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In the Matter of:	Entergy Nuclear Operations, Inc. (Indian Point Nuclear Generating Units 2 and 3)
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Entergy

FLEET ENGINEERING GUIDE

EN-EE-G-001 Rev. 2 Effective Date: 03-31-2011

Large Power Transformer Inspection Guidelines

Applicable Sites		Effective Date Exception	Applicable Sites		Effective Date Exception
ANO	☒		PNPS	☒	
GGNS	☒		RBS	☒	
IPEC	☒		VY	☒	
JAF	☒		WF3	☒	
PLP	☒		HQN	☒	
	☐			☐	

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Site: HQN

Requirements and Revision Summary

Revision No.	Changes
0	Original issue
1	Rewrite of Attachment 6.8 and minor editorial changes
2	**Update for SOER 10-1 Recommendations, revised applicable oil quality testing and acceptance discussions for consistency with ANSI C57.106-2006, clarified responsibilities, added low temperature power factor testing note and minor editorial changes**

TABLE OF CONTENTS

1.0 PURPOSE

1.1 The intent of this guide is to provide methods for performing inspections of large power transformers when degraded conditions are detected. This guide contains an outline and checklists for assisting with internal inspections and includes applicable industry and operating experience, vendor recommendations, and oil processing and handling practices.

1.2 For the switchyard equipment, this guide can be used to keep the Maintenance and Operations organizations informed and assist the offsite power service provider if needed.

1.3 This guide may be used as a source of information for Engineering review of work documents for large power transformers [SOER 10-1].

2.0 REFERENCES

2.1 ANSI/IEEE C57.106 -2006 – “Guide for Acceptance and Maintenance of Insulating Oil in Equipment”

2.2 ANSI/IEEE C57.12.90 - 2006 - “Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers”

2.3 ANSI/IEEE C57.104-1991 – “IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers”

2.4 Myers Transformer Maintenance Guide

2.4.1 Chapter 6 - “Basic Protective Maintenance Practice for Oil – Insulated Transformers”

2.4.2 Chapter 7 - “Corrective Maintenance Procedures for Oil Insulated Transformers”

2.5 Entergy Operations Inc., Arkansas Nuclear One Transformer Guide of Inspections

2.6 NMAC - “Large Power Transformer Reliability”

2.7 Equipment Manufacturer's Instruction Manuals

2.8 EN-IS-102, “Confined Space Program”

2.9 EN-MA-118, “Foreign Material Exclusion“
Entergy Site Specific PM Procedures

2.11 INPO SOER 10-1, “Large Power Transformer Reliability”

2.12 EPRI 1002913, “Power Transformer Maintenance and Application Guide”

2.13 NEIL Transformer Testing Flowchart & Guidelines

3.0 DEFINITIONS

3.1 Acceptable Oil - Used oil which has been determined to be acceptable for use in a particular class of equipment.

3.2 Caution - Potential hazard, which could result in a minor injury or asset damage.

3.3 Close-In Through Fault - A fault that is located near enough to the transformer to cause near maximum fault current to flow.

3.4 Contamination - Foreign substances that are not products of oxidation of the oil.

3.5 Danger - Immediate hazard, which will result in severe/fatal injury or asset damage.

3.6 Deterioration - Effect of oxidation, contamination, and elevated temperatures on insulating oil, which increases the rate of decomposition or breakdown of the oil.

3.7 Dissolved Combustible Gas (DCG) - Combustible gases that are dissolved in the oil. It is determined by an analysis made on the oil.

3.8 Dominant Functional Failures – Failures that have adverse safety, environmental, system, customer or financial consequences.

3.9 Equilibrium - Condition resulting in a stable, balanced, or unchanging system.

3.10 Equivalent Total Combustible Gas (ETCG) - This quantity is the total of all combustible gases that would be in the gas space if the system were at equilibrium. It is determined by a calculation based on the concentrations of combustible gases dissolved in the oil. The gases dissolved in the oil are determined by Dissolved Gas Analysis (DGA).

3.11 Inhibitor - Substance added to an insulating fluid to improve its oxidation stability and its resistance to deleterious attack in an oxidizing environment.

3.12 Overheating - Operation of a transformer in a manner that causes operating temperatures to be in excess of the design temperature maximum values.

3.13 Overload - Output of current, power, or torque in excess of the rated output of a device on a specified rating basis.

3.14 Oxidation - Oil deterioration that occurs when oxygen reacts with the oil.

3.15 Point of Contact (POC) - Person responsible for oversight, establishment, and implementation of the guidelines of this guide for Switchyard and Transformer yard maintenance activities.

3.16 Purge - Process of percolating nitrogen into the oil through the drain valve, located at the bottom of the oil-filled equipment, allowing the escaping gas to pass into the atmosphere through a vent. Percolating nitrogen into the oil will increase the rate at which the dissolved gases will be transferred to the gas phase.

3.17 Reactive Equipment - Reactors, regulators, transformers, etc.

3.18 Reclaiming - Removal of chemical contaminants and degradation products from used insulating liquids by chemical and physical means.

3.19 Reconditioning - Involves the removal of insoluble contaminants, moisture, and dissolved gases from new or used insulating liquids and is also called oil processing.

3.20 Static Discharge - Source of ignition that can result when a potential difference is created by friction between two surfaces. Oil flowing through an ungrounded hose can produce a static discharge that produces a spark, which can ignite combustible gases if sufficient oxygen is present.

3.21 Total Dissolved Combustible Gases (TDCG) - Quantity represents the total of all combustible gases that are dissolved in the oil. It is determined by an analysis made on the oil.

3.22 Total Dissolved Gases (TDG) - Total of all gases (combustible and non-combustible) dissolved in the oil. This quantity is determined by a chemical analysis made on the oil known as a Dissolved Gas Analysis.

3.23 Through Fault – A fault where the fault current flows through a transformer. This fault can be of any magnitude.

4.0 RESPONSIBILITIES

4.1 **Manager, System Engineering or Program and Components** (depending on site) - Responsible for the implementation of the Large Power Transformer Inspection Guidelines.

4.2 **Electrical System Engineering or Component Engineering Supervisor** (depending on site) - Responsible for oversight of the Large Power Transformer Inspection Guidelines. This includes ensuring that the inspection attachments are utilized to determine the condition of a transformer that has experienced a transient and the engineer responsible for large power transformer has evaluated the inspection and test results. Provide proper notification of the inspection and test results to site management.

4.3 **Component or System Engineer** - (depending on site) - Responsible to identify which inspection attachment(s) should be utilized, ensure qualified personnel perform the inspection and testing as applicable by site procedures, and support maintenance in the implementation of the inspection, including Engineering review of site work documents, when requested. Review the inspection and test results, and provide recommendations to his Supervisor on the condition of the transformer being inspected.

4.4 **Maintenance Department** - Responsible to perform the inspection and testing identified by the Component or System Engineer in accordance with the site maintenance procedures. Provides a copy of the inspection and test results to the Component or System Engineer for evaluation.

5.0 DETAILS

5.1 Scope and Precautions

5.1.1 This guide includes an outline and checklists that can be used for large power transformers, Unit Auxiliaries and Startups, as well as any additional guidance for switchyard large power transformers and voltage regulators. This guide contains instructions for inspections, including multiple checklists for normal inspection activities, and different types of inspections due to the various conditions the units may experience. It includes applicable industry operating experience, vendor recommendations, and contacts. This guide includes the handling of oil that has high combustible gas content and all of their storage requirements.

5.1.2 This guide does not address all possible safety issues associated with its use. It is the responsibility of the supervisor and craft personnel to follow all Entergy Nuclear (EN) and site-specific safety practices and those listed within the manufacturer's instruction manual.

5.1.3 Information in Attachments 6.1 through 6.8 was obtained from Entergy Operations Inc., Arkansas Nuclear One Transformer Guide of Inspections, and revised for consistency with ANSI C57.106-2006.

CAUTION

1. Employees should be aware of the dangers of entering a transformer without proper ventilation. After the transformer has been drained, have Safety perform appropriate Confined Space Entry tests.
2. Employees should be aware of dangers of performing electrical tests to transformers when highly flammable gases may be present in the transformer.

5.1.4 Perform all items as outlined in the appropriate checklist and record data as necessary. Information in Attachments 6.1 through 6.8 was obtained from Entergy Operations Inc., Arkansas Nuclear One Transformer Guide of Inspections, and revised for consistency with ANSI C57.106-2006.

- Internal Inspection
- Exposure to Internal or Through Faults that Cause a Trip
- Exposure to Close-In Through Faults
- Exposure to Overloads
- Exposure to Overheating
- Electrical and Mechanical Problems Including Sudden Significant Oil Leaks

5.1.5 Perform all visual inspection items for transformers and record appropriate data.

5.1.6 If any of the items are determined to be unacceptable, contact the POC or System Engineering for resolution.

5.2 Internal Inspection Preparation

5.2.1 Preparation Before Entering the Unit for Internal Inspection

5.2.1.1 Detailed work control and testing plans have been developed and reviewed.

> NOTE
>
> For transformer electrical connections that will be disturbed for the inspection or testing and require re-connection for transformer restoration to service, ensure work plans include details for connection surface preparation, connection hardware orientation and connection torque requirements. [SOER 10-1]

> NOTE
>
> Ensure plans include provisions for worker situational awareness of interactions with applicable interlocks and protective devices [SOER 10-1].

5.2.1.2 Contingency plans have been developed and approved by site management. These may include identifying and arranging to obtain a replacement unit or critical parts, operating at a reduced load, operating under an alternative transformer alignment, etc.

5.2.1.3 Verify all spare and replacement parts are on-site and available for use. This includes man-way and bushing gaskets, instrument o-rings, replacement instruments, bushings and cooling components. Confirm that any needed insulating oil, greases and gasket lubrication materials are compatible, based on current vendor information and industry operating experience [SOER 10-1].

5.2.1.4 Transformer oil processing equipment has been contracted to support transformer inspection activities.

5.2.1.5 Prior to oil removal, the oil tank used for oil storage must have a berm to contain possible oil spills prior to draining transformer to be inspected. (Contact Site Chemistry for details on berm requirement.)

5.2.1.6 Establish Foreign Material Exclusion Zone and brief personnel of the requirement, potential concerns and limitation of working inside and around an open transformer.

5.2.1.7 After oil removal and before removing any covers or fittings from the unit, make sure that the internal tank pressure is zero.

5.2.1.8 Contact Safety to obtain a confined space entry permit, as required by EN-IS-102.

5.2.1.9 The unit tank must be grounded at all times. Windings and bushings must be grounded or have static drain wires attached, except when certain electrical tests are being conducted on the unit. All oil handling equipment and vacuum pumps must also be grounded if still attached to the transformer. This will reduce the possibility of a static discharge.

5.2.1.10 Only CO_2 fire extinguishers should be provided for emergency use. Smoking shall not be permitted on top of the unit, inside of the unit or in the vicinity of the oil handling equipment.

5.2.1.11 Cord type "A/C" lights, if used, must be explosion proof and have oil resistant cords.

5.2.1.12 Before any electrical testing is performed on a unit, a review of the electrical hazards associated with this test will be conducted with the work crew.

5.2.1.13 Check the weather and select a day that appears favorable for the inspection. The weather forecast should be low humidity and no rain or showers forecasted. If work must be performed in unfavorable conditions, tenting or other protection shall be provided. Be prepared at all times to close the unit should rain threaten.

5.2.1.14 Remove the manhole covers required to do the inspection/assembly. All loose bolts, nuts and washers should be put into a container and inventoried before the unit is opened. This will minimize the possibility of them being dropped into the unit.

5.2.2 Air Supply While Working Inside the Unit

5.2.2.1 Hook up an air hose with a dry air supply connected to it. Put the hose into the top of the tank. Let the man entering the tank take this hose with him. Ensure the bottle connected to this hose is dry breathable air. The normal rate of dry air usage for a man working in the unit is about two bottles for each hour of inside work. This may require a regulator setting above 10 psi. (Dry breathable air usually has a dew point reading of -50 F).

5.2.3 Avoiding Damage

CAUTION

Before entering the transformer units, personnel should review the EN-IS-102 "Confined Space Program" and EN-MA-118, "Foreign Material Exclusion" procedures for details.

5.2.3.1 Extreme care must be taken to protect the unit insulation from damage and to prevent foreign objects from entering the unit during the internal inspection.

5.2.3.2 While the unit is open, no personnel should be permitted on top of the unit until they have emptied all pockets and checked for loose objects on them. Also, remove watches and rings, etc. Access should be limited to the minimum number of personnel required to support the work.

5.2.3.3 Personnel entering should not have loose dirt on their clothing. Clean foot covers should also be worn.

5.2.3.4 All tools must be accounted for when entering and exiting the unit. Tools must have lanyards attached to them and these lanyards should be attached to the exterior of the unit.

5.2.3.5 If any object is dropped into the unit and cannot be retrieved, the POC and System Engineer shall be notified immediately. If possible, a clean lint free drop cloth shall be used under the work area to help prevent an occurrence of this nature.

5.2.3.6 In the event of sudden weather changes, such as rain, provisions must be made for closing the tank quickly to protect the insulation from moisture.

5.2.3.7 Field drying of a unit is very expensive. Therefore, moisture entering the unit should be avoided at all times.

5.2.3.8 One person should be responsible for checking and monitoring personnel and materials entering and leaving the unit. This person should also be responsible for making sure that no objects are accidentally left inside the transformer and for limiting the length of time that the unit is left open. A record of how long the unit was open for work should be kept by the person in charge.

5.2.3.9 No blowers will be used to cool the interior of the unit during inspection or any other time the unit must be entered. This is to limit the amount of moisture entering the unit.

5.3 Internal Inspection

NOTE

Care should be taken not to step on parts easily damaged when entering the tank with the air supply hose.

5.3.1 From the outside of the unit, looking into the unit, inspect the internal parts for looseness or damage before entering the unit. If damage is obvious, notify the POC and System Engineering before entering the unit for additional inspections.

5.3.2 Perform a core ground test if the core ground lead is available at the top of the transformer. Be careful when disconnecting and connecting the core ground to and from the tank. Place a lint free cloth under the work area, as discussed in paragraph 5.2.3.5 to prevent any objects from falling into the transformer.

5.3.3 Appropriate megger should be used to determine the resistance of the core ground. For 500 volts as the test voltage, the readings should be more than 50 megohms. If the values are less than 50 megohms, contact System Engineering or POC for further actions to be taken.

5.3.4 Inspect the general condition of the core and coils and all other components.

5.3.5 Look for broken lead supports and frayed cable insulation, especially on the tapped secondary winding leads.

5.3.6 Check all metallic connections to make certain they are tight and there are no missing nuts and washers. Verify that there is no overheating.

5.3.7 Check to see if any core members have shifted. This includes core supports as well as laminations.

5.3.8 Check to see that the no Load Tap Changer (LTC) is not damaged. Move the no load tap changer through the entire range of operation to be sure it will operate properly. Inspect contacts for signs of overheating.

5.3.9 Inspect all of the parts of the Load Tap Changer to be certain there is no damage to the unit. Make a thorough check of the tap changer board between the tap changer compartment and the main tank. Be sure the board is not cracked or broken. If the tap changer can be operated without oil, manually operate it through at least several positions while going through the neutral position to assure that there is no binding in the mechanism. Follow the same procedure if the tap changer has the correct level of oil in the compartment. (Configuration and control of the position will be verified and controlled as part of the work instruction.)

5.3.10 Where possible, inspect the coils and insulation. Look for any misalignment of coil spacers indicating movement of the coil. Inspect the leads where they come out of the coils, if possible. Check all of the blocking that can be seen. Look for any looseness or discoloration of the blocking or coils.

5.3.11 Check the bottom of the tank for loose debris or parts. If any are found, try to determine where they came from. Inspect baffles and diverters installed for directing oil flow.

5.3.12 Check the inside tank walls for cracks, especially in the inside corners and interior welds and areas that may be burned or show areas of corona or stray flux activity.

5.3.13 Inspect for signs of moisture, free water, and rust inside the unit. If moisture entered the unit, it can sometimes be detected under the top covers, top of core steel, tank bottom, or in the radiator wells.

5.3.14 Check to be sure all Current Transformers are secured properly and have not shifted, causing possible damage.

6.0 ATTACHMENTS

6.1 CHECKLIST - INTERNAL INSPECTION

6.2 CHECKLIST - EXPOSURE TO INTERNAL OR THROUGH FAULTS THAT CAUSE A TRIP

6.3 CHECKLIST - EXPOSURE TO CLOSE-IN THROUGH FAULTS

6.4 CHECKLIST - EXPOSURE TO OVERLOADS

6.5 CHECKLIST - EXPOSURE TO OVERHEATING

6.6 CHECKLIST - ELECTRICAL AND MECHANICAL PROBLEMS INCLUDING SUDDEN SIGNIFICANT OIL LEAKS

6.7 INSULATING OIL ACCEPTANCE AND MAINTENANCE PRACTICES

6.8 GUIDE FOR INTERPRETATION OF GASES GENERATED IN TRANSFORMERS

6.9 INDUSTRY AND OPERATING EXPERIENCE

ATTACHMENT 6.1 **CHECKLIST - INTERNAL INSPECTION**

Sheet 1 of 1

Transformer Description: **Unit #**

Date: **Inspected By:**

- ☐ Check for unusual odor and color of the oil.
- ☐ Check to see if any core members have shifted. This includes core supports as well as laminations.
- ☐ Check for any misalignment of coil spacers indicating movement of the coil.
- ☐ Check to be sure all CTs are secured properly and have not shifted.
- ☐ Check for debris, note what type, amount, location, and take samples for analysis.
- ☐ Check for burns, resulting from arcs or stray flux on areas such as tank walls, bushing terminals, and corona shields.
- ☐ Check for winding and lead movement distortion.
- ☐ Check for loose connections to tap leads, bushings, and terminal boards.
- ☐ Check the condition of the tap changer contacts and operating mechanism, if applicable.
- ☐ Check for carbon tracking.
- ☐ Check for porcelain damage.
- ☐ Check for spongy insulation on leads.
- ☐ Check the condition of lead clamping and winding support system, including clamping.
- ☐ Check for moisture, rust on core system, and free water in the bottom of tank.

If the results of the checklist are acceptable (within manufacturer's specified limits, test equipment vendor's specified limits, or Entergy specified limits), the transformer may be returned to service.
If the results of any of these inspections are not satisfactory, consult the System Engineer or appropriate vendors to determine the corrective maintenance procedure for the transformer.

Comments:

ATTACHMENT 6.2 **CHECKLIST - EXPOSURE TO INTERNAL OR THROUGH FAULTS THAT CAUSE A TRIP**

Sheet 1 of 2

Transformer Description: **Unit #**

Date: **Inspected By:**

CAUTION

1. Before any electrical tests are performed, a Total Combustible Gas (TCG) test or Dissolved Gas Test shall be performed and results reviewed for all gas blanketed transformers.
2. If the total combustible gas is greater than 2%, blanketed transformers shall be purged prior to performing any electrical tests.

NOTE

1. If the results of the checklist are acceptable (within manufacturer's specified limits, test equipment vendor's specified limits or Entergy's specified limits), the transformer may be returned to service after DGA review by the System Engineer (or Component Engineer).
2. If the results of any of the following tests are not satisfactory, perform Attachment 6.6 – "Electrical and Mechanical Problems Including Sudden Significant Oil Leaks."

Perform at minimum and verify the following tests:

- ☐ Winding Insulation (Megger) Test
- ☐ Transformer Turns Ratio (TTR)
- ☐ Power Factor Winding and Excitation Test

NOTE

The transformer shall not be returned to service without having results of the DGA test.

- ☐ Dissolved Gas Analysis (DGA) in Oil Test

If questionable results are obtained from the DGA test, the following tests shall be performed:

1. Power Factor Tests
   - ☐ Winding Test
   - ☐ High Side Bushing Test
   - ☐ Low Side Bushing Test
   - ☐ Oil Test (power factor) (laboratory test)
   - ☐ Lighting Arrester Test

ATTACHMENT 6.2 **CHECKLIST – EXPOSURE TO INTERNAL OR THROUGH FAULTS THAT CAUSE A TRIP**

Sheet 2 of 2

NOTE

Power Factor field test results may become unreliable as component temperatures approach 32° F (0 ° C). In such cases, power factor field testing is considered optional with Engineering approval.

2. Oil Dielectric Breakdown Tests per ASTM D 877 and ASTM D1816
3. Repeat DGA test daily for one week if previous results were questionable. Additional daily testing should be considered based on transformer service history and general condition per the recommendation of the System Engineer (or Component Engineer).

   ☐ Infrared Thermography (with transformer energized)

Additional Recommended Tests

☐ Ultrasonic Noise (with transformer energized)

☐ Vibration Analysis (with transformer energized)

Results should be reviewed against transformer baseline or results obtained during the EPRI-Solution assessment.

☐ Sweep Frequency Response Analysis (SFRA)

☐ Furan Test

ATTACHMENT 6.3 **CHECKLIST – EXPOSURE TO CLOSE-IN THROUGH FAULTS**

Sheet 1 of 3

Transformer Description: **Unit #**

Date: **Inspected By:**

NOTE

Refer to Attachment 6.7, "Insulating Oil Acceptance and Maintenance Practices" for interpretation of oil dielectric test results. Refer to IEEE C57.104, "Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers" for interpretation of DGA Test results.

The following in-service inspections and tests shall be performed.

- ☐ Perform Dissolved Gas Analysis (DGA) to determine percent total of combustible gas.
- ☐ Check for unusual odor and color of the insulating oil.
- ☐ Perform Moisture in Oil Test. See Attachment 6.7, Table 1 for limits.
- ☐ Oil Dielectric Breakdown Tests per ASTM D 877 and ASTM D1816.
- ☐ Perform infrared scanning of connectors and bushings.

a. 5ºC above ambient should be recorded and tested again in 6 months.

b. 5 to 20ºC above ambient indicates trouble, but repairs are not urgent. Perform corrective service during next maintenance outage.

c. 20 to 50ºC above ambient indicates corrective action is urgent. Schedule and repair within 30 days.

d. 51ºC and above ambient indicates an emergency situation and corrective action should be scheduled immediately.

Additional Recommended Tests

- ☐ Ultrasonic Noise
- ☐ Vibration Analysis
- ☐ Sweep Frequency Response Analysis (SFRA)
- ☐ Furan Test

ATTACHMENT 6.3 **CHECKLIST – EXPOSURE TO CLOSE-IN THROUGH FAULTS**

Sheet 2 of 3

Results should be reviewed against transformer baseline or results obtained during the EPRI-Solution assessment.

NOTE

1. If the results of the checklists are acceptable (within the manufacturer's specified limits, test equipment vendor's specified limits, or Entergy's specified limits) the transformer may remain in service.
2. If the results of the tests are not questionable, the transformer may be returned to service after reviewing the DGA results.
3. If the results of these tests are not satisfactory, then perform Attachment 6.1 "Checklist - Internal Inspection."

CAUTION

Before any electrical tests are performed, a Total Combustible Gas (TCG) test or Dissolved Gas in Oil Field Test shall be performed for all gas-blanketed transformers. If the total combustible gas is greater than 2%, blanketed transformers shall be purged prior to performing any electrical tests.

If questionable results are obtained from the preceding inspections or tests, the following out of service (OOS) tests shall be performed.

☐ Winding Insulation (Megger) Test

☐ Transformer Turns Ratio (TTR)

☐ Power Factor Testing

1. Winding Tests
2. Excitation Tests
3. High side voltage bushings
4. Low side voltage bushings
5. Lightning arrestors
6. Oil test (power factor) (laboratory test)

NOTE

Power Factor field test results may become unreliable as component temperatures approach 32° F (0 ° C). In such cases, power factor field testing is considered optional with Engineering approval.

ATTACHMENT 6.3 CHECKLIST – EXPOSURE TO CLOSE-IN THROUGH FAULTS

Sheet 3 of 3

- ☐ Dissolved Gas Analysis (DGA)
- ☐ Oil Dielectric Breakdown tests per ASTM D877 and ASTM D1816
- ☐ Repeat DGA in one week if previous results from the in-service test were questionable.

ATTACHMENT 6.4 **CHECKLIST - EXPOSURE TO OVERLOADS**

Sheet 1 of 2

Transformer Description: **Unit #**

Date: **Inspected By:**

NOTE

Refer to Attachment 6.7, "Insulating Oil Acceptance and Maintenance Practices" for interpretation of oil dielectric test results. Refer to IEEE C57.104 "Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers" for the interpretation of DGA Test results.

The following in-service inspections and tests shall be performed:

- ☐ Perform Dissolved Gas Analysis (DGA) to determine percent total of combustible gas.
- ☐ Check for unusual odor and color of the insulating oil.
- ☐ Perform Moisture in Oil Test. See Attachment 6.7, Table 1 for limits.
- ☐ Check bushings and arrestors for signs of overheating or damage.
- ☐ Record present and highest readings of the top oil and winding hot spot temperature gauges.
- ☐ Check for temperature differential between the main tank and the Load Tap Changer.
- ☐ Perform infrared scanning of connectors and bushings.
  - a. 5ºC above ambient should be recorded and tested again in 6 months.
  - b. 5 to 20ºC above ambient indicates trouble, but repairs are not urgent. Perform corrective service during next maintenance outage.
  - c. 20 to 50ºC above ambient indicates corrective action is urgent. Schedule and repair within 30 days.
  - d. 51ºC and above ambient indicates an emergency situation and corrective action should be scheduled immediately.
- ☐ Furan Test

Additional Recommended Tests

- ☐ Ultrasonic Noise
- ☐ Vibration Analysis
- ☐ Sweep Frequency Response Analysis (SFRA)

Results should be reviewed against transformer baseline or results obtained during the EPRI-Solution assessment.

NOTE

1. If the bushings or terminals show visual signs of overheating, bushing gaskets and o-rings must be inspected and replaced if damaged. The power factor of the bushings should also be measured.
2. If the results of the checklists are acceptable (within the manufacturer's specified limits, test equipment vendor's specified limits, or Entergy's specified limits) the transformer may remain in service.
3. If the results of any of these tests are not satisfactory, then perform Attachment 6.1 "Checklist - Internal Inspection."

CAUTION

Before any electrical tests are performed, a Total Combustible Gas (TCG) test or Dissolved Gas in Oil Field Test shall be performed for all gas-blanketed transformers. If the total combustible gas is greater than 2%, blanketed transformers shall be purged prior to performing any electrical tests.

If questionable results are obtained from the preceding inspections or tests, the following Out-Of-Service (OOS) tests shall be performed.

- ☐ Transformer Turns Ratio (TTR)
- ☐ Insulation Power Factor
- ☐ Winding Resistance
- ☐ Oil Dielectric Breakdown Test per ASTM D877 and ASTM D1816. See Attachment 6.7, Table 1 for limits.

ATTACHMENT 6.5 **CHECKLIST - EXPOSURE TO OVERHEATING**

Sheet 1 of 2

Transformer Description: **Unit #**

Date: **Inspected By:**

NOTE

1. Refer to Attachment 6.7, "Insulating Oil Acceptance And Maintenance Practices" for interpretation of oil dielectric test results.
2. Refer to Attachment 6.8, "Guide For Interpretation Of Gases Generated In Transformers" for interpretation of DGA test results.

The following in-service inspections and tests shall be performed:

☐ Check the heat exchangers and cooling fans for obstructions.

☐ Check fans for damage and operability.

☐ Check oil pumps for temperature differential between coolers and main tank.

☐ Check for temperature differential between the top and bottom of coolers.

☐ Record present and highest readings of the top oil and winding hot spot temperature gauges.

☐ Perform Dissolved Gas Analysis (DGA) to determine the Percent Total Combustible Gas.

☐ Check for unusual odor or color of insulating oil.

☐ Check the bushings and arrestors for sign of overheating or damage.

☐ Perform Moisture in Oil Test. See Attachment 6.7, Table 1 for limits.

NOTE

Refer to information in Steps (b) and (c) for urgency of corrective actions and suggestions for scheduling the corrective actions.

☐ Perform infrared scanning of connectors and bushings.

a. 5ºC above ambient should be recorded and tested again in 6 months.

b. 5 to 20ºC above ambient indicates trouble, but repairs are not urgent. (Perform corrective service during next maintenance outage.)

c. 20 to 50ºC above ambient indicates corrective action is urgent. (Schedule and repair within 30 days.)

d. 51ºC and above ambient indicates an emergency situation and corrective action should be scheduled immediately.

Additional Recommended Tests

- ☐ Ultrasonic Noise
- ☐ Vibration Analysis
- ☐ Sweep Frequency Responsible Analysis (SFRA)
- ☐ Furan Test

Results should be reviewed against transformer baseline or results obtained during the EPRI-Solution assessment.

NOTE

1. If the bushings or terminals show visual signs of overheating, bushing gaskets and o-rings must be inspected and replaced if damaged. Power factor of the bushings should also be measured.
2. If the results of the checklist are acceptable (within the manufacturer's specified limits, test equipment vendor's specified limits, or Entergy's specified limits) the transformer may remain in service.

CAUTION

Before any electrical tests are performed, a Total Combustible Gas (TCG) test or Dissolved Gas in Oil Field Test shall be performed for all gas-blanketed transformers. If the total combustible gas is greater than 2%, blanketed transformers shall be purged prior to performing any electrical tests.

If questionable results are obtained from the preceding inspections or tests, the following Out-Of-Service (OOS) tests shall be performed.

- ☐ Megger (500 volts or less)
- ☐ Transformer Turns Ratio (TTR)
- ☐ Insulation Power Factor
- ☐ Winding Resistance
- ☐ Oil Dielectric Breakdown - test per ASTM D877 and ASTM D1816. See Attachment 6.7, Table 1 for limits.

If the results of any of these tests are not satisfactory, then perform Attachment 6.1, "Internal Inspection."

ATTACHMENT 6.6 **CHECKLIST – ELECT. AND MECH. PROBLEMS INCLUDING SUDDEN SIGNIFICANT OIL LEAKS**

Sheet 1 of 2

Transformer Description: **Unit #**

Date: **Inspected By:**

NOTE

1. Refer to Attachment 6.7, "Insulating Oil Acceptance And Maintenance Practices" for interpretation of oil dielectric test results.
2. Refer to Attachment 6.8, "Guide For Interpretation Of Gases Generated In Transformers" for interpretation of DGA test results.

The following in-service inspections and tests shall be performed.

- ☐ Perform Dissolved Gas Analysis (DGA) to determine percent total of combustible gas.
- ☐ Check for unusual odor and color of the insulating oil.
- ☐ Perform Moisture in Oil Test. See Attachment 6.7, Table 1 for limits.
- ☐ Record present and highest reading of the top oil and winding hot spot temperature gauges.
- ☐ Check for temperature differential between the main tank and the Load Tap Changer.

Additional Recommended Tests

- ☐ Ultrasonic Noise
- ☐ Vibration Analysis
- ☐ Sweep Frequency Response Analysis (SFRA)
- ☐ Furan Test

Results should be reviewed against transformer baseline or results obtained during the EPRI-Solution assessment.

NOTE

If the results of the checklist are acceptable, (within the manufacturer's specified limits, test equipment vendor's specified limits, or Entergy's specified limits) the transformer may remain in service.

CAUTION

Before any electrical tests are performed, a Total Combustible Gas (TCG) test or Dissolved Gas in Oil Field Test shall be performed for all gas-blanketed transformers. If the total combustible gas is greater than 2%, blanketed transformers shall be purged prior to performing any electrical tests.

If questionable results are obtained from the preceding inspections or tests, the following Out-of-Service (OOS) tests shall be performed.

- ☐ Megger (500 volts or less)
- ☐ Transformer Turns Ratio (TTR)
- ☐ Insulation Power Factor
- ☐ Winding Resistance
- ☐ Oil Dielectric Breakdown - test per ASTM D877 and ASTM D1816. See Attachment 6.7, Table 1 for limits.

If the results of any of these tests are not satisfactory, then perform Attachment 6.1, "Internal Inspection."

1.0 Oil Handling

> **CAUTION**
>
> Static charges can develop when insulating oil is pumped through pipes, hoses, and tanks. This charge may discharge in the space above the oil and could result in an explosion. Therefore, the processing unit and the equipment being filled including all hoses shall be properly grounded during processing and for at least one hour.

a. All equipment used to process and pump new or acceptable oil shall be inspected, cleaned, dried, and flushed with clean, dry oil to remove any contaminants prior to being used. All hoses used for new or acceptable oil and those used for dirty oil shall be clearly marked as such and sealed on each end when not in use. Prior to filling any reactive equipment (transformers, regulators, or reactors), all oil hoses shall be pre-filled and bled to remove any trapped air, which may be introduced into the equipment.

b. Topping-up shall only be performed via filtering equipment using new or acceptable oil, which has been tested and approved for use. Under no circumstances shall the properties of the oil being added, be worse than those of the in-tank oil. Also do not mix EHV and HV equipment oils.

c. New or acceptable oil shall be transported in containers that are dedicated for transporting new or acceptable oil; not PCB contaminated oil, dirty oil, or scrap oil. Subsequent to each complete emptying, all compartments, pipes, valves, etc., of vehicles used to transport new or acceptable oils shall be cleaned, dried, and flushed with clean, dry oil to remove any moisture or other contaminants.

d. When new or acceptable oil cannot be vacuum processed and pumped from an on-site delivery vehicle directly into the equipment, then temporary storage tanks and absorbent booms shall be used. The preferred vessel is a sealed metal tank. Drums used for storage or transport shall be kept under cover and clearly marked to indicate whether they contain new/acceptable, dirty, scrap, or PCB oil. All new/acceptable oil, which has been stored in temporary or permanent storage tanks, shall be thoroughly inspected/retested as indicated in Table 1 below, prior to being used in any equipment

Table 1

ASTM Test	Test Name	Limit (below 69kV)	Limit (69kv to 115kV)	Limit (115kV and above)
D877	Dielectric, kV	26 min	27 min	28 min
D3612	Dissolved Gases in Oil	*	*	*
D1533b	Moisture Content, ppm	35 max	25 max	25 max to <230 kV 20 max 230 kV and >
D924	Power Factor, 25°C, %	0.5 max	0.5 max	0.5 max
D971	IFT, dynes/cm	25 min	30 min	30 min to <230 kV, 32 min 230 kV and >
D974	Acid Number, mg KOH/g	0.2 max	0.15 max	0.15 max to<230 kV 0.10 max 230 kV and >
D1500	Color, (0.5 - 8.0)	3.5 max	3.5 max	3.5 max
D1816	Dielectric, kV	23 min	28 min	28 min to <230 kV, 30 min 230 kV and >
D2668	DBPC Inhibitor, % by wt	0.09 min	0.09 min	0.09 min

*See IEEE C57.104 "IEEE Guide for the Interpretation of Gases Generated in Transformers"

1.1 Oil Tests and Their Significance

> **NOTE**
>
> Generally, Laboratory Analysis performs Oil Acceptance tests.

a. General

The reliable performance of mineral oil in an insulating system depends on certain basic oil characteristics, which can affect the overall performance of the electrical equipment. In order to accomplish its multiple role of arc-quencher, dielectric, and heat-transfer agent, the oil must possess and maintain certain properties. Namely, it must possess a high dielectric strength, low viscosity, high flash point, low pour point, and high oxidation resistance. The following tests are performed in order to determine whether the oil condition is adequate for continued operation and determining the corrective action required if the oil is unfit for continued use.

b. Gas in Oil Test (D612)

The total gas content normally has little significance in determining the quality or serviceability of the oil. However, some manufacturers of EHV equipment specify maximum total gas content for both new and in-service oils within their equipment.

c. Dielectric Breakdown Voltage Tests (D877 and D1816)

Breakdown voltage tests measure the suitability of an oil to withstand electrical stress. Clean, dry oil exhibits an inherently high breakdown voltage. However, the presence of contaminating agents such as water, carbon, dirt, and/or other electrically conductive contaminants in the oil tend to reduce the breakdown voltage dramatically. But, high dielectric strength does not necessarily indicate that these contaminants are absent from the oil. The D877 test specifies a test cup equipped with one-inch diameter vertical disc electrodes spaced 0.1 inch apart. D877 is primarily used in the field since it is not as sensitive to moisture (atmospheric humidity) as the D1816 test. The D1816 test specifies a test cup with spherical electrodes spaced 0.04 inches apart. D1816 is more sensitive to small levels of contaminants (including moisture) and is primarily suitable for use in the laboratory.

d. Color Test (D1500)

The color test compares the oil color with a standard color index of 0.5 (best oils) to 8.0 (worst oils). A change in the color of in-service oil over time indicates contamination and/or deterioration. Many utilities perform this test in the field using the Hellige Hand-Color Comparator. Any oils with color numbers above 4.0 should be retested in the lab for verification to determine whether or not the oil requires reconditioning or reclamation.

e. Liquid Insulation Power Factor Test (D924)

The power factor of oil is the cosine of the phase angle between an A.C. voltage applied to the oil and the resulting current. The test indicates the presence of contaminants and/or deterioration products such as oxidation products, metal soaps, charged particles, or water. Most in-service oils have a power factor at 25°C of less than 0.2% at 25°C. High levels of power factor greater than 0.5% at 25°C are of concern because contaminants tend to be drawn into areas of high electrical stress within the equipment, which may further complicate matters. Very high levels (greater than 1.0% at 25°C) may be caused by the presence of free water and could be hazardous to the operation of the equipment.

NOTE

Transformers, which are suspected to be wet, should be tested for water content at cold temperatures such as during winter outages. To determine the amount of free water, which forms when a transformer is cooled, the amount of water in the oil at the highest operating temperature, the solubility of water in oil at the lowest operating temperature, and the number of gallons of oil in the transformer must be used in the above equations

f. Moisture Test (D1533B)

Water can be present within electrical equipment as a gas (dissolved state), as a liquid (free-state), as tiny droplets mixed within the oil (emulsified state), or as a solid (frozen state). Once present, the water will change states based on the water concentration, temperature, and pressure within the equipment. In transformers, the majority of any water present will reside in the cellulose insulation. As the temperature increases, a fraction of the water in the paper is driven into the oil. The presence of free or emulsified water may be visually observed as separated droplets or in the form of a cloud dispersed throughout the oil. This emulsified or free water can dramatically reduce the dielectric strength of both the oil and the cellulose insulation depending on the temperature. Yet water dissolved in the oil has a much lesser effect on the dielectric strength.

The presence of water also acts as a catalyst to corrosion and oxidation processes, which shortens the life of the equipment, the oil, and the cellulose insulation. However, the D1533B moisture in oil test alone is not sufficient. See the example below for details.

Example: If a transformer is operating at 80°C with 3% water in the cellulose by weight, then the water in oil will be approximately 85 ppm. If the transformer temperature is quickly cooled to 10°C as could be expected when it is removed from service during the winter, the cellulose would not adsorb the water in oil very quickly and much of the water would remain in the oil. Using equations 1 and 3 below for 10°C (283°K), the oil can hold only approximately 36 ppm of water (S) at 10°C. Therefore, the transformer will be 85 minus 36 = 49 ppm above the saturation level. Using equation 4 below, for every 1000 gallons of oil, there would be 3.33 times 49 = 163.17 milliliters of free water.

Equation 1: $\log S = (-1567 / °K) + 7.0895$
Equation 2: $°F = (9/5)\ °C + 32$
Equation 3: $°K = °C + 273$
Equation 4: Free Water, ml H_2O/1000 gal oil = 3.33 * (ppm of water above saturation) where S is the solubility of water in oil and K, F, and C are the oil temperatures in Kelvin, Fahrenheit, and Celsius, respectively.

g. Interfacial Tension Test (D971)

The interfacial tension (IFT) of oil is the force required to rupture a film of the oil at an oil-water interface. The test indicates the presence of soluble polar contaminants and/or degradation products such as paints, soaps, varnishes, and oxidation products, which weaken the film strength of the oil and hence decrease the IFT. IFT is a key indicator in determining when oil requires reclamation.

h. Acidity Test (D974)

The acid number (neutralization number) of oil is a measurement of the amount of acidic or basic materials present in oil. As in-service oils age, the acidity and hence the acid number increases due to oxidation products. When the oxidation process is allowed to continue without correction, acids, metallic soaps, and sludge are formed that interfere with the oils' ability to transfer heat and affect transformer cooling. Acidity is also a key indicator in determining when oil requires reclamation.

i. Oxidation Inhibitor Test (D2668)

This test measures the amount of DBPC inhibitor present in the oil. Because inhibitors slow down the formation of acids and sludge, it is very important that approximately 0.3% DBPC content be maintained to help maximize the service life of the oil and equipment.

1.2 Testing and Maintaining In-Service Transformer and Voltage Regulator Oils

In order to help prevent failures due to the contamination and/or deterioration of in-service insulating oils or incipient internal faults, the tests listed in Table 2 above shall be performed on the insulating oils of all stations transformers and three phase regulators using the following limits at recommended intervals.

NOTES:

1. Oils that do not meet the specified limits in their respective voltage classes may be considered for reuse in similar equipment operating at a lower voltage class, if they meet the limits for that class, or they may be suitable for reconditioning or reclamation.
2. Oils should not be removed from service when a single test limit is exceeded, nor should they remain in service until all test limits are exceeded. See Section 1.3 "Guidelines When Test Limits in Table 1 have been exceeded" for details.
3. Approved site container should be used for collecting samples for the above tests with the exception of D3612, D1533b, and D877. One 50cc glass syringe shall be used for collecting samples for D3612 dissolved gases in oil and D1533b moisture in oil tests.
4. The D877 dielectric test shall be performed at RCM intervals. All other tests in Table 2 shall be performed in the laboratory using the specified interval.

1.3 Guidelines When Test Limits in Table 1 have been exceeded

Table 2 shall be used as a guideline for determining the action required when specific test limits are exceeded.

TABLE 2

ASTM Test	Below 69kV	69kV to 115kV	115kV and above	Test Grade *	Action Required**
D877 Dielectric (0.1" gap) kV	> 27 26 – 27 < 26	> 28 27 – 28 < 27	> 29 28 – 29 < 28	A Q U	1 2 3
D1533b Moisture ppm	< 30 30 - 35 > 35	< 20 20 - 25 > 25	<20 (below 230 kV)< <15 (230 kV up) 20-25 (below 230 kV) 15 – 20 (230 kV up) > 25 (below 230 kV) >20 (230 kV up)	A A Q Q U U	6 6 6 6 6 6
D924 Power Factor 25ºC, %	< 0.3 0.3 – 0.5 > 0.5	< 0.3 0.3 – 0.5 > 0.5	< 0.3 0.3 – 0.5 > 0.5	A Q U	1 2 3
D971 IFT Dynes/cm	> 27 26 – 24 < 25	> 32 29 – 27 < 30	> 32 (below 230 kV) > 34 (230 kV up) 32 – 30(below 230 kV) 34 – 32 (230 kV up) < 30(below 230 kV) < 32 (230 kV up)	A A Q Q U U	1 1 2 2 4 4
D974 Acid # mgKOH/g	< 0.15 0.15 – 0.2 > 0.2	< 0.1 0.1 – 0.15 > 0.15	<0.1 (below 230 kV) < 0.05 (230 kV up) 0.1 – 0.15 (below 230 kV) 0.05 – 0.1 (230 kV up) >0.15 (below 230 kV) > 0.1 (230 kV up)	A A Q Q U U	1 1 2 2 4 4
D1500 Color	<3.5 > or = 3.5	<3.5 > or = 3.5	<3.5 > or = 3.5	A U	1 3
D1816 Dielectric 0.04" gap, kV	> 25 23 – 25 < 23	> 30 28 – 30 < 28	> 30 (below 230 kV) >32 (230 kV up) 28 – 30 (below 230 kV) 30 -32 (230 kV up) < 28 (below 230 kV) <30 (230 kV up)	A A Q Q U U	1 1 2 2 3 3
D2668 DBPC %	> 0.2 0.2 – 0.09 < 0.09	> 0.2 0.2 – 0.09 < 0.09	> 0.2 0.2 – 0.09 < 0.09	A Q U	1 2 5

Table 2 (continued)

* Test Grade: A - Acceptable Q - Questionable U - Unacceptable

** Action Required:

1. No action required.
2. Resample and verify test(s) in question. Reduce interval for the test(s) in question.
3. Resample and verify test(s) in question. Oil requires reconditioning.
4. Resample and verify test(s) in question. Oil requires reclamation or replacement.
5. Resample and verify test(s) in question. Add DBPC to oil to attain 0.3% by weight.
6. Test is temperature dependent. See Section 1.1 (f) "Moisture Test" for details.

Attachment 6.7 Insulating Oil Acceptance and Maintenance Practices
Sheet 8 of 13

1.4 Oil Specifications and Acceptance

Prior to filling any electrical equipment with oil, the specifications listed below for the D1533b Karl Fisher moisture test and the D877 dielectric test must be met. These tests may be performed in the field. A laboratory must accomplish all other tests.

Table 3

ASTM Method	Test Name and Description	Measurement Parameter	Type II Oil Test Limit
D92	Flash Point	°C	145 min
D97	Pour Point	°C	-40 max
D445, D2161	Kinematic Viscosity, 40 °C	cSt	11.0 max
D877	Dielectric Breakdown (0.1" gap)	kV	30 min
D924	Power Factor, 60 Hz, 25 °C	%	0.05 max
D971	Interfacial Tension (IFT), 25ºC	dynes/cm	40 min
D974	Neutralization Number (modified)	mg KOHI	0.015 max
D1298	Specific Gravity 60/60 °F	NIA	0.865-0.910
D1500	Color 0.5 (new oil) - 8.0 worst	NIA	0.5 max
D1533b	Moisture Content (as received)	ppm	25 max
D1816	Dielectric Breakdown (0.04" gap)	kV	20 min
D2668	Oxidation Inhibitor content	% by wt	>0.08 - 0.3
D4059	PCB Content	ppm	None detected
D1524	Visual Examination	-	Bright and Clear
D1275	Corrosive Sulfur	-	Not Corrosive

a. Drum Oil

Examine each drum, especially the screw bung, for damage or leaks immediately after unloading. Drums shall be stored either on their sides or upside down or under protective cover to prevent moisture contamination. If a shipment of drums contains oil from the same manufactured lot, their contents may be combined into one clean, dry storage tank, sampled, and tested to ensure that the oil meets the limits specified in Table 3 prior to being used. If this is not possible, or several drums from different lots have been purchased, a D-877 dielectric test and a D1533b moisture test shall be performed, as a minimum, on samples from every drum using the limits established in Table 3 for those particular tests.

1.5 Handling of Oils Which Have A High Combustible Gas Content

This guideline applies to the maintenance of oil-filled power transformers, autotransformers, and voltage regulators. The specific application is intended for equipment that may have been subjected to internal or external fault conditions, which can cause a high level of combustible gases to exist within the main tank.

a. Safety

This guideline does not address all possible safety issues associated with maintenance or testing of the equipment involved. The user should consult the POC or the System Engineer for the specific equipment manufacturers' instruction manuals, Entergy's Operations Industrial Safety Rulebook and federal, state and local regulations for detailed instructions and guidelines.

b. Details

Oil-filled equipment, which has been subjected to fault conditions (either internal or external), has a potential to contain flammable or explosive gases generated by the chemical breakdown of oil caused by the energy of the fault. Special procedures are required to prevent possible ignition of these gases, if present, which may pose a hazard to personnel and equipment.

c. Flammability of Gases

NOTE

Flammable limits are at 1 atmosphere and 25 degrees C (77 deg. F).

The following table indicates the concentration limits over which combustible gases will form explosive mixtures with air.

Gas	Flammable Limits in Air				
Acetylene	2.5 - 100%	or	25,000	to	1,000,000 ppm
Ethylene	2.7 - 36%	or	27,000	to	360,000 ppm
Ethane	3.0 - 12.4%	or	30,000	to	124,000 ppm
Methane	5.0 - 15.0%	or	50,000	to	150,000 ppm
Hydrogen	4.0 - 7.5%	or	40,000	to	75,000 ppm
Carbon Monoxide	12.4 - 74%	or	124,000	to	740,000 ppm

d. Determining Gas Concentrations

The amount of combustible gas in the gas space can be determined in two ways. The first is by a direct measurement on the gas phase using a portable combustible gas meter. The measured quantity is called the total combustible gas (TCG) reading. The second way to determine the concentration of gas is by means of a chemical analysis for dissolved gases in the oil. From the dissolved gas analysis (DGA), the corresponding concentration of combustible gas in the gas space is calculated. This calculated quantity is the equivalent total combustible gas (ETCG) value. The ETCG value is included on the DGA report received from the test laboratory.

e. Criteria for Handling Oil

The ETCG value is used as the basis for determining how oil is to be handled. ETCG values above 2% are considered high and any level above this requires that the oil be handled with caution following the procedures described in this guideline.

f. Electrical Testing

For equipment that has been opened or otherwise exposed to air or oxygen, no electrical tests should be performed until it has been determined that the ETCG value is below 2.0%. This is to prevent the possibility of ignition of flammable gases due to an electrical spark or heating effects. For sealed equipment, which is nitrogen-blanketed, testing should pose no problem. Ignition requires the presence of oxygen, which would not normally be present in a sealed unit following a fault. The tester should verify that the unit has remained sealed prior to performing any electrical testing without an oil test. If there are questions regarding safety of performing electrical tests on faulted equipment, O&M Services should be contacted for specific recommendations.

g. Methods to Lower Gas Concentrations

The following methods to lower ETCG require that the equipment be out of service.

- **Direct Percolation**

  The preferred method for removing the high concentrations of combustible gases from the oil is to percolate nitrogen through the oil while venting the equipment to the atmosphere. This "out-of-service" (OOS) process can take considerable time. The time will depend on the concentration and types of gases, which are dissolved in the oil. Also, the temperature and volume of the oil will affect the time required. During the process, it is recommended that the gas space be monitored using a portable TCG meter to verify gas levels.

CAUTION

When the Draining and Percolation method is used, the oil must be removed and the unit vacuum-filled. This is necessary because of bubbles, which may be trapped in the oil and may cause problems when the unit is energized.

- **Draining and Percolation**

  The method recommended for load tap changers is as follows: Gravity feed the oil into drums while the compartment is vented to the atmosphere. Percolate nitrogen into the drain valve after the oil is removed to purge any residual gases which may be contained within the compartment. Then the barrels must be percolated with nitrogen from the bottom of the drum by means of tygon tubing. Once the drums have been purged, another Dissolved Gas in Oil test must be conducted for disposal purposes and the ETCG confirmed to be below 2%.

NOTE

Oil must be replaced only when the oil qualities fail to meet Entergy specifications.

- **Bonding and Grounding**

  Prior to any transfer of oil from the equipment, it will be necessary to verify proper bonding and grounding of any equipment associated with the transfer. Use of bonded hoses with proper grounds will insure an equal potential between the elevated oil-filled equipment and the oil handling equipment, thereby minimizing the possibility of a static discharge. Proper handling requires the use of bonded hoses with approved fittings that ensure continuity of conductivity. In addition to the oil-handling hoses, all equipment associated with the oil transfer must be grounded to the substation ground grid. It is important to note that a continuity check must be conducted on hoses prior to their use.

- **Oil Reclamation**

  For large quantities of insulating oil in transformers, regulators and reactors, the method of direct percolation is preferred (if the intent is to reclaim or replace the insulating oil). If the oil is to be reclaimed by utilizing oil degasification equipment, then it must meet Entergy insulating oil specifications for the particular class of equipment.

- **Oil Disposal**

  Prior to disposal of any equipment insulating oil, the equivalent total combustible gas level (ETCG) must be lowered to less than 2%. Any disposal must be carried out according to applicable environmental regulations.

> **CAUTION**
>
> 1. Prior to transferring insulating oil from equipment (by any method other than gravity flow), it is necessary to perform a Dissolved Gas in Oil Analysis. DGA test results must indicate the equivalent total combustible gas level (ETCG) is below 2.0% if the oil is to be handled without prior treatment. The purpose of the DGA test is to provide a basis to determine if special oil handling procedures are required.
> 2. If the total combustible gas level is above 2.0%, extreme caution must be observed in handling the insulating oil, and the oil must be processed to lower the combustible gas concentrations before any oil is transferred (except in the Load Tap Changer (LTC) by gravity flow method).

The equipment must be vented while the oil is being transferred. Also, the storage container (tanker, drum) must be properly vented to the atmosphere during the filling and storage process.

Precautionary measures must be taken during the processing of oil containing high levels of combustible gas (2.0% or more). These precautions include posting "No Smoking" signs and barricading the area to warn personnel of the potential danger.

During the oil filtration process, the gases will be liberated from the oil due to aeration of the oil passing through the pump, filter, and hoses. Therefore, it is imperative that the oil transfer containers be properly vented during the process to allow the combustible gases to escape into the atmosphere.

> **NOTE**
>
> Avoid using centrifugal pumps that by design agitate the oil and can potentially cause static electrification.

Ignition can be derived from mechanical, thermal or electrical sources. Avoid all potential sources of static discharge by grounding and bonding the equipment. This will maintain equal potentials between the associated equipment.

Time is required for the gas and oil phases to reach equilibrium when combustible gases are generated. Depending on the time lapsed between the fault and the initial oil test a follow-up test may be required. In general, 24 hours is sufficient time for equilibrium to be reached.

Analysis:

Dissolved Gas Analysis, while complex in practice, is based on some fairly simple principles.

Insulating oil will tend to break down or degenerate when used as a dielectric medium in a power transformer over time. This process and its manifestation are affected by time, heat, and electrical stresses. As the oil degrades, its constituent parts are broken down and the resulting chemical reactions produce certain gases, which are present in the oil as dissolved agents. The operating mode of the unit will determine which gases are present, and their relative distributions. By knowing the content of dissolved gases in insulating oil, we can determine to some extent the stresses to which the equipment has been subjected.

Oil is composed of hydrocarbons, and the degeneration process is predictable under controlled conditions. There are two distinct modes under which specific gases will be produced - thermal and electrical. The gases produced are determined by the amount of energy dissipated in an event. The sequence of gas generation is predictable based on the energy level. The main gases of interest are Hydrogen, Methane, Ethane, Ethylene, Acetylene, Carbon Monoxide, and Carbon Dioxide. With the exception of Carbon Dioxide, all these gases require energy dissipation to produce in an oil-filled environment. Carbon Dioxide is a naturally occurring gas, which is produced spontaneously over time.

The first gas to be produced is Hydrogen, which requires a very small amount of energy for extraction, and only requires corona activity to produce. The most difficult gas to produce is Acetylene, which requires the greatest amount of energy. Both of these are produced due to electrical effects, differing only by degree. Acetylene typically requires an electrical arc under oil, which will produce extremely high local temperatures. Hydrogen can also be produced by elevated heat (i.e., hotspot).

The remaining gases are all related to thermal effects, which may be produced through various mechanisms. A mild overloading condition can produce quantities of Methane, which requires relatively low temperatures, while Ethylene will require significantly elevated temperatures to form. Ethane falls in the middle. These three gases are the primary indicators of chemical changes caused by heat. The relative proportions of the gases give an indication of the severity and / or duration of the event or events.

Carbon Monoxide (CO) is an indicator of the breakdown of cellulose within the transformer insulation system. This may be the insulating paper, spacers, or any oil-saturated cellulose structure. Because relatively low temperatures are required for the decomposition of cellulose compared to oil, the CO is typically accompanied by a small amount of Methane, the indicator of low-level heating effects on oil. Since there is always some Carbon Dioxide present, and this gas is not significantly affected by either electrical or thermal events on the same scale as oil, the ratio of Carbon Dioxide to Carbon Monoxide is generally used as an indicator of the relative level of cellulose degradation.

An important note to consider is the fact that once a gas is produced, it will remain dissolved in the oil indefinitely so that each transformer will have a characteristic "signature" or background level, which is the history of events to which the oil/paper system has been subjected. This signature will be unique for each unit, and must be taken into account when performing a dissolved gas analysis. For this reason, there are no "absolute" levels which can be determined as acceptable or unacceptable limits without regard to prior operating history. Even processing the oil or completely changing the oil in a transformer will not completely "erase" this background level. H_2 levels may decrease slowly over time due to the gas escaping through packing due to the small size of the molecule.

It is impossible to remove all the oil from a transformer since there is always a certain amount which is held by the saturated paper insulation and blocking. The dissolved gases in the trapped oil will leach back into the tank oil when a unit is processed or refilled, and the gases will redistribute throughout the unit. The effect will be less pronounced, but still present.

An analysis of the gases present is possible. The most typical example is using Gas Chromatography, a laboratory procedure where gases are extracted from an oil sample under a high vacuum and analyzed. Other methods use test equipment which is based on photo-acoustic spectroscopy. It is important to remember that the gases of interest are those which are dissolved in the oil. Those contained in the gas space do not enter into this analysis although they may also be used as an indicator of a different sort.

If gases are produced at a fairly constant rate, they can be absorbed by the oil until it reaches a saturation level. This level is extremely high for the gases involved. In the case of Acetylene, the saturation level is 400%. These saturation levels vary by gas type. In other words, the oil can support four times its own volume in dissolved Acetylene before the gas will begin to collect as a free gas in the blanket space. However, if the thermal or electrical event is localized, it is possible to produce pockets of oil, which is supersaturated, causing the local evolution of free gas at levels below the overall tank oil saturation level. This produces bubble formation. If the level of generation is high enough, or the reaction is violent enough, large bubbles can be formed which can cause the dielectric to be effectively breached, causing failure. The generation rates are typically very low, and normally there is a small quantity of the gases of interest present in the gas space. This gas can be tested using a portable instrument, which reads the TCG or Total Combustible Gas level. This TCG level is closely associated with the gas generation rate, which is an indication of how rapidly the gases are being produced within the transformer. An advantage of this method is that it is field-measurable and gives an almost instantaneous readout. This information is most valuable when examined in conjunction with the DGA results. Although in the past, it has been used as a primary indicator in determining the condition of a transformer after the unit has been subjected to a fault in determining whether or not to return the unit to service.

General:

Sampling the oil in the main tank of the transformer allows a general view of the overall condition of the unit. Although it is very seldom that one of the following conditions exists in isolation, the basic nature of a problem can usually be diagnosed with reasonable certainty. Quantities of the gases indicated (in a dissolved state) in the transformer oil give indications of the conditions outlined.

Hydrogen

Corona is normally the mechanism by which this gas is generated. Sources of corona can be sharp metallic edges, exposed wiring or any point where there is a high electric field. Very seldom is a high level of hydrogen generated by itself. Normally, it will be accompanied by either elevated levels of acetylene or the "heating" gases (ethylene, ethane and methane). "Normal" levels of hydrogen in a transformer which has been in service for some time are in the range of 200-500 parts per million. Values significantly exceeding this range are indication of a problem. H_2 can also be generated at temps >250^C from thermal and electrical faults.

Acetylene

An electrical arc under oil is the mechanism, which produces acetylene. A high level of acetylene is almost always accompanied by an elevated hydrogen reading. A turn-to-turn fault or a foreign object bridging two energized conductors or a loose/broken connector can produce the arc. "Normal" levels for acetylene are much lower than other key gases. Ideally, the acetylene level should be zero; however, values below 15 parts per million are not uncommon in transformers which have been in service for some time. Values above 15 ppm are cause for concern. Any detectible value should be promptly resampled unless previously identified and actions taken.

Carbon Dioxide and Carbon Monoxide

The ratio of carbon dioxide (CO_2) concentration to carbon monoxide is more important than the individual values for either gas alone. Carbon dioxide is a naturally occurring gas, which is produced spontaneously over time. Carbon dioxide is also generated by thermal decomposition. Carbon monoxide is produced by the thermal breakdown of cellulose. As the insulation system begins to degrade, the ratio of CO_2 to CO gets smaller, as the value of CO begins to increase. Values of this ratio below 10 are indications that there is a problem with the integrity of the insulation system. This analysis is most accurate when the concentration of CO_2 is at least 5000 ppm and CO is at least 500 ppm.

Methane, Ethane and Ethylene

These three gases are produced by the thermal decomposition of mineral oil. Their presence is an indication of significant heating effects. The associated heating can be produced by several different causes, such as overloading, over-excitation, blocked cooling ducts, failed pumps or fans, circulating currents, and many other conditions. Usually, the relative levels of the three gases give a clue as to the heating history (long-term, low energy versus short-term, high energy).

Normal levels for these gases in in-service transformers are: Methane - 50 to 125 ppm, Ethane - 35 to 75 ppm and Ethylene - 80 to 175 ppm. A long-term, low energy condition would tend to have higher levels of Methane, while a short-term high-energy condition will tend to have an elevated level of Ethylene. If all three gases are elevated, this is an indication of a severe overheating condition that requires immediate attention.

It should be remembered that the rate of production of the various gases is also an indication of the condition of the unit. A sudden increase in generation of a gas is cause for concern, while a slow and gradual build-up may simply be due to normal operation. The gas generation rate is calculated based on the differences between two successive readings. If the oil is processed, a higher calculated rate would be expected as the levels were artificially forced to near-zero.

Only in the case of a sudden drastic change in the gas profile should a transformer be taken out of service for an internal inspection. In most cases, if the gas levels suggest a problem, the sampling cycle should be shortened to obtain more data. In many cases, a temporary change in the operating conditions of a transformer can produce transient high levels of specific gases, which require no intervention. Significant levels of acetylene or hydrogen are the exception and do warrant internal inspections. The presence of an arc or high corona activity is the indication of potentially hazardous conditions, which can lead to explosive concentrations of these gases.

Total Combustible Gas (TCG)

The TCG represents the overall concentration of combustible gases and can be used as a general indicator of the state of a transformer. A sample of the insulating oil should be taken regularly (annually unless history or other guidance suggests more frequent sampling is necessary) in order to establish "normal" operating conditions. A guide for acceptable concentrations of dissolved gas in a transformer with no sampling history is available in IEEE C57.104.

Guidelines for Additional Sampling

A transformer should be considered a candidate for additional oil sampling if any of the key gases is above its threshold value outlined in IEEE C57.104 section 4.6. The section titled, "Evaluation of Transformer Condition Using Individual and TDCG Concentrations," should be referenced to determine threshold values. If the DCG concentration of the oil exceeds the levels for Condition 2 as described in IEEE C57.104, another sample should be taken immediately to verify this information. If additional samples verify that DCG levels are rising, additional sampling should be scheduled at least as frequently as recommended by IEEE C57.104. An examination of the subsequent test samples drawn one or two months after the initial sample should determine whether the indication of a problem was due to a transient condition, a bad sample, or represents actual conditions.

NEIL guidelines on transformer conditions should also be adhered to.

Evaluation of Dissolved Gas Content
Dissolved gases shall be trended. When issues are identified, an evaluation of the gases shall be performed using the Doernenburg and Rogers ratios as well as key gas analysis. Any abnormal readings will be discussed on a fleet call. The gas ratios used in these methods are:

Ratios used for Doernenburg Ratio Method:
CH_4/H_2
C_2H_2/C_2H_4
C_2H_2/CH_4
C_2H_6/C_2H_2

Ratios used for Rogers Ratio Method:
CH_4/H_2
C_2H_2/C_2H_4
C_2H_4/C_2H_6

Methods for using these ratios are available in IEEE C57.104 in the section titled, “Evaluation of Possible Fault Type by Analysis of the Separate Combustible Gases Generated.” A brief interpretation of gases is included in Figure 1 of IEEE C57.104.

Guidelines for Removing a Transformer from Service for Inspection

A transformer should only be removed from service when it is indicated that either a failure is imminent or that continuing to operate the transformer in its present condition may cause irreversible damage. This is not a decision to be taken lightly, but when necessary, expediency is highly recommended.

A transformer that is operating under “Condition 3” status, according to IEEE C57.104, should be evaluated under peer review (fleet call). The participants of the call will evaluate the results of the gas concentration tests and determine whether the transformer is fit for service. **Any levels of acetylene are cause for concern and should be immediately resampled and plans to remove the transformer from service will be made with Operations.**

Data:

Laboratory results of the DGA analysis are used by the System Engineer in determining the course of action to be followed regarding the sampled transformer. A guide outlining necessary actions is included in IEEE C57.104, section 4.4.2 titled, “Determining the Operating Procedure and Sampling Interval From the TDCG Levels and Generating Rates in the Oil.”

It is the responsibility of the POC and System Engineer to make an evaluation as to whether the transformer should be removed from service, sampling should be accelerated, or no action at all. It is recognized that this equipment is expensive and impacts plant operation and the final decision to remove a transformer will be made by senior management, with engineering input. The T&D group is available for technical support or to make recommendations based on historical data, but their input should be considered as consultation.

In cases requiring removal of equipment from service for inspection, it is the grid's responsibility to make every effort to arrange for an outage for the necessary work. If an outage cannot be obtained in a reasonable time, the grid representative should document the inability to obtain an outage. A memorandum outlining the request should be sent to the Grid Manager (ISO's or SOC) and also to the Manager-TSS (NSTAR, VELCO, ENTERGY, etc). The memo should state the person requesting the outage, the date the outage was requested, the reason the outage was denied, and the person who refused to grant the outage. This should be done as soon as it becomes known that the equipment cannot be taken out of service.

Contacts:

Site notification requirements and test lead contacts shall be provided by site System Engineer.

It is the responsibility of the System Engineer to maintain a database of historical DGA data for the system. Also, it is the duty of the System Engineer to update the files with current laboratory test results. The System Engineer will review the incoming data to identify potential problems based on historical information, and other available sources, including loading data, Doble testing, acceptance tests, field electrical tests and internal inspections. Where problems are indicated, a list of any problem units, along with a recommended course of action will be discussed with appropriate personnel.

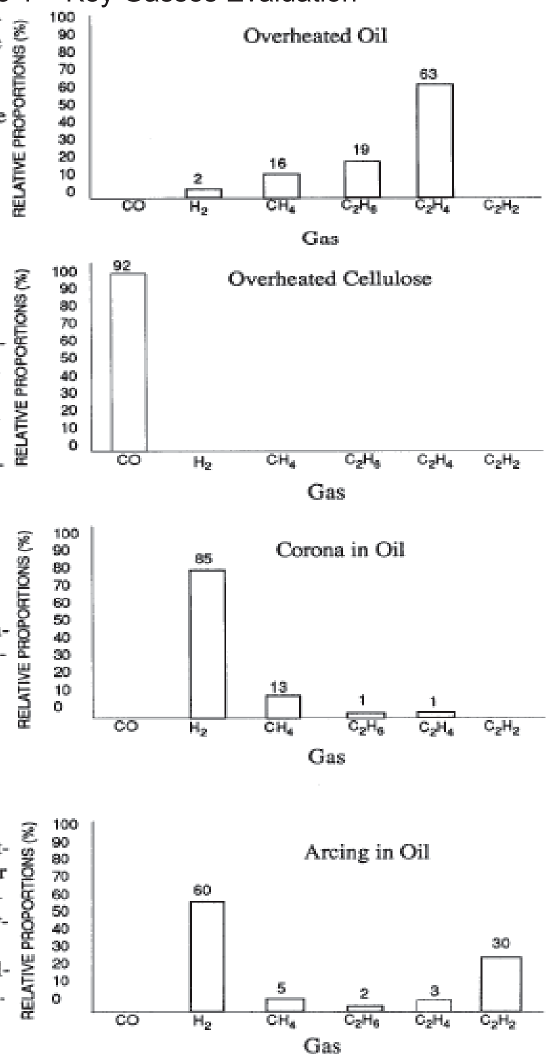
Figure 1 – Key Gasses Evaluation

1. Thermal—Oil: Decomposition products include ethylene and methane, together with smaller quanities of hydrogen and ethane. Traces of acetylene may be formed if the fault is servere or involves electrical contracts.
Principal Gas — Ethylene

2. Thermal—Cellulose: Large quantities of carbon dioxide and carbon monoxide are evolved from overheated cellulose. Hydrocarbon gases, such as methane and ethylene, will be formed if the fault involves an oil-impregnated structure.
Principal Gas — Carbon Monoxide

3. Electrical—Corona: Low-energy electrical discharges produce hydrogen and methane, with small quanities of ethane and ethylene. Comparable amounts of carbon monoxide and dioxide may result from discharges in cellulose.
Principal Gas — Hydrogen

4. Electrical—Arcing: Large amounts of hydrogen and acetylene are produced, with minor quantities of methane and ethylene. Carbon dioxide and carbon monoxide may also be formed if the fault involves cellulose. Oil may be carbonized.
Principal Gas — Acetylene



NOTE

The above figure is from IEEE C57.104

Subject: OE15787 - Incorrect Torque Value Used During the Installation of Main Transformer Bushings

Abstract: On August 8, 2002, during the installation of a new low voltage bushing (24 kV) on the Sequoyah (SQN) Unit 1 Main Bank Transformer C, it was discovered that the incorrect torque value was used to makeup the connection between the bushing and the transformer winding. The SQN Transmission/Power Supply (TPS) Manager questioned the supplied torque requirements and it was determined that the values used were incorrect. This incorrect value was obtained by informal means due to the work process and the requirements lacking the rigor and documentation required by the site's work planning requirements.

Reason for Message: The purpose of this Operating Experience entry is to illustrate the problems encountered when detailed work instructions are not required for switchyard work.

Event Date:	August 26, 2002
Unit Name:	Sequoyah Unit 1
NSSS/A-E:	Westinghouse/TVA
Turbine Manufacturer:	Westinghouse

Maintenance Rule Applicability: None

Component Information (as applicable): Main Transformer Low Voltage Bushings
Manufacturer: ABB **Model Number:** **Part Number:**

Description: In July 2002, TPS working under an inter-group agreement as a site contractor, planned and generated a work document for replacing the low side bushing on 1-C Main Bank Transformer. The work document was prepared according to the requirements of the TPS procedure, "Work Plan Development." After the planning was completed, the work document was provided to the site Electrical Maintenance Planners for review. This review was completed and comments including the absence of any internal torquing requirements were provided to TPS for resolution. The inter-group agreement between TPS and TVA Nuclear specifies that the boundary for systems that are under the plant work processes control is at the connection to the low voltage bushing on the main bank transformer. Work past this connection point to the switchyard falls under the TPS Standard Programs and Processes (SPP) work control. The TPS SPP procedures for developing work instructions on transmission system equipment, does not require work past the boundary to be performed according to detailed written instructions. Under this process, TPS work instructions typically contain detailed steps on removing and returning transmission system equipment to service, and rely on vendor instructions and skill of the craft for performing maintenance or modifications on the equipment. This procedure does not contain any guidance on the level of detail for planning work instructions or the changes, review and approval of vendor manuals or vendor installation instructions. In August 2002, TPS personnel reviewed the new bushing and related drawings against the existing configuration, but did not analyze the differences (including torque values). During the installation process the torque value included in the vendor installation instructions was questioned by the TPS site manager. The TPS engineer then requested clarification of the torquing requirements from the vendor which verbally advised to use 100 ft-lbs.

Causes: The root cause of this event was inadequate written communication. TPS procedures do not contain sufficient guidance on the level of detail for planning work instructions, or the process for change, review, and approval of vendor manuals or vendor installation instructions. The vendor manuals for the equipment lack up-to-date drawings or accurate Bill of Materials. TPS personnel rely on vendor instructions and skill of the craft for performing maintenance or modifications on switchyard equipment.

Corrective Actions: Procedures will be developed and/or revised to provide more guidance for configuration control, vendor manual changes, and work instruction preparation for work outside the plant systems boundary and under control of TPS.

Safety Significance: There is no nuclear safety significance because analysis determined that either the 55 ft lbs or 100 ft lbs were adequate.

Subject: OE16057 - Automatic Plant Trip Due to Moisture in Main Transformer Electrical Connector

Abstract: With Watts Bar 1 at 100 % power, a Generator Backup Relay unexpectedly actuated causing an automatic turbine/reactor trip. The relay actuated due to a ground fault caused by moisture intrusion into the C phase main transformer's high side bushing capacitance tap connector. The root cause of this event was inadequate preventive maintenance, which was not identified as the cause of a similar event in 1997 (ref. INPO Plant Event Rpt 390-970420-1 or LER 390-97010). Corrective actions include repairing the connector, revising preventative maintenance (PM) procedures, and a design change to the affected relay scheme.

Reason for Message: To share lessons learned regarding the proper maintenance for a switchyard connector that may be commonly used in switchyards, and the relaying/metering design change. Stations should review their PM procedures to determine if similar weaknesses exist.

Event Date:	3/10/03
Unit Name:	Watts Bar Unit 1
NSS/A-E:	Westinghouse/TVA
Turbine:	Westinghouse

Maintenance Rule Applicability: Yes

Component Information: The failed connector is an integral part of the "Connecting Cable for GE Potential Device to the Transformer Capacitance Tap" - Part No. 4B628G03

Description: At 0012 on 3/10/03, the Main Generator Breaker opened unexpectedly, which initiated an automatic turbine/reactor trip. Plant equipment functioned as designed in response to the trip. Control room indication showed the event was initiated by generator backup relay 121 GB, an impedance type relay that uses both current and voltage potential to detect faults. This relay is connected to a current transformer (CT) and a potential transformer (PT) on the high side bushing of each 500 kV main transformer (3 - one per phase), and provides backup protection for the generator and the transformers.

Megger testing showed C phase of the PT was shorted to ground. Further troubleshooting found evidence of arcing on the C phase main transformer's high side bushing capacitance tap connector, damage to its o-ring seal, cracks in the external RTV sealant, and blackening of the petrolatum insulating grease inside the bushing well, all of which indicated this was the faulted component. This was confirmed following an evaluation of the operational characteristics of the 121 GB relay and other generator protective relays. The A phase potential connection was also found to have a damaged o-ring. An analysis is being performed on the o-rings to substantiate the failure mechanism.

Causes: The root cause of this event was inadequate preventive maintenance because of the failure to incorporate vendor recommendations into the applicable PM procedure, which was also not identified as the cause of the similar 1997 event.

The PM procedure was inadequate in that it specified the use of an inappropriate insulating compound (petrolatum), and contained improper guidance for filling the connector with this compound and for tightening the connector cap. Over filling and over tightening these connectors may damage the O-ring, increasing the potential for the petrolatum to leak out and moisture to enter the connector. The vendor recommended insulating compound is heavy insulating oil. Following this event, it was learned that petrolatum becomes fluid above 54ºC (129.2ºF) and can absorb moisture. The use of RTV sealant, although not required per the PM, was an additional barrier incorporated from the 1997 event.

Corrective Actions: The immediate corrective actions included repairing the connector (cleaning; o-ring replacement; filling with the proper insulating compound), replacing damaged cables, and changing the position of an existing transfer switch to make the 121 GB relay voltage potential source a switchyard bus section versus the main transformer high side bushings. The latter action removed these potential device connectors from any protective relaying function.

Additional actions include: Personnel were briefed on the importance of identifying the cause of an equipment failure versus just treating the symptom(s) to prevent an event from recurring.

Revising applicable PM procedures to incorporate vendor recommendations for maintaining an one-quarter inch expansion space when filling the tap well with either GE Al 3A1 B heavy oil or GE Al 3A3A1 transformer insulating oil, and to tighten the cap only snug tight.

Adding GE Instruction (GEI) 79087D to the applicable vendor manual and appropriately revising the affected Transmission Power System field test manual.

A design change will be made to improve the reliability of Generator Backup relay 121 GB by installing redundant trip logic (e.g., 2/2 or 2/3), or a loss of relay function to detect a blown fuse or loss of potential to block the possible incorrect tripping of the protective relays.

Subject: OE16334 - Main Generator lock-out scram

Abstract: On 6/01/03 at 08:50 EST Pilgrim Station scrammed from 98.5% power due to a Main Generator lock-out relay actuation.

Reason for Message: This is a preliminary notification to inform the industry of the event and probable cause. A follow up will be issued upon completion of the root cause.

Event Date:	6/01/03
Unit Name:	Pilgrim
NSSS/A-E:	G.E./Bechtel
Turbine Manufacturer:	G.E.

Maintenance Rule Applicability: Yes, caused Unit shutdown

Component Information (as applicable):

Description: On 6/01/03 at 08:50 EST Pilgrim Station scrammed from 98.5% power due to a Main Generator lock-out relay actuation. The main generator lock-out relay actuation caused both Main Generator output breakers to open, resulting in a generator load reject. The load reject/turbine trip initiated a reactor scram. All systems operated as designed and the plant received expected alarms and isolations.

Causes: Preliminary indications are a fault in the UAT (unit auxiliary transformer). The fault appears to be an internal winding secondary fault. There are no indications of a phase to phase or a ground fault. A root cause evaluation is ongoing to determine the cause of the UAT failure.

Corrective Actions: The appropriate procedures were entered and all required notifications were made. The reactor was maintained in hot standby. The plant was restarted using the startup transformer for house loads. Pilgrim is currently looking into several possibilities including replacement and/or repair of the faulted UAT.

Subject: OE16316 - (Update to OE15471) Failure of the Unit 1 Main Transformer

Event Date:	January 15, 2003
Unit Name:	Donald C. Cook Plant Unit 1 / Unit 2
NSSS/A-E:	Westinghouse/American Electric Power
Turbine Manufacturer:	GE (Unit 1)/Brown Boveri (Unit 2)
Docket No./LER No.:	50-315 (Unit 1), 50-316 (Unit 2)
Year Commercial:	1975 (Unit 1), 1976(Unit 2)
Rating:	3250 Mwt/3411 Mwt
ENS System Code(s):	
NSSS Applicability:	

Maintenance Rule:

Abstract: (Update) 1-TR-MAIN-Main Generator OME-81 Output Transformer failed. The apparent cause of the 1-TR-Main failure was an internal fault. There were no identifiable precursor indications prior to the event.

Reason for Message: This is an update to OE15471.

Maintenance Rule Applicability: The Maintenance Rule evaluation has determined this event to be a Functional Failure. The catastrophic failure of the Unit 1 main transformer caused a plant trip and the plant level performance criterion was exceeded. The evaluation also determined that this event was not a Maintenance Preventable Functional Failure.

Description: With Unit 1 operating at 100 percent power, the main output transformer (1-TR-MAIN) failed internally on 1/15/2003, initiating a shutdown of the unit.

The fault ruptured the transformer tank causing the release of burning oil that was controlled by the response of the deluge system, the plant fire brigade, and environmental personnel. This six-year-old transformer failed without any prior indication. There was no annunciator alarms received prior to the fault occurrence. There was also no evidence of any system, plant, or generator transient could be found occurring at the time of, or in the hours before, the failure.

The fault was detected by both sets of differential current relays and the sudden pressure relay on the transformer. These devices operated as designed to trip the associated lockout relays, which opened the 345kV output breakers and tripped the turbine. The opening of the 345kV breakers cleared the fault. However, rotating energy and residual magnetism in the field maintained a voltage on the transformer terminals. This caused a flashover between the high voltage winding and ground that continued for over one second causing extensive burning and arc erosion in the transformer.

The failed transformer is an ELIN 1300 MVA, 345/25kV 3 phase, five leg core form transformer with the windings concentrically arranged on the main legs.

It was manufactured and tested in 1996 and installed in May of 1997. Total in-service operating time was approximately eight hundred days at, or near, full unit load, which is less than 85% of the transformer rating. The transformer was also on backfeed for approximately sixty days during outages. The transformer was out of service and de-energized for most of the twelve hundred days of the extended outage.

Maintenance and test activities and the associated frequencies were reviewed for appropriateness, interval, and evaluation results. Available monitoring and testing techniques were reviewed to ensure that all appropriate activities were being performed. Monitoring data and operational records were reviewed to identify any data or event that could have initiated or signaled a failure. No test results were identified that indicated any deterioration within the transformer or generator. In addition, system conditions did not identify any external event responsible for the failure.

No precursor events or monitored parameter transients were identified during these reviews.

Causes: A forensic disassembly of the failed transformer was conducted on site between May 6 and May 20, 2003 under the direction of a manufacturer's representative. The initial determination that the internal fault occurred between phases on the 26kV side was disproved. The severe burning found on the low voltage leads resulted from the fire. No indication of electrical failure (arcing or melted copper) was found on the low voltage terminals.

Examination of the phase 1 high voltage windings found insulation burning and copper arc damage. There was also severe arc erosion in the area of the high voltage leads exiting the winding and the core clamping steel on phase 1. Examination of the damage and review of the switchyard fault recorder records indicates that the initial fault was a turn-to-turn insulation failure in the high voltage winding. After this fault was cleared, arc products, debris, and gases degraded the insulation between the phase 1 high voltage leads and the core clamping steel. This allowed the voltage being applied during the generator rundown to flash across the gap that was created and added to the fault damage. There is no indication of a low voltage fault, a fault between the windings, or an initial high voltage phase-to-ground fault.

The transformer fault was the result of an insulation failure between turns on the high voltage winding of phase 1. At this time, it is not know if this failure was due to design, materials, or manufacture. The manufacturer is being consulted regarding further cause analysis.

Safety Significance: Safety significance was minimal because all plant systems functioned as designed during and after the event. All transformer protective devices operated correctly; however, the Unit 1 digital fault recorder did not operate and prevented capturing fault data on the generator's contribution to the event.

Corrective Actions: The failed transformer has been removed and the replacement transformer installed.

Subject: OE15024 - Reactor Scram Resulting from Main Transformer Bushing Failure (Related to OE14594)

Abstract: Unit 2 scrammed as a result of a fault in a low-side bushing on the main bank transformer. The root cause of the bushing failure was determined to be thermal deterioration of the condenser of the low voltage bushing on the Main Transformer, resulting in the paper insulation-reaching end of life.

Reason for Message: Provide root cause and corrective action information for the event described in preliminary OE14594.

Event Date:	July 27, 2002
Unit Name:	Browns Ferry Unit 2
NSSS/A-E:	GE/TVA
Turbine Manufacturer:	GE

Maintenance Rule Applicability: Yes

Component Information:
Manufacturer: ASEA
Model Number: Main Bank Transformer low voltage bushing GOH 150/12
Part Number:

Description: This is a follow-up report to OE14594, issued September 13, 2002.

On July 27, 2002, with Unit 2 in steady state operation at 100 percent power, a main generator trip, main turbine trip, and reactor scram occurred. It was subsequently determined that a phase-to-ground fault had occurred in a low-side bushing on main bank transformer 2A.

Causes: The root cause of the bushing failure was determined to be thermal deterioration of the condenser of the low voltage bushing on the Main Transformer, resulting in the paper insulation reaching end of life. Frequent refurbishment activities may have masked the condenser dielectric degradation. Power factor testing was routinely performed.

However, physical strength of the paper could not be predicted by power factor testing, but only by a destructive degree of polymerization test.

Corrective Actions:

- All bushings that are in service for large nuclear site Generator StepUp (GSU) transformers, operating in an enclosed bus duct system, and that has condensers exceeding 20 years of age, will be identified and scheduled for replacement at the next appropriate outage.
- Refurbishment of the GOH-150 bushings will be limited to O-ring and/or seal replacement, and the bushing condensers will remain with the original conductor and mounting flange with the nameplate installed to facilitate trending.

Safety Significance:

Refer to OE14594.

Subject: OE14504 - Reactor Scram due to MPT B Sudden Pressure Relay Actuation (UPDATE TO OE14236)

Abstract

On July 4 the sudden pressure alarm for the “B” Main Power Transformer (MPT) actuated in the Main Control Room at the same time the reactor automatically scrammed from 95 percent reactor power. The sudden pressure alarm was initiated by a malfunction of the sudden pressure relay ISPR). The SPR initiated a Generator trip and lockout. The Generator trip caused a Main Turbine trip and Turbine Control Valve fast closure, resulting in the reactor scram. The SPR trip also initiated the “B” MPT deluge system, and the fire pumps automatically started as expected.

Reason for Message:

Situations should consider reviewing trip logic associated with large transformers to determine if similar weaknesses exist.

Event Date:	July 4, 2002
Unit Name:	Clinton
NSS/A-E:	General Electric/Sargent and Lundy
Turbine:	General Electric
Docket No./LER NO:	50/461
Year Commercial:	1987
Rating:	3475 MWth/
NSSS Applicability:	BWR/PWR
Maintenance Rule Applicability:	No

Component Information (as applicable);	
Manufacturer:	Qualitrol Model Number: 900-02161

Description:

On July 4, 2002, at about 0133 hours, the sudden pressure alarm for the “B” Main power Transformer (MPT) actuated the Main Control Room and at the same time the reactor automatically scrammed. The sudden pressure alarm was initiated by an apparent malfunction of the sudden pressure relay. The sudden pressure relay initiated a Main Generator trip and lockout. The generator trip caused a Main Turbine trip and Turbine Control Valve fast closure, resulting in the reactor scram. The sudden pressure relay trip also initiated the “B” MPT deluge system, and the fire pumps automatically started as expected.

A prompt investigation team performed an immediate fact-finding to identify the suspected apparent cause of the event. The prompt investigation team concluded that the suspected apparent cause was hardware related and identified no human performance deficiencies.

The initial investigation of this event identified that the sudden pressure relay actuated without a true fault overpressure condition in the transformer. The relay is designed with a dead range (no trips) of 1.25 to 1.50 psig and a trip range of 3.00 to 3.25. When tested after the trip, the relay was found to trip 6 out of 8 times at the 1.50 psig level indicating that the relay was overly sensitive. Based on these: as-found” testing results, the relay was quarantined and sent to the original equipment manufacturer (Qualitrol) for failure analysis.

The sudden pressure relays installed in the 4 MPTs (including one spare MPT) were factory installed new relays for the new MPTs supplied by VA Tech – Elin. The new MPTs were recently installed (May 2002) during the last refueling outage as part of extended power uprate.

The investigation confirmed that no other faults or disturbances existed on the 345-kilovot transmission lines prior to the trip of the transformer.

An inspection of the ‘B” MPT identified no physical damage to the MPT.

The extent of condition for this event is not limited to the main power transformers. Sudden pressure relays are also used in the protective scheme for the Unit Auxiliary Transformers (UATs). Although, Westinghouse manufactures the relays on the UATs (ABB Part # 4432A-45 Group 2), their operation is similar to the Qualitrol relays. The
UAT sudden pressure relay trip logic is identical to the non-fault tolerant trip logic used for the MPTs and therefore a false SPR actuation will result in a turbine trip and reactor scram. The unit trip on loss of a UAT is necessary because there are no circuit breakers on the power lines that tie the UATs to the main generator and the MPTs.

The Emergency Reserve Auxiliary Transformer (ERAT) and the Reserve Auxiliary Transformer (RAT) also posses' 1-out-of 1 trip logic schemes that utilize the Qualitrol sudden pressure relay. In their normal lineup with the RAT supplying the vital bases and the ERAT the alternate source for the vital buses, a trip of the RA or ERAT would not resulting a unit trip. Although the trip schemes for these transformers would not normally result in a trip of the unit, a trip of the RAT when supplying BOP loads in a non-standard lineup would result in a unit trip.

Cause(s):
The causes of this event are attributed to a false actuation of the sudden pressure relay. The root cause for the false actuation was a latent defect in the bimetal of the relay control orifice that likely occurred during the manufacturing process. This defect resulted in the bimetal orifice becoming more sensitive when exposed to higher operating temperatures.

Safety Significance:

The plant responded normally to the reactor scram. The response and behavior of the plant during this event were compared to the Generator Load Rejection transient discussed in Chapter 15 of the Updated Safety Analysis Report and the General Electric Transient Safety Analysis Report and were determined to bed within those analyses. This event posed no challenges to fission product barriers. All systems responded as required for an event without bypass valve failure.

Previous Event History:
Clinton Power Station has experienced two previous sudden pressure relay false actuations. The first occurred in 1989 when MPT “C” Qualitrol sudden pressure relay tripped due to accumulated moisture in the relay that short circuited the relay operating contacts. This type of event occurred at a number of different facilities during this time frame and resulted in an alteration to the relays design to provide additional assurance that accumulated moisture would be minimized and therefore less likely to result in false operation of the relay. The second event occurred March, 2002 when water intrusion into the control cabinet of the ERAT resulted in a short circuit of the control card for the sudden pressure relay and subsequent trip of the transformer. Neither of these events is directly related to the MPT “b” trip that occurred on July 4, 2002.

Corrective Actions:
The faulty sudden pressure relay in the ‘B’ MPT was replaced with the relay from the spare MPT (‘D’MPT). The sudden pressure relays for the ‘A’ and ‘C’ M’Ts and the replacement “B” MPT relay were tested and verified to operate properly.

A design change will be implemented to remove the station’s vulnerability to a single failure of the Sudden Pressure Relay that results in plant shutdown. The design change will modify the sudden pressure relay protection scheme from a one-out-of-one trip logic to fault tolerant trip logic in all 4 MPTs.

The installed sudden pressure relays will be tested quarterly until the new relay trip logic is installed.

Submit a proposal to the Plant Health Committee to change the trip logic on UAT 1A, UAT 1B and ERAT from their current 1-out-of-1 schemes to a fault tolerant scheme.

Assure that the RAT that will be installed in the next refueling outage will include a fault tolerant logic scheme for the sudden pressure relays.

OE12812 – Main power Transformer 2 Taken off line due to Excessive Gassing

Event Date:	09/01/01
Unit Name:	Dresden unit 2
NSSS/A-E	GE /Sargent & Lundy
Turbine Manufacturer:	GE
Docket No./LER No:	50-237
Year Commercial	1971
Rating	794 MWe
EIIS System Code(s)	EB, AD, BN
NSSS Applicability	BWR/PWR

Maintenance Rule Applicability:
This event did not result in a Maintenance Rule Functional Failure.

Component Information (as applicable):

Manufacturer:	General Electric
Type:	GUS, 345-17.1kV, 850/952 MVA, FOA 3 Phase

Description:

On 6/25/01, the weekly oil sample analysis indicated an adverse increase in the total dissolved combustible gas (TDCG) from 1267 to 2469 ppm. Additional confirmatory samples were taken over the next three days and the results indicated an increase of approximately 40 ppm per day. Sampling was increased to twice a week. Additionally, plans were formulated to initiate nitrogen purging and consideration given to MVAR load limiting. Purging the void space would limit the build up of hydrogen and reduce TDCG. Nitrogen purging was implemented on July 6, 2001 and initially performed three times a week, then increased to 5 times a week on July 11, 2001. These actions were successful in purging the gases faster than they were being generated. The TDCG on August 9, 2001 was 1795 ppm. The subsequent sample on August 13, 2001 indicated a TDCG concentration of 2302 ppm. Twenty-four hour nitrogen purging was immediately implemented and MVAR loading further limited to 100 MVARs.

On 8/27/01, the trends on MPT 2 total dissolved combustible gas (TDCG) concentration showed an accelerated rate of increase. Unit load was reduced to 720 MWe (727 MVA). This resulted in an initial decrease in the TDCG. However, the TDCGC concentration began increasing indicating MWe maintaining MVARs at + 50 MVARs. Based on degrading conditions, the decision was made to take the transformer off-line and effect repairs.

Causes:
Initially the gases were predominately hot metal gases attributed to heating of the core steel. Gases that indicate winding or insulation failure were not presented in abnormal concentrations. Insufficient core cooling contributed to core steel heating. The insufficient core cooling is a function of the design and attributed to a component failure. Prior to securing the transformer, low energy electrical fault related gases (methane and hydrogen) were generated at an increased rate. Based on the continually degrading conditions, the decision was made to take the transformer off-line and effect repairs.

Safety Significance:

This event does not represent a safety significant event.

Previous Event History:
Dresden Main Power Transformer 3 (MPT-3) was replaced in April 1998 due to gassing concerns.

Corrective Actions:

Spanner nuts and bolted connections for the flux shields were inspected; cleaned and re-tightened as required. Two spanner nuts were found missing. One was found on top of the oil box near the HV coil. The other spanner nut is believed to have been left out in a previous maintenance window (circa. 1993). The high side “A” phase winding crossover lead was found in an excessive heated condition. The affected section of cable was removed. Additionally, a root cause is in progress.

Event Title: Component Failure Causes Turbine Trip and Reactor Scram

Event Summary:

On March 28, 2001, while at 100 percent power, Hatch unit 1 experienced an automatic reactor scram on turbine control valve fast closure caused by a turbine trip. Actuation of the phase 2 and 3 differential relays for unit auxiliary transformer 1B resulted in actuation of a lockout relay that tripped the generator and turbine. Following the scram, water level decreased due to void collapse from the rapid reduction in power resulting in closure of Group 2 and the outboard Group 5 primary containment isolation valves and automatic initiation of the Reactor Core Isolation Cooling and High Pressure Coolant Injection systems. The low level initiation signal cleared before either system could inject water to the vessel. The outboard secondary containment dampers automatically isolated and all trains of the Unit 1 and Unit 2 Standby Gas Treatment systems automatically started on low water level. Pressure reached a maximum value of 1127 psig and fie of eleven safety/relief valves lifted to reduce pressure. Pressure did not reach the nominal actuation setpoints for the remaining safety/relief valves. This event was caused by an internal fault in unit auxiliary transformer 1B. An inspection revealed a turn-to-turn failure caused extensive damage to the high side winding of transformer phase 3. The root causes of the transformer internal fault were not determined. The unit auxiliary transformer was removed from service and taken to an off-site facility for further inspection. The transformer loads will be supplied from their alternate power supply until a new transformer can be procured and installed. This event is NOT SIGNIFICANT because all systems functioned as expected and per design. Vessel water level was maintained well above the top of the active fuel throughout the transient. This event is NOTEWORTHY because an equipment failure resulted in an automatic reactor scram and affected until reliability.

Event Number:	321-010328-1
Event Date:	03/28/02
INPO Change Date:	06/06/2001
Unit:	321, Hatch 1
NSSS Vendor:	General Electric;
NSSS Type:	BWR Boiling Water Reactor
Country:	USA
INPO Significance:	Noteworthy Event
Initial Plant Condition:	Steady State Power, 100% Power
Event Descriptor:	Component Failure

Event Descriptor: Switchyard Problem
Event Descriptor: Unplanned Capability Loss
Event Descriptor: TZ
Event Descriptor: TA

Identified Component/System Failures:

Component	System	Failure Consequence	Equipment Casual Factor
TRANSF	XBO	Initiated the Event	Other Equipment Failure

Keywords: SCRAM, COMPONENET, TRANSFORMER, FAULT, REACTOR SCRAM, ELECTRICAL EQUIPMENT

SCRAM Information:
Time of Scram: 18:53

Type of Scram: Automatic
Reactor Critical
Generator Synched

Initiating Transient: General Trip

System in which Problem Occurred: Electrical Distribution; Power Sources

Scram Signal: Turbine Trip – Turbine Control Valve Fast Closure

Primary Source Document: LICENSE EVENT REPORT, 321-01002, 05/21/2001

OE24848 - Main Transformer Failure (Indian Point Unit 3)

ABSTRACT:

An automatic trip occurred at Indian Point Unit 3 with the unit at 91% power due to an electrical fault on the 31 Main Transformer B phase. Various protective relays actuated as designed in response to the fault to minimize equipment damage. At 11:11 a fire was reported at the transformer. The plant fire brigade was activated to extinguish a fire that developed on top of the transformer as a result of the fault. The fire was quickly extinguished by the actuation of the 31 Main Transformer deluge system, the primary extinguishing agent. The brigade responded properly and took actions to ensure complete extinguishment. The fire started from oil that ignited from the failure of the 'B' phase high voltage bushing on 31 Main Transformer. The fire/damage was isolated to 31 Main Transformer. An Unusual Event was declared due to the fire and explosion that occurred from the fault, the Unusual Event was terminated at 12:47.

REASON FOR MESSAGE:

Provide the industry the results from an investigation into a main transformer failure that resulted in an automatic unit trip and the transformers subsequent replacement.

EVENT DATE: April 6, 2007
UNIT NAME: Indian Point Unit 3
NSSS/A-E: Westinghouse/UE&C
TURBINE MANUFACTURER: Westinghouse/ABB
MAINTENANCE RULE APPLICABILITY: No
COMPONENT INFORMATION: Main Transformer 'B' Phase Bushing
MANUFACTURER: General Electric (bushing manufactured in 1969)
MODEL NUMBER: GE Type U Oil Filled Condenser Bushing
SITE CONDITION REPORT: CR-IP3-2007-01834

DESCRIPTION:

An investigation following the fault included performing an internal tank inspection, bushing inspection, research of industry OE (Operating Experience) regarding GE (General Electric) U type bushings, vendor data concerning U type bushings, work history and oil quality analysis. The investigation was focused on determining the cause for the fault. KT (Kepnor Tregoe) analysis was performed to capture the types of failures/causes that could occur with high voltage bushings. Documentation exists that U type bushings (and other types in general) failures occur quickly and in many cases are undetectable right up to the point of failure. All of the required maintenance and test practices as per industry standards were performed and documented in the PM program.

The transformer failure resulted in destroying most of the direct evidence and therefore, a root cause could not definitively be determined. The bushing temperature monitoring and Doble values were acceptable prior to the event. This event appears to be the result of an old bushing that despite its design weaknesses has operated well for 30 years and failed in a fashion that is consistent with industry literature.

In addition, IPEC commissioned Doble Engineering to perform a condition assessment of the Indian Point Unit 3 main transformers in May, 2004 as part of the SPU (stretch power uprate project). The report recommendations did not find any data that precluded unit 3 from going to its SPU values. The report does echo findings similar to that in the RCA (Root Cause Analysis) where there was limited electrical test data available for the transformer. Testing of both the 32 GE and the 31 Smit Nymegen transformers has been performed as part of 31 Main Transformer replacement with satisfactory results.

There are numerous instances sighting the failure rate for the GE U type bushings. It is important to note that this Doble Engineering report does not recommend the wholesale removal of these bushings. This agrees with industry guidelines that the GE U type bushings are acceptable for service provided they are within the manufacturers guidelines

CAUSES:

Based on the fact that the event was a catastrophic failure of the bushing destroying most of the component, and leaving little evidence for root cause and based on previous discussions and analysis, the root cause could not be determined. The failure resulted in destroying most of the direct evidence. The most probable root causes for the bushing fault are from the design weaknesses associated with GE U type bushings. The design weaknesses as documented in ABB (Asea Brown Boveri) and GE publications are associated with:

1. Excessive cycling of the bushing leading to developing gas bubbles (voids) in the bushing oil. The gas bubbles (voids) if developed would lead to partial discharge and tracking resulting in increased dielectric-losses. The design flaw pertains to gaps that existed at the ends of the internal paper/core allowing for the formation of gas bubbles (voids).
2. The bushing Condenser design incorporated printed paper layers with plain kraft paper in between the printed layers. The ink used to develop capacitance properties migrated on to the plain kraft paper allowing for voltage tracking across the paper causing corona action and burning. In addition, the paper originally used was too thin which resulted in premature degradation.

3. The bushing 'flex seal' design. The flex seal design originally used was developed to allow for expansion and contraction of the center conductor during thermal cycling. The flex seal was basically a copper diaphragm which flexes or moves during thermal cycling. The flex seal movement may result in mechanical stresses which could cause cracks and compromise the seal resulting in leaks. In this case, thermography was performed at 50% power with no indications of a heating issue. The 100% power thermography measurement did not occur since the failure occurred at 91% power.
4. Age of the 'B' phase GE type U bushing. The bushing was an original early design which operated and was subject to cycling for 30 years.

CORRECTIVE ACTIONS:

- Revise all Transformer outage PM procedures to require Engineering review / trending of test data and to specify acceptance criteria for PF and Capacitance testing.
- Establish Doble acceptance criteria for large transformers and trend all available Doble data for transformers and provide access on a common median.
- Review vendor failure analysis report and provide recommendations as necessary.
- Review IPEC Main transformer vendor manuals and incorporate any updates that are not reflected in existing revisions.
- Review the Doble 31 and 32 Main Transformer power uprate assessment report from 2004 to ensure that recommendations are incorporated into the large transformer PM program as necessary.

SAFETY SIGNIFICANCE:

There was no radiological or nuclear safety significance involved with this event. The event was limited to the Unit 3 transformer yard which is not a radiological controlled area.

Industrial safety significance was the catastrophic failure of the bushing with shattering of the bushing material throughout the transformer yard. There were no personnel present in the yard at the time of the event so there were no injuries involved.