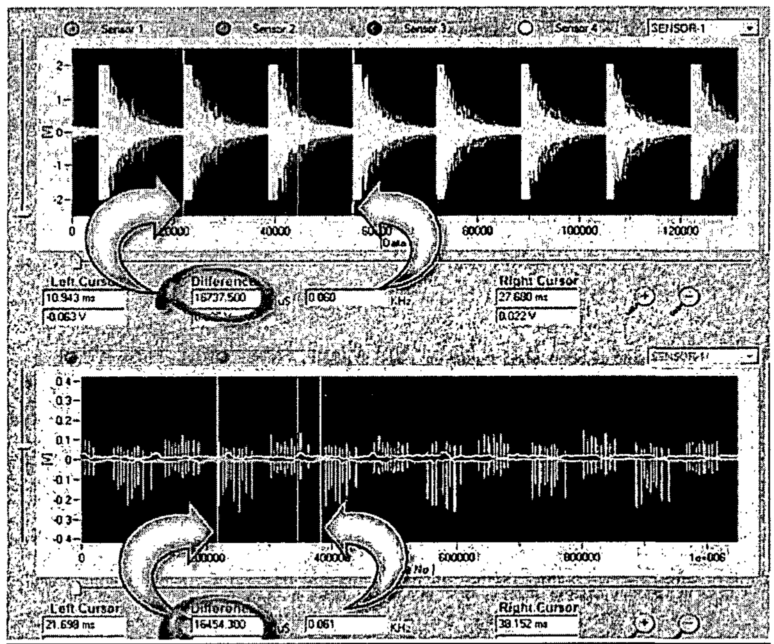


Figure 1: Transformer acoustic (top) and electrical activity on the same time line.

Locating the source of PD or arcing is made easy using 4 acoustic sensors and a software process that uses time of arrival of the AE signal. The software triangulates and puts a spot (pink ball) in a virtual 3D transformer on the computer screen. Figure 2 gives an example of this where the larger balls indicate sensor location on the surface and the smaller, interior ball indicates the source of the PD. Each AE sensor is color coded, measurements of the transformer size and location of the sensors are entered into the software to produce the below 3D graphic. This is a top down view; the graphic can be rotated in any desired position during this process for ease of source location.

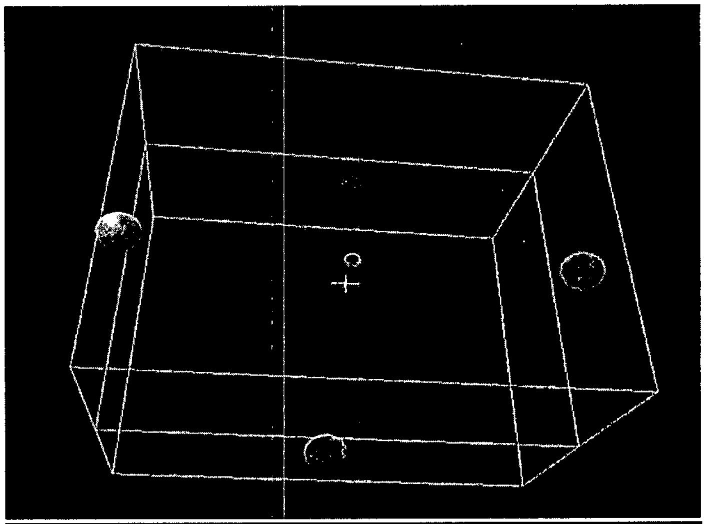


Figure 2: Top view of transformer indicating location of sensors, (large balls), and source, (small interior ball) This is only possible when 3 or more sensors detect the source. An X-Y source location method is used when only 1 or 2 sensors detect the fault.

Trending Partial Discharge and Arcing

Trending the deterioration process aids the asset manager in the deciding when to take action. Asset managers need to know what to do and when to do it to be able to avoid the up-coming failure. The acoustic and electrical are measured for amplitude and duration as shown in Figure 3. This is easily trended by comparing subsequent test results under similar conditions. The top screen shows the AE bursts with sensor #3 (blue) being closet to the source. The bottom screen shows the electrical burst captured from the case ground lead using the HFCT.

The burst captured by the HFCT (bottom screen of figure 3) was obtained by expanding one spike shown in the bottom screen for figure 1. This is the classic shape of PD activity.

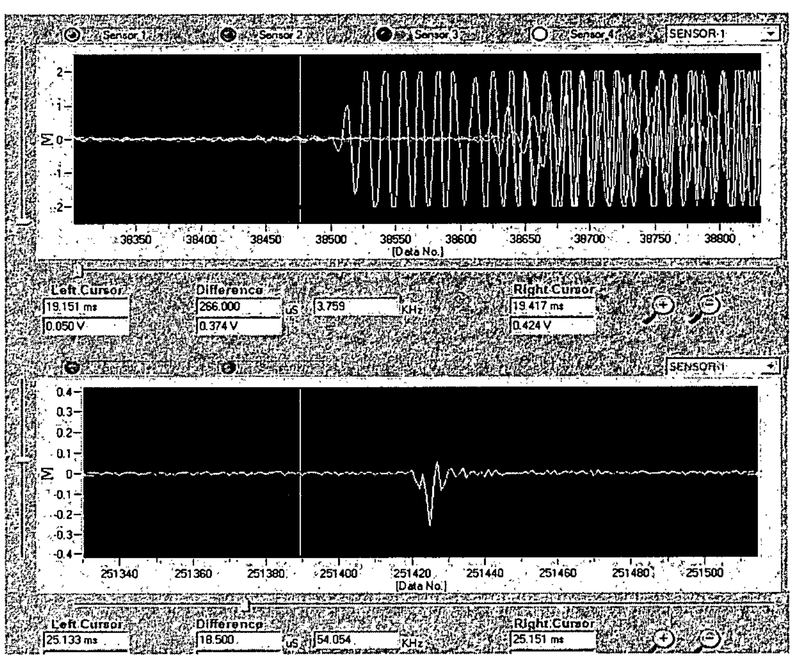


Figure 3:

Load Tap Changer Analysis

Figure 4 shows acoustic and electric signatures of a vacuum type LTC. The trace on the bottom screen indicates a problem with B phase of this transformer. The timing is off (not equidistant between contact operation) and also the activity just before and after the center burst indicates some electrical activity associated with poor contact quality.

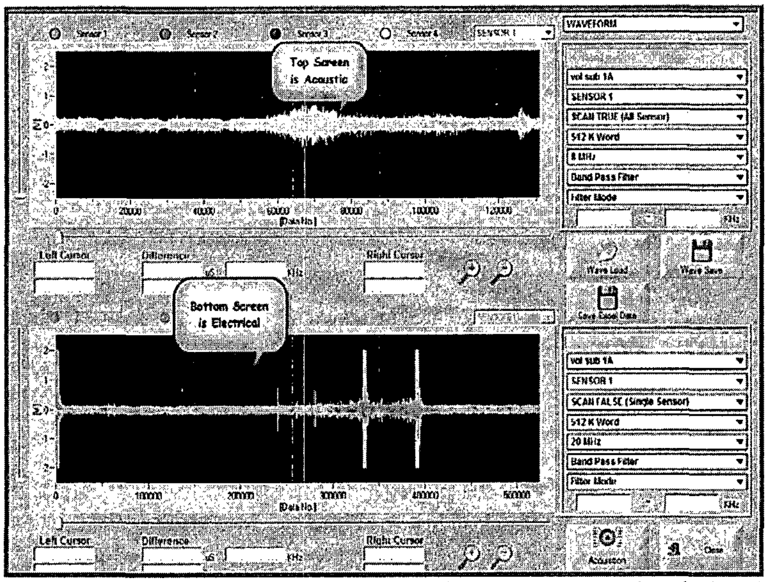
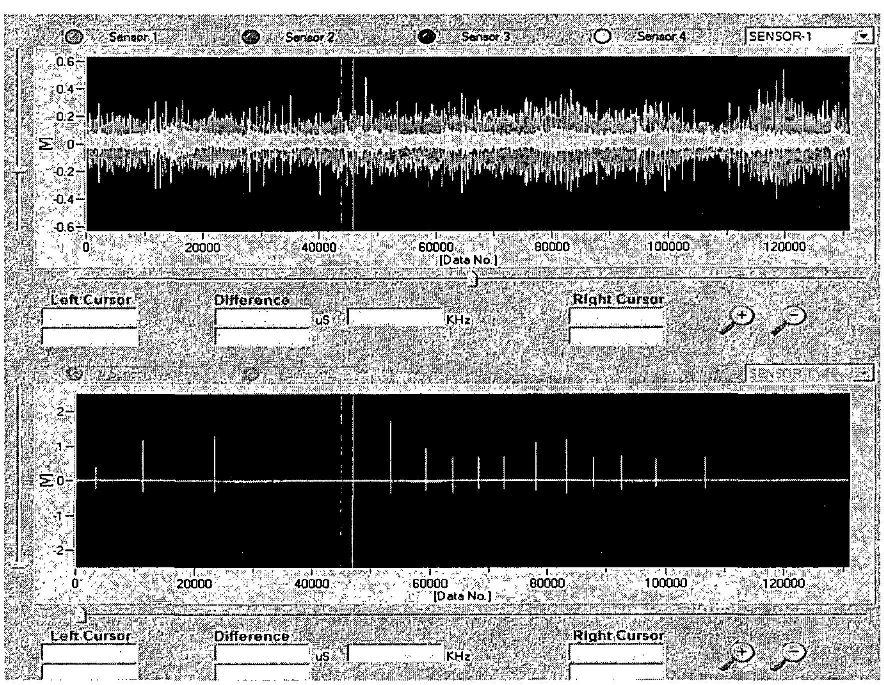


Figure 4: Acoustic and electric signatures show 3 contacts arcing during the operation of a vacuum type LTC.

Lightning Arrestor Testing

Figure 5 indicates a problem with this 500 kV lightning arrestor. The middle screen is showing activity from the arrestor and there should be none. The HFCT is on the arrestor ground lead above the strike counter. The acoustic activity on the top screen is from normal transformer noise. The bottom screen is a time expanded view of an electrical spike on the middle screen, showing the typical pattern of a problematic lightning arrestor.



Cooling System Pump and Motor Analysis

Figure 6 indicates a normal pump/motor. Figure 7 is from a pump/motor combination that has a rubbing problem in the impeller, which may circulate small metal particles into the transformer. No anomalies appear in the electric signal, but the acoustic signal has periodic noise on it.

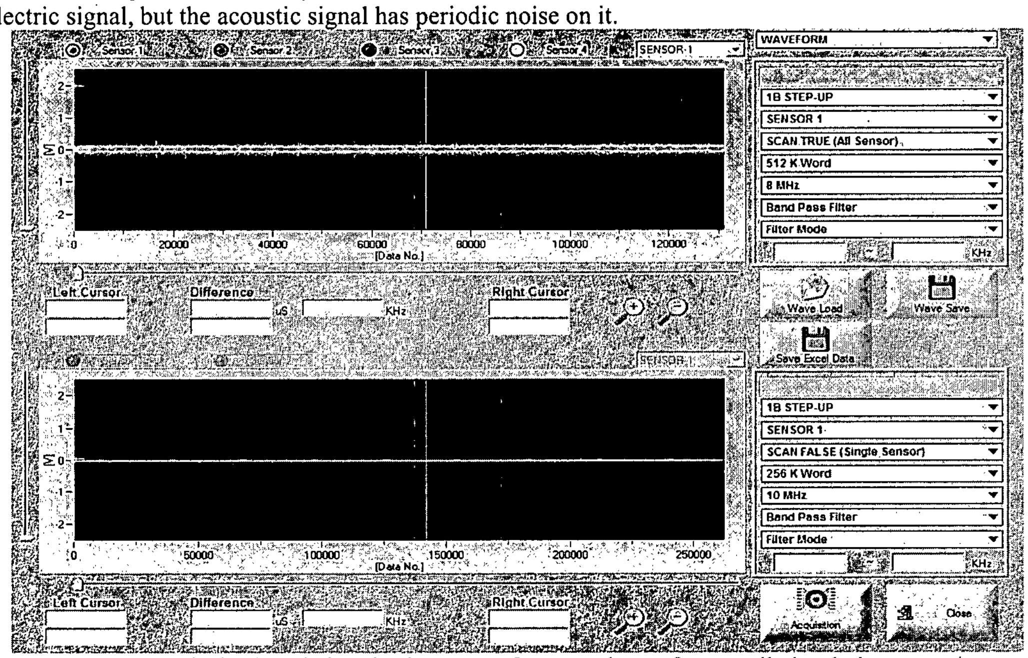


Figure 6: Acoustic (top) and electric signature of a normal transformer oil circulating pump/motor combination.

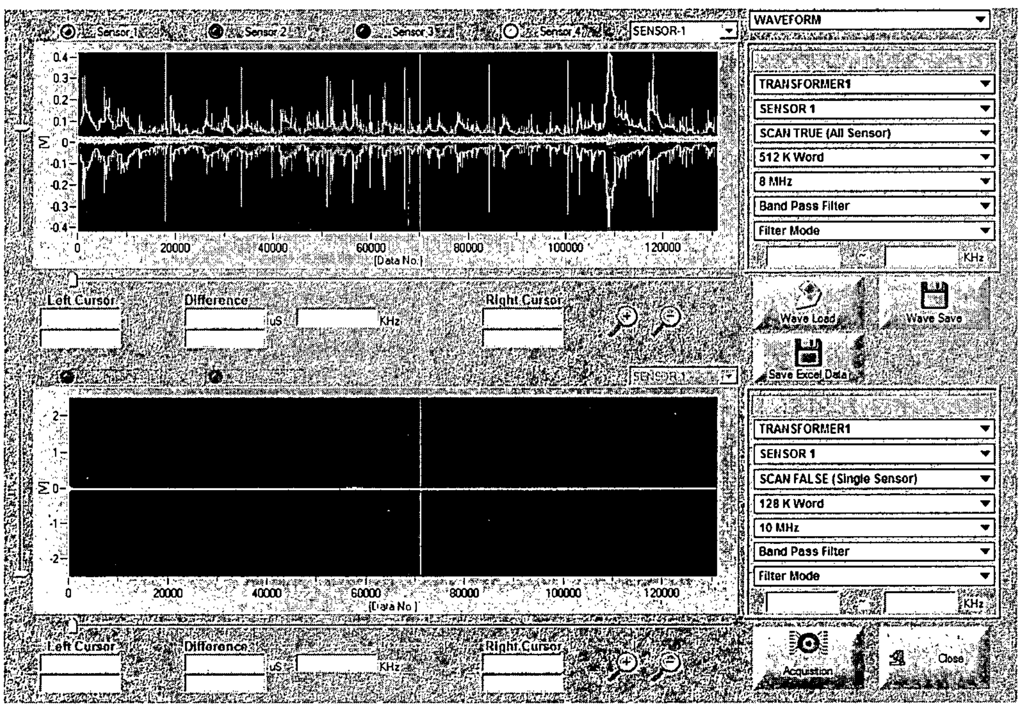


Figure 7: Acoustic (top) and electric signature of a problematic transformer oil circulating pump/motor combination.

Arcing detected inside the transformer main tank.

Figure 8 indicates arcing inside the main tank of an oil filled power transformer.
A slight indication of PD is present in the top screen, sensor #2 (red). The cursor measures one full sign wave.

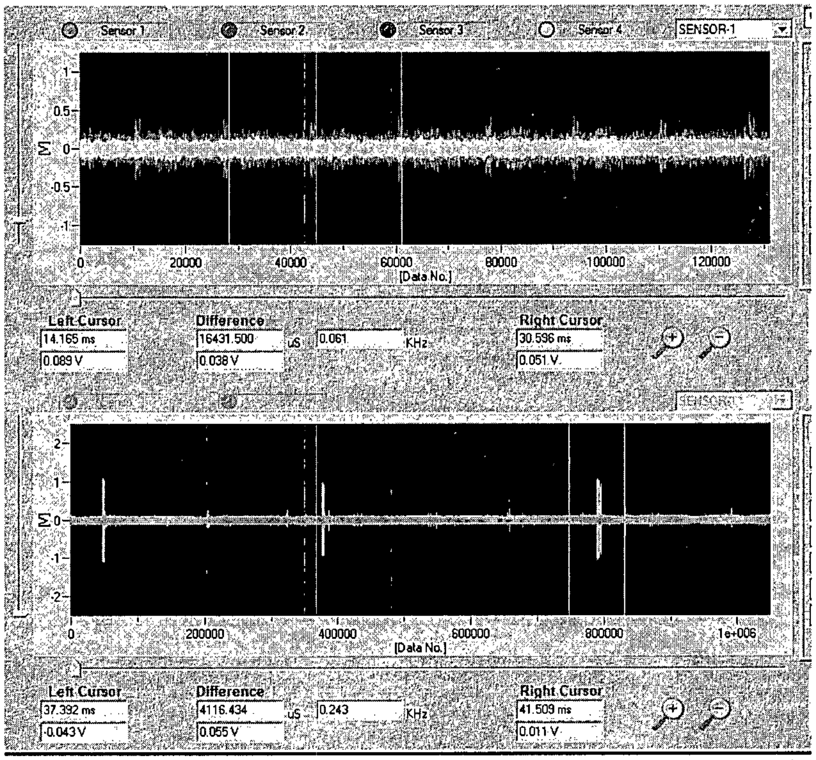


Figure 8: Acoustic (top) and electric signatures of a transformer with internal arcing in the main tank.

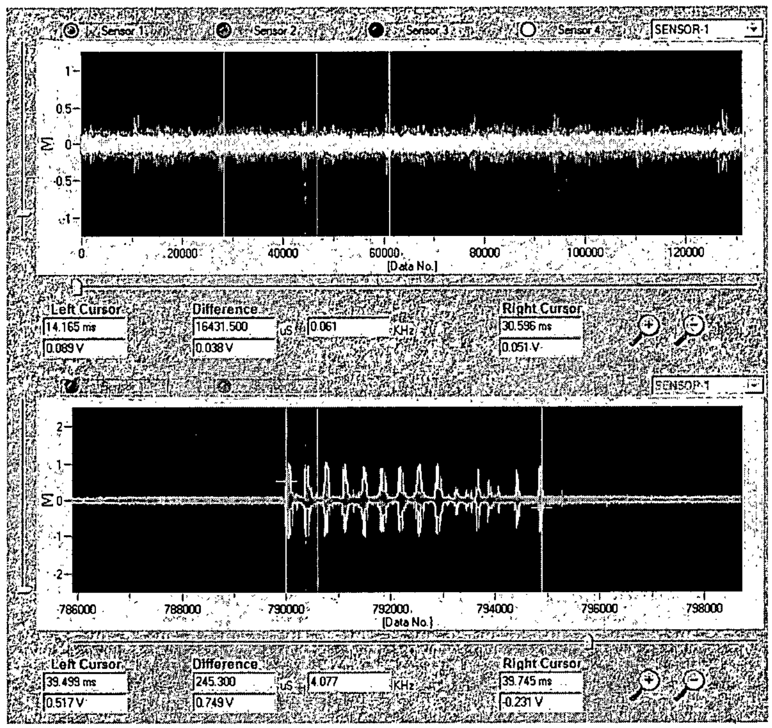


Figure 9: Time-zoomed view of a spike shown in figure 8 showing it is really a series of short bursts lasting 245 uS; this is an arc.

Figure 9 shows the expanded burst from fig. 8. The duration of this arc is 245 micro-seconds. Notice that the single burst in fig. 8 is really a series of bursts.

This transformer's DGA data indicated 65 ppm of acetylene; this is a doubling of the acetylene in 2 months. Although the DGA data indicated arcing, the visual proof and the ability to source locate the point of the arc is of great value.

Infrared Thermography

Infrared Thermography is another key tool in the transformer L_2CA process. A level 1 IR (L1-IR) inspection is normal in most utilities. This paper will attempt to show the need to advance your program to L_2CA.

A level 1 IR inspection gives very limited information about the transformer itself. Level 1 IR for the most part, looks at the primary connections to the exposed bushings, the LTC differential, the temperature rise on the lightning arrestors.

The complete L_2CA includes all L1-IR inspections plus:

- A bushing inspection including the UST, porcelain and oil expansion chamber
- A cooling system functional check, running all fans and pumps, checking pump/motor heating/fan heating, checking radiator inlet to outlet differential temperatures, complete control cabinet scan, mini-calibration of temperature gauges, oil level confirmation.
- A scan of the isolated phase bus and low voltage ducts
- An LTC profile & differential measurement
- A main tank inspection for odd heating patterns/hot spots

The main tank of the transformer including the core and coil assembly and the de-energized tap changer (DETC) is the heart of the transformer. Infrared thermography has limited value when determining the condition of the main tank, however doing a scan of the main tank may reveal a hot spot which could be an issue that will be confirmed by a combination of ultrasonic analysis, vibration analysis and oil analysis. It is the combined data from several technologies that makes this condition assessment the best method of asset management.

. IR is most useful in the assessment of the transformer support systems. These below listed support systems are the cause of many transformer failures.

The systems include:

- Bushings and terminations
- Lightning Arrestors
- Load Tap Changers
- Isophase Bus and Duct work
- Duct Heaters
- Desiccant
- Oil preservation systems/nitrogen blanket/conservator
- Cooling System, including:
- Pumps
- Fans
- Controls, contactors, heaters, breakers, wiring and terminations
- Radiators & Valves

These support systems must be cared for and monitored as one would any critical plant system. The life of the transformer depends on them. Several images below show the usefulness of IR for transformer CA.

Figure 10: IR Image of a FAILING Load Tap Changer (LTC)

Load Tap Changers are an electrical device, very similar to a circuit breaker that gets a lot of use. There are contacts inside of tap changers that both wear out and begin to overheat or contacts which begin to overheat due to high resistance and excessive carbon from arcing. LTC's should be 5 to 10 C cooler than the main tank at the same elevation. The profile temperature, top to bottom should not exceed 10C. There are cases where the combination of high ambient temperatures and recent running of the cooling system make the LTC appear hotter than normal. Figure 10 is an IR image of a problematic load tap changer. Performing an off-line evaluation of an LTC requires a good deal of labor and is time consuming. When we find such problems with IR, we usually recommend further diagnostics such as DGA of an oil sample or acoustic/electric testing mentioned above.

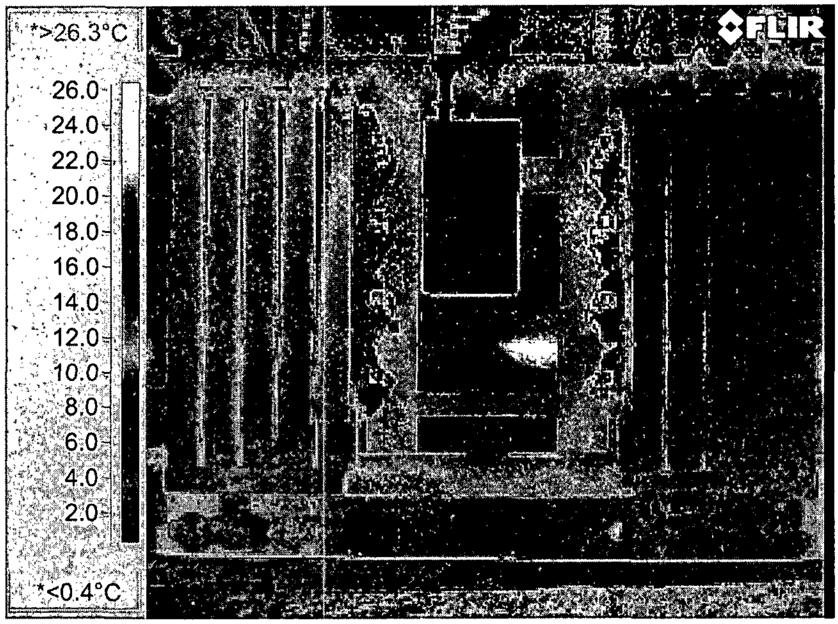


Figure11: IR Image of a FAILING Cooling System

Figure 11 is an IR image of a cooling system that is only working at 50%. A 50% loss of cooling is critical during the summer and in high loading conditions. The cooler on the right is operating normally with some overheating of fan motors. The left side cooler is not working at all. The image indicates no flow thru this cooler. Remember from all training given on the cooling system, the normal flow in a cooler is top to bottom whether pumped or natural flow. The cause of this anomaly was a sheared key on the pump motor shaft. This allowed the shaft to rotate within the impeller. Notice the pump motor on the right is hot compared to the left side. The heating near the bottom of the left side is from back pressure, reverse flow from the other cooler.

Figure 12 shows a portion of an enclosure on a generator step-up transformer, low voltage side at the Seabrook Nuclear Generating Station [1]. Many times there is heating due to circulating current in this area, but this appeared to be a high resistance connection within the bus; most likely caused by the connection to the low side bushing.

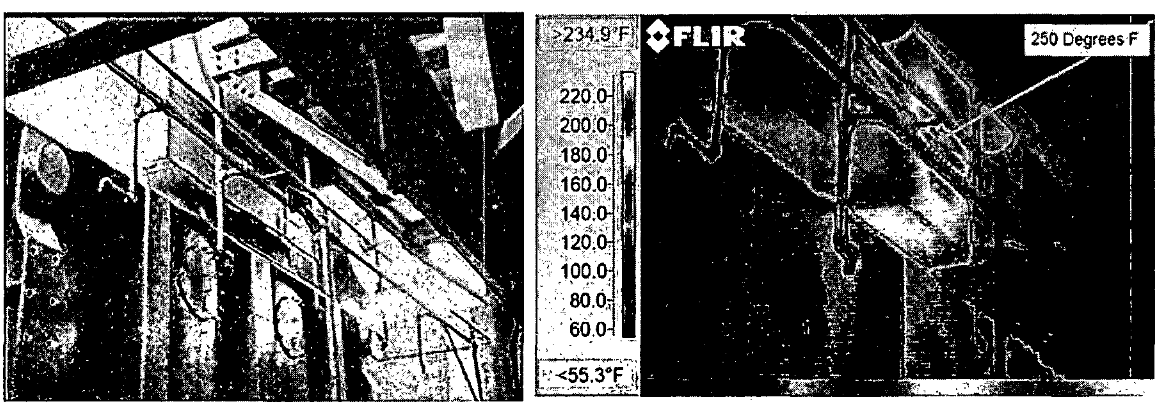


Figure 12. IR Image of a FAILING Indirect Connection. Courtesy R. Bjornson, Seabrook Nuclear Generating Station. Ref 1.

Figure 13 shows some of the internal damage due to an overheating leaf connection between the iso-phase bus and the transformer bushing. The utility estimated a $30,000,000 cost avoidance for this IR thermography find.

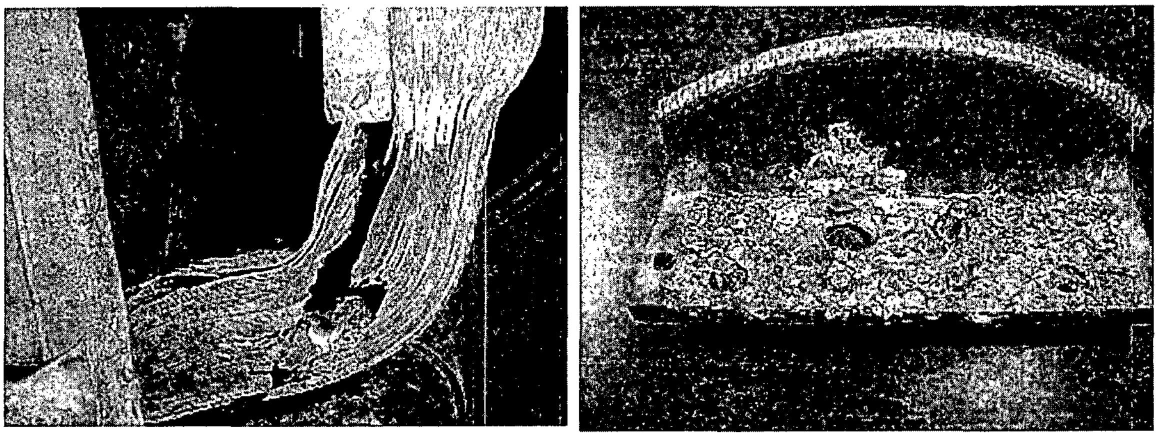


Figure 13. Overheating leaf connection approaches failure. Right hand image shows where heating has caused aluminum to melt. Courtesy R. Bjornson, Seabrook Nuclear Generating Station. Ref 1.

Figure 14 shows a primary termination to a transformer bushing at the Brunswick Nuclear Generating Station [2]. The image on the left is taken from the ground; the image on the right was taken from a man-lift. Getting different angles is very important to making a correct assessment. This appears to be a GE Type "U" bushing which only shows that indication in the image taken from the man-lift. Notice the bolting at the expansion chamber cap. The heating in the expansion chamber is caused by the hot connection.

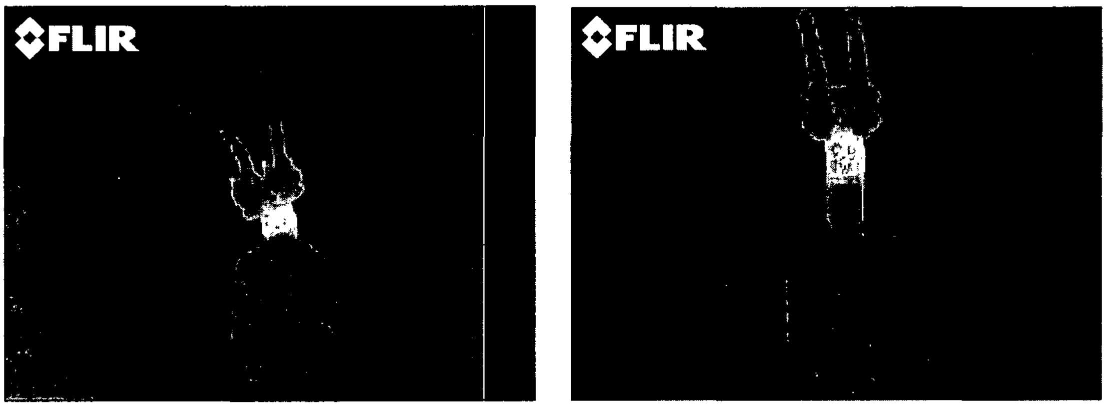


Figure 14. IR Image of a FAILING High Voltage Termination. Courtesy Mark Tallon, Brunswick Nuclear Station, CP&L Progress Energy

Figure 15 shows a primary termination to a transformer bushing. The image was taken from a man-lift. Getting different angles is very important to making a correct assessment. This is a GE Type "U" bushing, notice the bolting to the cap, similar to the above image. <u>However, this problem is the stud and expansion chamber and not the primary termination.</u>

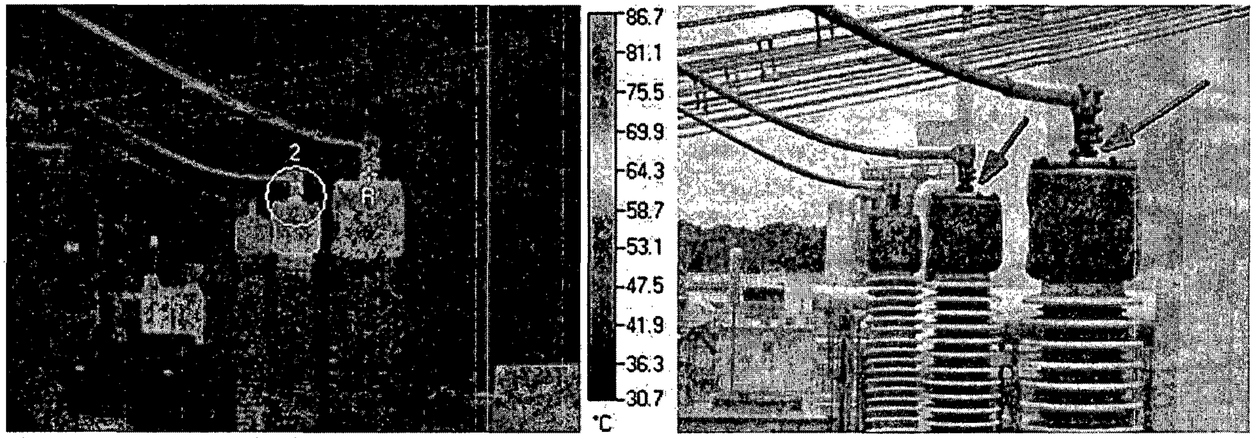


Figure 15. Primary termination to a transformer bushing showing a severe problem.

This is a 40C temperature rise measured from the initial position standing on the ground. This image from the man-lift indicated a 67C rise. The actual measured temperature at the stud entrance is 125C.

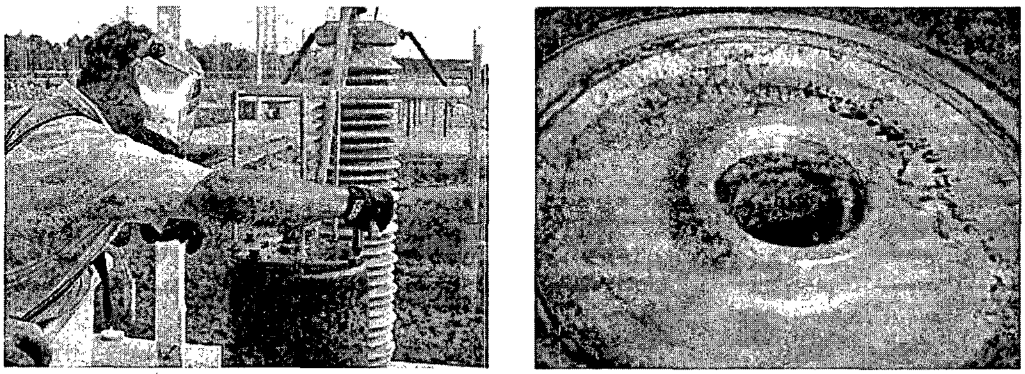


Figure 16. Substation tech dismantling the bushing cap assembly. Right hand photo shows melted threads and baked on oil deposits.

The substation tech was unable to remove the center stud due to melting. The right side image is the under side of the bushing cap showing melted threads and baked on oil deposits. Molten metal had dripped to the bottom of the conductor tube. This was very close to a catastrophic failure. A $4.5 million dollar cost benefit was assigned to this equipment save by the utility.

Vibration Analysis of Transformer Main Tank

The advantages of vibration analysis are, that it is done on-line, loaded and is non-invasive. For a transformer to withstand through-faults or switching surges including heavy load conditions, the core and windings must be securely blocked and clamped to prevent movement, shifting or distortion. Clamping pressure must be maintained to prevent core and winding looseness. Deterioration of the pressboard due to moisture or heat may cause shrinkage and looseness to occur. Trending vibration and sound level data is critical to the health of a transformer.

Acquiring Data

An accelerometer attached to a magnetic base is used to collect the signal which is stored in a vibration instrument then downloaded to a computer for analysis using standard vibration software. Eight data points are taken on each transformer. Starting on the high voltage side (Side #1) and moving counter clockwise, the data is acquired from two points on each side of the transformer. The data point locations are determined by the size and configuration of the transformer, either core form or shell form.

The spectrum of a steady-state vibration signal from the ideal transformer usually contains three dominant frequencies. First and foremost 120 Hz is detected which is 2 times line frequency of 60 Hz. During the positive and negative shifts of the 60 Hz, 2 pressure waves are created per cycle which travel to the wall of the transformer thru the core, blocking and oil, this pressure wave is 120 Hz. Also detected are the harmonics of the 120 Hz, which are 240, 360, 480 and 600 Hz.

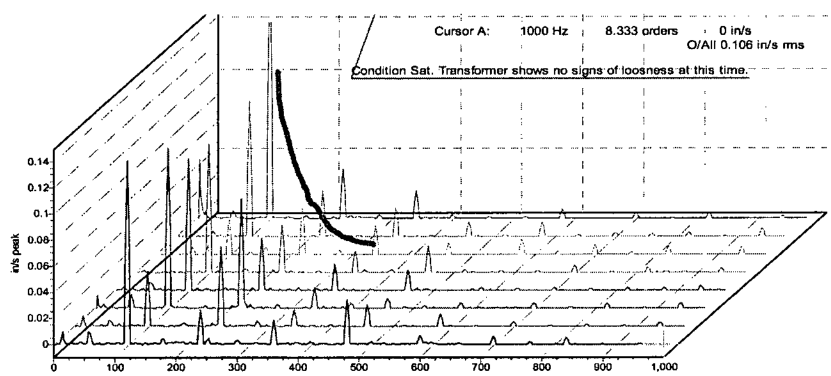
Analyzing Data

Recognizing the symptoms of core or blocking looseness is imperative in diagnosing transformer condition. Original methods of transformer vibration technology application considered only amplitude. This was based on severity criteria in inches per second, but the research has shown that frequency shifts point toward core and winding looseness regardless of amplitude.

It is very difficult to warrant internal inspections based on vibration and sound level alone. There have been two internal inspections of transformers which exhibited signs of looseness. The first one was done at a generating station on a GSU. The data on this unit is not available as this was done over 10 years ago and the data has been lost. This unit had a bushing failure after the diagnosis of looseness (unrelated). During the bushing replacement an internal inspection was ordered due to the vibration report. The findings of the internal inspection revealed blocking which was laying on the bottom and many loose bolts as well. Repairs were made by the utility with the assistance of the factory. The second internal inspection was done due to a customer complaint. The data for this inspection is case study 4 below. There is another transformer which has been removed from service and is sitting in a storage yard. There were plans to dissect this unit, but budget will not allow it. This is case study 3. Below are more case studies showing transformer and pump issues.

Transformer Vibration Analysis Case Studies

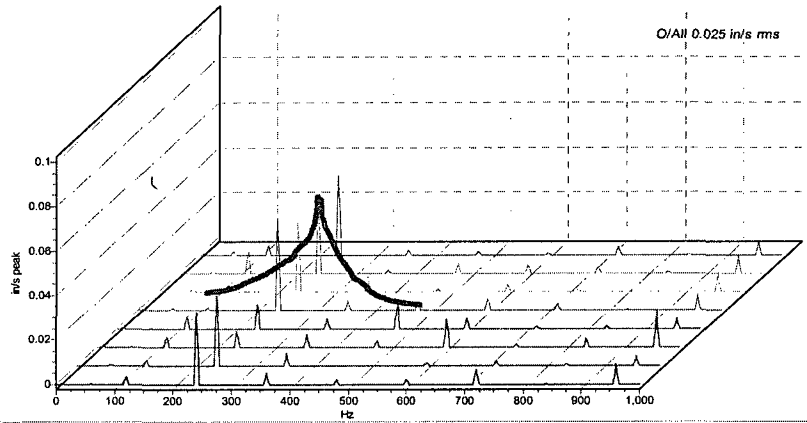
Case study #1 whose vibration waterfall plot is shown in Figure 17 is a fully loaded GSU. It is a 408/456 MVA unit with 1190 MW, the average sound level is 91 dbc. Notice that the 120 Hz is greater than the 240, 360 or 480 Hz and the left axis maximum is set at .15 ips. The sound level is taken at the same time the vibration is taken. Normal sound levels for a non-GSU transformer are approximately 70 to 80 db. The sound level is taken in C weighted to capture all of the 120 Hz which is being produced by the normal transformer action.



Side Four	**Right**	**Vel Freq 1000 Hz**	**9/20/2005 8:04:21 AM**	**O/All 0.106 in/s rms**	**7200 RPM**
Side Four	Left	Vel Freq 1000 Hz	9/20/2005 8:03:34 AM	O/All 0.056 in/s rms	7200 RPM
Side Three	Right	Vel Freq 1000 Hz	9/20/2005 8:03:10 AM	O/All 0.107 in/s rms	7200 RPM
Side Three	Left	Vel Freq 1000 Hz	9/20/2005 7:59:36 AM	O/All 0.08 in/s rms	7200 RPM
Side Two	Right	Vel Freq 1000 Hz	9/20/2005 7:58:45 AM	O/All 0.077 in/s rms	7200 RPM
Side Two	Left	Vel Freq 1000 Hz	9/20/2005 7:49:38 AM	O/All 0.039 in/s rms	7200 RPM
Side One	Right	Vel Freq 1000 Hz	9/20/2005 7:49:16 AM	O/All 0.08 in/s rms	7200 RPM
Side One	Left	Vel Freq 1000 Hz	9/20/2005 7:48:52 AM	O/All 0.144 in/s rms	7200 RPM

Figure 17. Case Study #1. Normal shell form transformer waterfall vibration plot. The hand drawn red line shows the normal slope of a tight transformer.

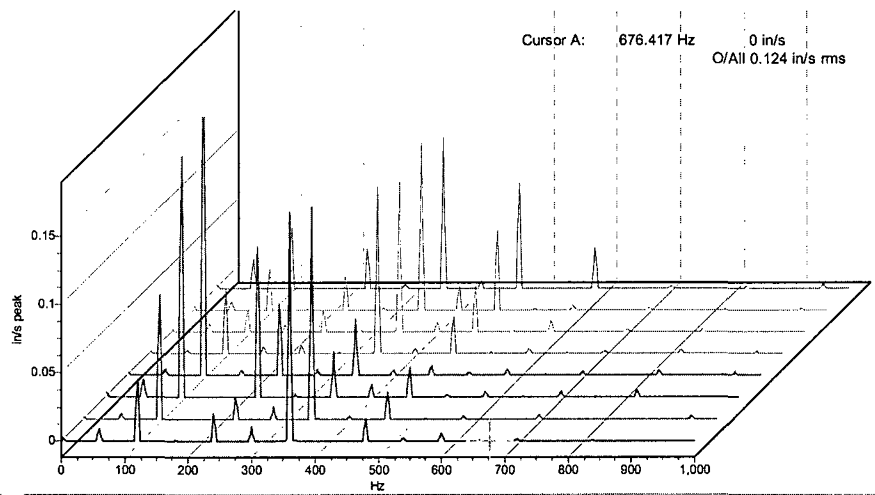
Case study #2 is a 1667 KVA unit (very small) Load at the time of this test was unknown, but average load is 80 to 120 amps. Notice that the 120 Hz has dissipated and the energy in the spectrum has shifted to the right to 240 Hz. This gives an abnormal slope shown by the hand drawn red line in the plot of Figure 18 and indicates looseness. Average sound level during this test is 81db. The sound level on this unit was 8 to 12 db higher than on similar units at the same load. This condition occurs in approximately 2% of all transformers. An SFRA test was done on this unit which indicated some abnormalities.



Side #4 85.7db	**Right**	**Vel Freq 1000 Hz**	**1/20/2004 11:21:16 AM**	**O/All 0.025 in/s rms**	**7200 RPM**
Side #4 85.7db	Left	Vel Freq 1000 Hz	1/20/2004 11:20:48 AM	O/All 0.023 in/s rms	7200 RPM
Side #3 78.9 db	Right	Vel Freq 1000 Hz	1/20/2004 11:20:04 AM	O/All 0.017 in/s rms	7200 RPM
Side #3 78.9 db	Left	Vel Freq 1000 Hz	1/20/2004 11:19:32 AM	O/All 0.013 in/s rms	7200 RPM
Side #2 82 db	Right	Vel Freq 1000 Hz	1/20/2004 11:19:02 AM	O/All 0.031 in/s rms	7200 RPM
Side #2 82 db	Left	Vel Freq 1000 Hz	1/20/2004 11:18:33 AM	O/All 0.024 in/s rms	7200 RPM
Side #1 77 db	Left	Vel Freq 1000 Hz	1/20/2004 11:16:51 AM	O/All 0.024 in/s rms	7200 RPM
Side #1 77 db	Right	Vel Freq 1000 Hz	1/20/2004 11:17:47 AM	O/All 0.027 in/s rms	7200 RPM

Figure 18. Case study #2 waterfall vibration plot. Energy is shifted to higher frequencies in this core form transformer. The red line is hand drawn to show abnormal slope due to energy shift of a loose transformer.

Case study #3 shown whose vibration waterfall plot is shown in Figure 19 is a 100 MVA unit loaded at 6 MW. The energy shift has moved to 360 Hz with some 480 Hz starting to show up. Notice that where the most of the energy is at 120 Hz the 360 is lower. The average sound level on this unit was 92 db, which brought on many complaints from homeowners in the surrounding area. Due to the noise related complaints this transformer was inspected using vibration and sound level. The combination of sound level and the energy shift made this an easy candidate for inspection. This unit was shipped offsite for inspection and tightening. The report from the factory indicated many loose clamping bolts.



4R	**Tangential**	**Vel Freq 1000 Hz**	**2/20/2002 11:57:46 AM**	**O/All 0.124 in/s rms**	**<set RPM>**
4L	Tangential	Vel Freq 1000 Hz	2/20/2002 12:05:05 PM	O/All 0.129 in/s rms	<set RPM>
3R	Tangential	Vel Freq 1000 Hz	2/20/2002 12:04:07 PM	O/All 0.15 in/s rms	<set RPM>
3L	Tangential	Vel Freq 1000 Hz	2/20/2002 12:02:37 PM	O/All 0.169 in/s rms	<set RPM>
2R	Tangential	Vel Freq 1000 Hz	2/20/2002 12:01:44 PM	O/All 0.096 in/s rms	<set RPM>
2L	Tangential	Vel Freq 1000 Hz	2/20/2002 12:01:12 PM	O/All 0.084 in/s rms	<set RPM>
1L	Tangential	Vel Freq 1000 Hz	2/20/2002 11:56:19 AM	O/All 0.101 in/s rms	<set RPM>
1R	Tangential	Vel Freq 1000 Hz	2/20/2002 12:00:11 PM	O/All 0.105 in/s rms	<set RPM>

Figure 19. Case study #3 vibration waterfall plot. Energy is shifted to the right in this core form transformer.

Figure 20 shows the vibration waterfall plot of case study #3.1, the sister unit to the transformer in Case Study #3 above. The load on this 100 MVA unit at the time for this test was 6 MW, the same as the above unit. The average sound level on this unit was 68 db. This spectrum is shown as a comparison. At the time of this test, the entire load was shifted from the above transformer to this one. There was very little increase to the sound or vibration from this unit. The substation became almost silent. The waterfall plot in Figure 20 shows a tight transformer signature.

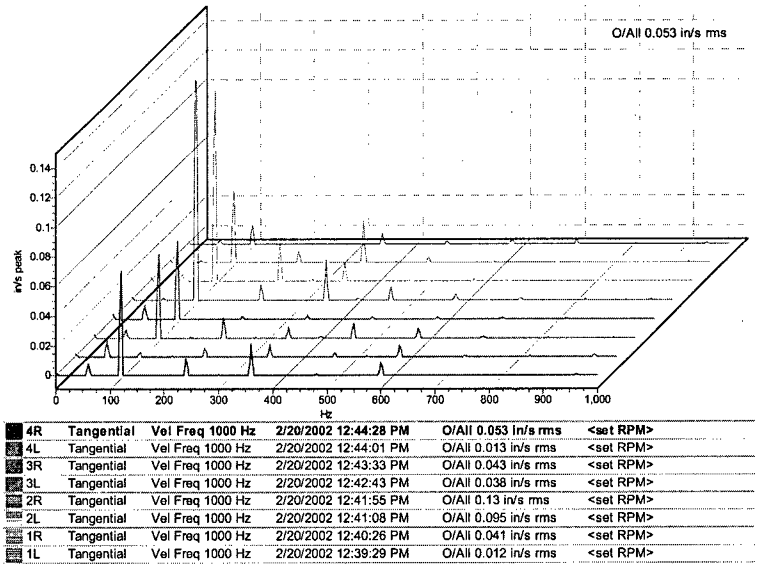


Figure 20. Case study #3.1, sister transformer to case study #3. Waterfall plot shows a tight transformer.

Pump condition is also analyzed by vibration

Below are two examples of pump vibration. The first one is normal and the second one is in severe danger of a failure and the good possibility of metal particles being pumped into the transformer. The arrow indicates the first level of alarm at 0.1 ips.

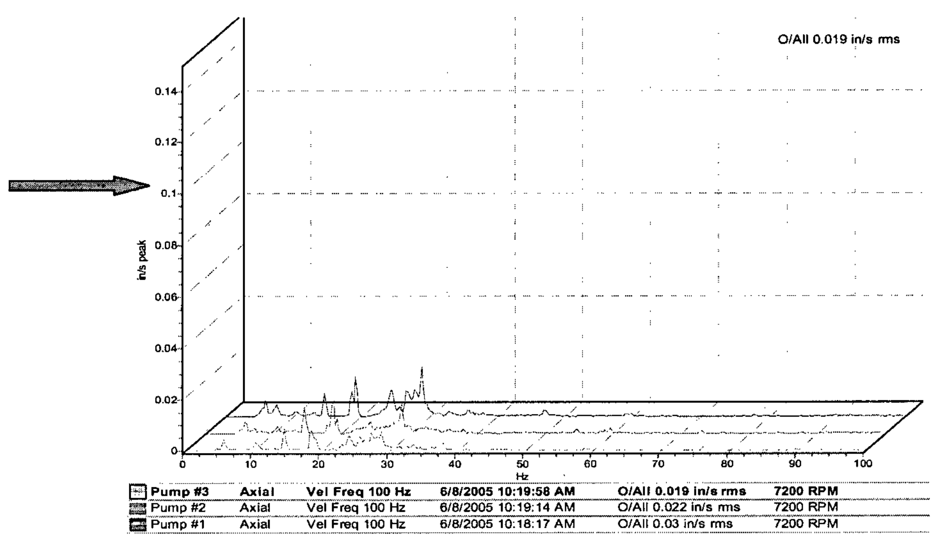


Figure 21. Waterfall vibration plot of normally operating cooling oil circulating pumps.

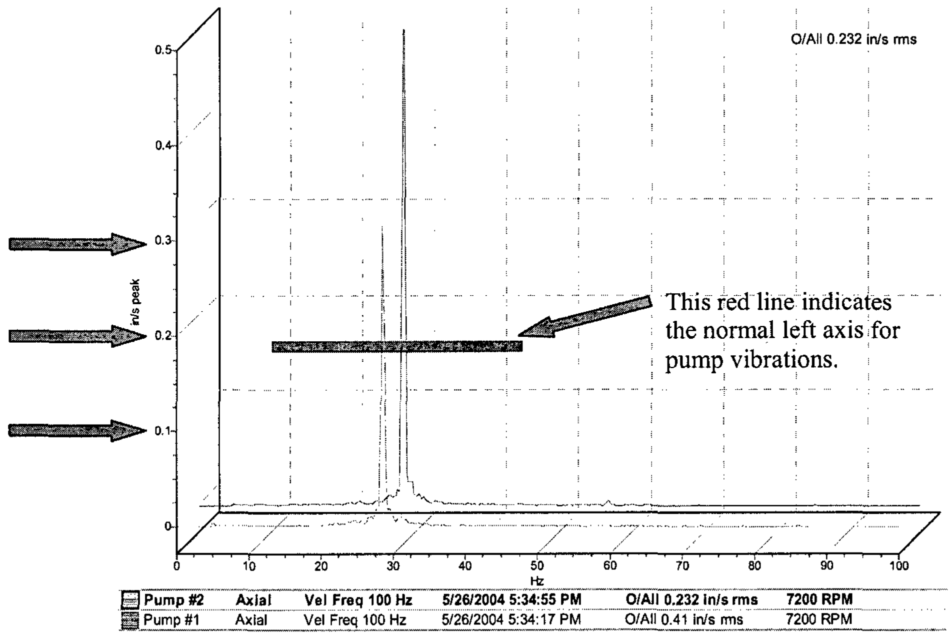


Figure 22. Waterfall vibration plot of abnormally operating cooling oil circulating pumps.

The arrows at the left indicate the three alarm levels used in axial pump vibration. Notice that pump #1 in Figure 22 has exceeded all three levels, while pump #2 is approaching the highest severity level. This condition is unacceptable and should be addressed.

Identification of Incipient Faults using Dissolved Gas Analysis (DGA)

A very brief explanation of DGA is included in this paper to complete the thought process of L2CA.

Gases generated are a function of the material involved (oil and/or insulation) and the type, source and severity of the problem. 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. Generally, where decomposition gases are formed principally by ionic bombardment, there is little or no heat associated with low energy discharges and corona.

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. (Dornenberg, Rogers, GE, IEEE, IEC and Duval methods) The detection of certain gases generated in an oil-filled transformer in service is frequently the first available indication of a malfunction that may eventually lead to failure if not corrected. Arcing, corona discharge, 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.

Key gas indicators of Fault Conditions in Transformers

- **ARCING IN TRANSFORMER OIL--ACETYLENE**

Arcing in transformer oil is revealed by the presence of the key gas ACETYLENE.

Hydrogen	60.0% of Combustibles
ACETYLENE (KEY GAS)	30.0% of Combustibles
Methane	5.0% of Combustibles
Ethane	1.6% of Combustibles
Ethylene	3.3% of Combustibles

- **CORONA IN TRANSFORMER OIL--HYDROGEN**

Corona in transformer oil is revealed by the presence of the key gas HYDROGEN.

HYDROGEN (KEY GAS)	86.0% of Combustibles
Methane	13.0% of Combustibles
Carbon Monoxide	0.2% of Combustibles
Ethane	0.5% of Combustibles
Ethylene	0.2% of Combustibles
Acetylene	0.1% of Combustibles

- **OVERHEATING OF TRANSFORMER OIL--ETHYLENE**

Overheating in the transformer is revealed by the presence of the key gas ETHYLENE.

ETHYLENE (KEY GAS)	63.0% of Combustibles
Ethane	17.0% of Combustibles
Methane	16.0% of Combustibles
Acetylene	Trace
Misc. Gases	Trace

- **OVERHEATING OF CONDUCTOR (Cellulose Breakdown)—CARBON MONOXIDE**

Overheating of an oil submerged paper insulated conductor in the transformer is revealed by the presence of the key gas CARBON MONOXIDE.

Oil quality testing

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

Dielectric Strength

This test determines the ability of oil to withstand a voltage stress, thus indicating its value as an insulating medium and perhaps the existence of contamination and deterioration by-products.

Obtain the oil sample and perform ASTM D-877 or D-1816 test. The choice of test depends on the type and high voltage rating of the transformer. The D-1816 uses rounded electrodes and a stirrer during the test. It is primarily for tests on filtered, degassed, and dehydrated oil prior to and during filling of transformers rated 230 kV and above. The D-877 is for most all other equipment. It is done using flat electrodes, unstirred sample. Breakdown readings should be analyzed based on the type of transformer and its voltage rating.

Power Factor / Dissipation Factor

Increase in this factor is indicative of a growing problem. Percent power factors exceeding 0.5% or rapid increases warrant further investigation. Normal test uses 10kV applied to the specimen. A watts loss is obtained to calculate the % PF.

Interfacial Tension (IFT)

This test checks for the presence of soluble polar compounds and products of deterioration which may indicate a potential threat to the future operating condition of a transformer.

Samples can be tested in the field, but more accurate results can be obtained in the lab. Values below 21 dyne/cm may require corrective action. Acidity level should be determined to correlate IFT readings.

Acidity, Total Acid Number (T.A.N.) or (Neutral Number)

This test measures the amount of oxidation that has taken place in the oil. Excessive oxidation of the oil produces oxidative soaps or sludge and at the same time its acidity level rises. The test checks for the presence of acidic degradation constituents which may indicate a potential threat to the future operating condition of a transformer.

Samples can be tested in the field, but more accurate results can be obtained in a lab. Neutralization Number above 0.3 mg KOH/g of oil may require corrective action. (Neutral Number is equal to the weight in milligrams (mg) of potassium hydroxide (KOH) required to neutralize the acid in one gram of oil). IFT value should be determined to correlate acidity level.

Color

This test is indicative of the relative change in oil during service, prophetic of changes in operating condition of a transformer or the existence of an incipient fault, prior to being detectable by many other available tests.

Samples can be tested in the field, but more accurate results can be obtained in a lab. A high color number, above 4.0, occurs in combination with the presence of extreme oil deterioration or contamination or both. Under normal condition changes occur over long periods of time. Rapid changes are indicative of a dramatic change in operating condition. Color numbers run 0 through 10. A 0 number is clear, 4 is amber, and 10 is black.

Moisture (Water Content)

Check for the presence of free water and determine the level of dissolved moisture in transformer's oil.

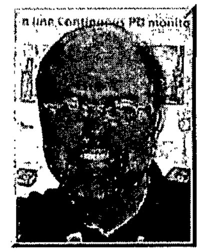
A correlation exists between dissolved moisture level in oil and the moisture content of the insulation system, based on temperature.

Summary

Implementing an L_2CA process of your aging electrical system is the key. The L_2CA process is only as good as the commitment by senior management. Without support from the management team, the process will not succeed. A successful program must have continuity of personnel. Prior to the retirement or promotion of any key individual, measures must be taken to replace in kind and transfer the knowledge to the new people.

This is a commitment that is needed more now than ever. The two greatest problems facing the electric power industry today is aging workforce and aging transformers. This needs to be addressed now! Waiting is putting your system and the electrical infrastructure at risk.

Authors Biographical Sketches



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Providing Services, Training & Products to the Electric Power Industry

Areas of Expertise

- Development and Implementation of the Substation Predictive Maintenance Program
- Course Instructor for SPdM & Infrared Thermography
- Consulting and Training Services for Program Evaluation
- PdM Template Development
- Data Acquisition and Analysis for Condition Assessment using:
  Partial Discharge, Vibration, Sound Level, Infrared, Corona, and 'Condition Assessment' processes for large oil filled power transformers and associated substation equipment.

Summary

Mr. Jon L. Giesecke is an ITC level III thermographer and is the lead thermographer for JLG Associates, LLC. He also serves on the board of directors of the International Society of Professional Thermographers, Inc. (ISPoT), and chairs one of their committees. He has over 14 years of experience in transformer/substation predictive maintenance and over 30 years in substation maintenance.

Prior to forming JLG Associates LLC, Mr. Giesecke was employed by the Electric Power Research Institute's solution division, (EPRI Solutions) as a senior project manager in the Substation Predictive Maintenance business area.

As Senior Project Manager for EPRI Solutions, some of his responsibilities included: the development and implementation of the Substation Predictive Maintenance Program (SPdM) at numerous electric utilities in the U.S. and abroad; development and instruction of the SPdM Course; lead instructor for portions of the EPRI Transformer Performance Monitoring and Diagnostics Course and the EPRI Substation/Switchyard Predictive Maintenance Course; He has provided training services and consulting to evaluate maintenance responsibility and advanced programs applied to switchyard/substation components. Jon has been a guest instructor for the Infrared Training Center (ITC) in the area of substation infrared. He has been instrumental in the data acquisition and analysis of that data at many nuclear facilities, aiding the nuclear power industry in creating a response to INPO's SOER 99-01 and 2002-03. He is also responsible for PdM template development for fossil and nuclear applications.

His career in electrical maintenance spans over 32 years with Exelon, formerly Philadelphia Electric Company (PECO) During his career with PECO, he held many positions, from helper to foreman, including 4 years of Doble testing, 2 years in Outage Planning, 2 years as Training Coordinator for the Nuclear Group, 2 years as Turbine-Generator Foreman.

A tour of duty with the US Navy during the Viet Nam war as a radioman and teletype repairman was the beginning of Jon's high tech experience.

Education and Certifications

- USN Teletype Repair Training 1967
- USN Cryptographic Procedures Training 1967
- Electrician/Electrical Maintenance Training; 3rd , 2nd and 1st class, PECO Energy Co. 1969-71
- Nuclear Qualification GET/GRT Training, PECo Energy 1970-1995
- Supervisory Developmental Academy, American College, Bryn Mawr, PA. 1990
- EPRI Transformer Performance Monitoring and Diagnostics Course 1993, 1995
- EPRI Substation Predictive Maintenance Course 1995, 1997, 2000
- Penn State College of Engineering (3.0 CEU's) SPdM Course 2004
- EPRI Level I Infrared Thermography 1993
- EPRI Level II Infrared Thermography 1996
- ITC Level II Infrared Thermography (requal) 2000
- ITC Level III Infrared Thermography 2003
- Advanced IR Thermography Workshop
- Ultrasonic/Partial Discharge in transformers Level I 1993
- Ultrasonic/Partial Discharge in transformers Level II 1995
- Introduction to Vibration Analysis I 1993
- Advanced Vibration Training on VB Series Analyzer 2001
- Advanced Sound Level Analysis II 1994
- Corona Detection and Assessment using DayCor Technology 2000
- Fundamentals of Acoustic Measurements, Bruel & Kjaer 1993
- Transinor Leakage Current Monitor (LCM) 2001 (On-line lightning arrestor condition)
- Advanced Dissolved Gas Analysis 1994, 1996, 2000
- Transformer Moisture Analysis & Monitoring 2004
- Continuing Education Courses - 2006
- PowerPD's advanced PD workshop, 2006

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Bob is a graduate of the U. of Missouri-Rolla with a BS in Physics, and a PhD in Physics from the U. of Wisconsin-Madison. He began the first IR thermography seminar at the U. Wisconsin Extension in 1978. He co-founded the Thermosense Conference in 1978 with two other colleagues from the UW. In 2000 he founded the Inframation Conference, the largest annual IR conference for thermographers. Bob holds an ASNT NDT Level III in Thermal Infrared and an EPRI Level III in IR thermography. He has published numerous technical papers on infrared thermography applications, as well as contributing chapters to textbooks such as Applied Thermal Design and the Encyclopedia of Optical Engineering. Bob has over 30 years experience in infrared thermography applications and training. He manages the company's training programs, engineering consulting services, and applications feasibility studies. With years of practical experience at a large electric utility and at a large aerospace defense company, Dr. Madding has a unique combination of both technical product and applications knowledge and a "school of hard knocks" understanding of thermographer issues.

Bob's research experience includes designing, building and field testing, including optical signature measurement, prototype articles of a proprietary nature at McDonnell Douglas. While at the University of Wisconsin, he worked in the Environmental Monitoring and Data Acquisition Group monitoring heated water discharges from electric power plants using airborne IR thermography. While at Maintenance and Diagnostics, an EPRI contractor, he developed advanced applications of thermography for condition monitoring. At the Infrared Training Center, Bob has written software for electrical load correction of hot spot temperature rise, power loss calculator that will estimate electrical resistance on problematic operating equipment such as oil-filled circuit breakers, and other IR applications software to make the professional thermographers' life more rewarding.