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UNITED STATES
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

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In re:

License Renewal Application Submitted by
Entergy Nuclear Indian Point 2, LLC,
Entergy Nuclear Indian Point 3, LLC, and
Entergy Nuclear Operations, Inc.

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Docket Nos. 50-247-LR; 50-286-LR

ASLBP No. 07-858-03-LR-BD01

DPR-26, DPR-64

September 23, 2009

THE STATE OF NEW YORK'S
COUNTER-STATEMENT OF MATERIAL FACTS

The State of New York respectfully submits the following counter-statement in response to Entergy's August 14, 2009 Statement of Material Facts. With respect to Entergy's August 14, 2009 statement, the State of New York responds as follows:

GENERAL OBJECTIONS

The State of New York makes the following general objections to the August 14, 2009 statement:

1. The relevant NRC Regulation, 10 C.F.R. Section 2.710(b), requires that "[a]ffidavits must set forth the facts that would be admissible in evidence, and must demonstrate affirmatively that the affiant is competent to testify to the matters stated in the affidavit."

2. A large portion of what Entergy has submitted as statements of material fact consist of either summaries of the contents of documents, statements of law, or legal argument. The referenced documents and regulations themselves are the best evidence of their content and speak for themselves.

3. Since none of the affiants offered by Entergy are lawyers, they are not competent to offer legal opinions and Entergy makes no effort in these affiants' affidavits to qualify them as expert witnesses on matters of law. The fact that as laymen they may have had to work with an awareness of these legal matters does not qualify them as expert witnesses to testify to what is the law. If the legal opinions were offered only to demonstrate what the affiant believed was the law, and not for the truth of the assertion made, it would not be

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affiant believed was the law, and not for the truth of the assertion made, it would not be objectionable. In addition, legal opinions are not "facts" and thus are inappropriate for a statement of material facts.

SPECIFIC RESPONSES AND COUNTER-STATEMENTS[1]

A. **Transformer Operation and Transformer Properties**

1. *Transformer operation is based on two scientific principles. First, an electric current flowing through a wire will produce a magnetic field.* Undisputed. *Second, a changing magnetic field within a coil of wire will produce a voltage across the ends of the coil. Dobbs Decl. at ¶ 7.* Undisputed; however, the State disputes any implication or statement that changes in current or voltage are properties of the transformer component itself. Declaration of Paul Blanch, executed September 22, 2009 ("Blanch Decl.") at ¶¶ 16-17, 26, 32-33. *Thus, in its most basic form, a transformer is formed by winding two coils of wire around the same iron form, called a core. Id. at ¶ 9.* Undisputed.

2. *One of the coils of wire, the primary, if excited by an alternating current, will create a magnetic field around the wire.* Undisputed. *Because the wire is wrapped in a coil, the magnetism produced by each wrap of wire combines with the magnetic fields emanating from the other wraps to produce a strong magnetic field within the core. Id. at ¶ 9.* Undisputed.

3. *The alternating current that flows through the winding establishes a time-varying magnetic flux (i.e., the strength of the magnetic field is continuously increasing or decreasing), some of which links or "couples" with the secondary winding and induces an alternating voltage*

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[1]Because Entergy's Statement of Undisputed Material Fact contains multiple statements per paragraph, often the State could not characterize an entire paragraph as disputed or undisputed. To clarify the State's responses, the State includes Entergy's original statements here in italics, followed by the State's response.

across that coil. Undisputed if "the winding" means the primary winding in a transformer. *The magnitude of this voltage is proportional to the ratio of the number of turns on the secondary and primary coils.* Undisputed. See also Blanch Decl. at ¶ 16. *This is referred to as the "turns ratio." Id. at ¶¶ 9-11, 18.* Undisputed if Entergy intended "this" to refer to the "ratio between the number of turns in the primary coil and the number of turns in the secondary coil."

4. *If the secondary winding is connected to a load and current is allowed to flow into that load, then power will be transferred to that load.* Undisputed if this sentence refers to a secondary coil in a operating transformer. *Thus, the essence of a transformer is the process by which it accepts voltage and current as an input and then "transforms" that voltage and current to different values at its output(s). Id. at ¶¶ 6, 14; Craig Decl. at ¶¶ 21-22.* Disputed. A transformer is an electrical device that can convert alternating currents and voltages to different voltages and currents or provide isolation of circuits; a transformer does not contain moving parts nor do its configuration or properties change during intended use. Blanch Decl. at ¶¶ 16, 17, 18. Also disputed is any implication or statement that any changes in the current and voltage that pass through a transformer are "properties" of the transformer or that the transformer component itself changes. Blanch Decl. at ¶¶ 32-33; see also id. at ¶¶ 26-31 (comparison of other components and systems specifically listed as included within regulatory scope).

5. *A transformer performs its intended function by stepping down voltage from a higher to a lower value, stepping up voltage from a lower to a higher value, or providing isolation to a load. Dobbs Decl. at ¶ 18; Craig Decl. at ¶ 26.* Undisputed.

6. *The voltages and currents associated with a transformer are integral properties of a transformer.* Disputed; the current entering a transformer is controlled by factors outside the

transformer, and voltage is an aspect of the entering current rather than a property of the transformer. Blanch Decl. at ¶ 17. Similarly, the current leaving a transformer from the secondary coil is not a property of the transformer and voltage is a property of that current. Blanch Decl. at ¶¶ 26, 33. *Without voltage and current, there is no transformer operation.* Undisputed. *The voltages, current, and the associated magnetic field all must vary in time to achieve transformer operation.* Disputed; the State disputes any implication or statement that any changes in the current and voltage that pass through a transformer are "properties" of the transformer or that the transformer's configuration or properties change when current flows into a transformer. Blanch Decl. at ¶¶ 17; 32-33. When an electrical current flows into a transformer, that electrical input will create an electromagnetic field within the transformer. Conversely, when there is no current flow into the transformer, there is no magnetic field; the coils and the core do not produce a magnetic field on their own when there is no incoming electrical current. Blanch Decl. at ¶ 17. *Moreover, the voltage and currents vary whenever load conditions change. Dobbs Decl. at ¶¶ 16, 21-22.* Undisputed, but not material, because the voltage and currents are not properties of the transformer. Blanch Decl. at ¶ 17. *Therefore, all transformers perform their intended functions through a change in state (i.e., changes in voltage and current properties). Id. at ¶ 52.* Disputed. The transformer does not change state even though the current that is an input to the transformer and the voltage that is a property of that current do change. Blanch Decl. at ¶¶ 17, 26. Moreover, a passive transformer is unlike an active transistor. Blanch Decl. at ¶¶ 36-37. Instead, transformers are like electrical cables, pipes, or other components that are included within the scope of 10 C.F.R. § 54(a)(1)(i). Blanch Decl. at ¶¶ 27-30 & Table - Comparison of Various Structures and Components. The State disputes any implication or statement that any changes in the current and voltage that pass through a transformer are "properties" of the transformer or that the transformer's configuration or properties change when current flows into a transformer. Blanch Decl. at ¶¶ 17; 32-33.

7. *Neither the complexity of transformer design nor the occurrence of electrical and magnetic losses during operation alters these conclusions.* Undisputed if by "these conclusions" Entergy means those set out in its paragraphs 1-6, and if the conclusions are corrected as set forth in the State's responses 1-6. *These scientific principles apply equally to all transformers from the smallest electronic unit to the largest distribution transformer. Id. at ¶ 21.* Undisputed if by "these scientific principles" Entergy means those stated in its paragraphs 1-6, and if the "principles" are corrected as set forth in the State's responses 1-6.

8. *The voltages, currents, and heat signature of a transformer are all properties that are peculiar to a given unit, change as the transformer performs its intended function, and are readily monitorable while the transformer is performing its intended function, providing an indication as to the operational health of a transformer.* Disputed for the reasons stated in ¶ 6 above and for other reasons. Many conditions of concern in aging, such as insulation degradation, are not readily analyzed and inspected, particularly where the monitoring is focused, as it is at Indian Point, on the "performance" or "output" of the transformer and not also on the aging degradation mechanisms of the transformer and its components which may be vulnerable to failure even though they continue to fulfill their performance functions. Blanch Decl. at ¶¶ 49-53. During operation no part of the transformer moves or changes to manipulate the currents in either circuit. Blanch Decl. at ¶¶ 16-17. *For example, the temperature of a transformer or its infrared signature, which changes with load, can be monitored to verify*

proper operation. Id. at ¶¶ 25-27. Undisputed, but, as noted, monitoring component performance does not provide assurance that a failure will not occur due to degradation of components of the transformer. Blanch Decl. at ¶¶ 44-53.

B. <u>Ongoing Monitoring and Maintenance of Electrical Transformers</u>

9. *The potential degradation of the ability of a transformer to perform its intended function is monitorable by changes in the electrical performance of the transformer and/or its associated circuits. Moreover, certain IP2 and IP3 transformers, including those necessary for compliance with 10 C.F.R. § 50.48 and 50.63, are subject to direct, ongoing surveillance, monitoring, maintenance, and inspection. Rucker Decl. at ¶ 19.* The State disputes that monitoring transformer performance can identify all potential degradation of all transformers that would be within the scope of Part 54. Blanch Decl. at ¶ 52; <u>see</u> <u>also</u> <u>id</u>. <u>at</u> ¶¶ 44-53.

10. *For certain transformers, particularly large power transformers, instrumentation is provided to detect degrading conditions.* Disputed. Instrumentation cannot detect all aging degradation mechanisms or their progression and there are aging management techniques that can and should be done as indicated in Electrical Power Research Institute, Life Cycle Management Planning Sourcebooks, Volume 4: Large Power Transformers, Final Report, 1007422 (Mar. 2003) and IEEE Power Engineering Society, IEEE Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformers, C57.140 (Apr. 27, 2007). Blanch Decl. ¶¶ 49-53. *For example, if voltage conditions exceed defined acceptable ranges, then an alarm condition will be sounded automatically to alert operators to the condition (e.g., excessive load on transformer, transformer fault, undervoltage conditions).* Undisputed as to transformers with appropriate instrumentation; however, by its terms, this statement applies only to "certain" (not

"all") transformers; moreover, excessive load and undervoltage can be due to factors outside transformers and the performance monitoring cannot detect all age related transformer component degradation. Blanch Decl. at ¶¶ 49-53. *These indicators or alarms appear on supervisory panels in the IP2 and IP3 control rooms or on individual transformer panels that are checked during frequent operator rounds.* Undisputed as to transformers with appropriate instrumentation, but disputed as to whether these indicators and alarms are adequate to detect all transformer degradation. Blanch Decl. at ¶¶ 49-53. *Established station procedures require appropriate corrective actions if transformer performance is outside acceptable ranges.* Disputed. There is substantial evidence (*see, e.g.*, NRC Information Notice 2009-10, Transformer Failures - Recent Operating Experience (July 7, 2009), ADAMS ML090540218 ("IN 2009-10"); Electrical Power Research Institute, Life Cycle Management Planning Sourcebooks, Volume 4: Large Power Transformers, Final Report, 1007422 (Mar. 2003) ("2003 EPRI Report")) that current procedures for monitoring the performance of transformers in use at facilities like Indian Point are not adequate to detect, in advance of failure, malfunctions or degradations in the transformers. Blanch Decl. at ¶¶ 49-53. *Such procedures are included in activities such as personnel training and quality assurance audits, and subject to periodic NRC inspection. Id. at ¶ 20.* Undisputed that the procedures used by Indian Point are subject to those activities, but disputed as to whether those activities provide the level of monitoring and management sufficient to demonstrate that the transformers will reliably perform their intended functions during extended operation. Blanch Decl. at ¶¶ 49-52.

11. *Entergy has implemented preventive maintenance, inspection, and surveillance programs and procedures to manage "active" systems and components, including transformers*

required for compliance with 10 C.F.R. § 50.48 and 50.63. Disputed. The State disputes the assertion that transformers are active components. Blanch Decl. at ¶¶ 17, 32, 33 (transformers have no moving parts). *These programs and procedures, some of which are necessary to comply with the NRC's Maintenance Rule (10 C.F.R. § 50.65), are intended to identify and correct potential degradation (including aging) issues associated with active systems and components.* Disputed as to whether Entergy's existing programs and procedures are adequate to detect all significant transformer degradation. Blanch Decl. at ¶¶ 44-53. *These activities include, as appropriate, periodic cleaning and inspections of transformers, as well as instrument checks, functional tests, and calibration functional tests.* Disputed as to whether Entergy's existing programs and procedures are adequate to detect all significant transformer degradation. Blanch Decl. at ¶¶ 41-53. *The data and information from such tests and performance monitoring programs are analyzed and trended to detect potential degradation of transformer performance (e.g., a change in the electrical performance of the transformer or the associated circuits). Id. at ¶ 21.* Undisputed that the licensee may perform some activities on some transformers; however, the State disputes that such activities are adequate to manage the aging of all transformers that would be within the scope of Part 54. Blanch Decl. at ¶¶ 44-53; see also NRC Information Notice 2009-10, Transformer Failures - Recent Operating Experience, July 7, 2009, ADAMS ML090540218, EPRI Life Cycle Management Planning Sourcebooks, Volume 4, Large Power Transformers, [1007422], March 2003; EPRI, Large Transformer End-of-Expected-Life Considerations and the Need for Planning [1013566], December 2006; IEEE Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformers [IEEE Std C57.140-2006] 2006; Sandia National Laboratories, Aging Management Guideline for

Commercial Nuclear Power Plants Power and Distribution Transformers, SAND93-7068 • UC-523 Unlimited Release, May 1994.

C. The Scoping and Screening Requirements of 10 C.F.R. Part 54

12. *The NRC's License Renewal Rule (10 C.F.R. Part 54) for nuclear power plants is based on two well-established principles. First, with the exception of age-related degradation unique to life extension for certain passive and long-lived structures and components, the NRC regulatory process is deemed adequate to ensure that currently operating plants will continue to maintain adequate levels of safety during the period of extended operation. Second, each plant's current licensing basis ("CLB") is required to be maintained during the renewal term in the same manner and to the same extent as during the original licensing term. Final Rule, Nuclear Power Plant License Renewal; Revisions, 60 Fed. Reg. 22,461, 22,464 (May 8, 1995).* Disputed. These statements are legal conclusions that are not supported by a competent expert.

13. *NRC regulations require a license renewal applicant to (1) identify the structures, systems, and components ("SSCs") within the scope of 10 C.F.R. Part 54 and (2) identify the structures and components subject to aging management review ("AMR") based on their intended functions. These two processes are commonly referred to, respectively, as "scoping" and "screening." Rucker Decl. at ¶ 6; 10 C.F.R. §§ 54.4, 54.21.* Disputed. These statements are legal conclusions that are not supported by a competent expert.

14. *The purpose of "scoping" is to identify all plant SSCs that are safety-related or whose failure could affect safety-related functions, or that are relied on to demonstrate compliance with the NRC regulations specified in 10 C.F.R. 54.4. Rucker Decl. at ¶ 6.* Disputed. These statements are legal conclusions that are not supported by a competent expert.

15. *The purpose of "screening" process is to determine which in-scope structures and components are subject to AMR. Rucker Decl. at ¶¶ 9, 14; 10 C.F.R. § 54.21(a)(1).* Disputed. These statements are legal conclusions that are not supported by a competent expert.

16. *Part 54 excludes from the scope of AMR those structures and components that (1) perform their intended functions with moving parts or a change in configuration or properties or (2) are replaced based on qualified life or specified time period. Rucker Decl. at ¶ 8; 10 C.F.R. § 54.21(a)(1)(i)-(ii).* Disputed. These statements are legal conclusions that are not supported by a competent expert.

17. *Only passive, long-lived structures and components within the scope of license renewal are subject to AMR. Passive structures and components are those that perform their function without a change in configuration or properties. Long-lived items are those that are not*

subject to replacement based on a qualified life or specified time period. Rucker Decl. at ¶ 8; Craig Decl. at ¶¶ 9- 10; 10 C.F.R. § 54.21(a)(1)(i)-(ii); Final Rule, Nuclear Power Plant License Renewal; Revisions, 60 Fed. Reg. at 22,477-78. Disputed. These statements are legal conclusions that are not supported by a competent expert.

18. *The Commission has stated that "a change in configuration or properties" should be interpreted to include "a change in state." Dobbs Decl. at ¶ 42; Craig Decl. at ¶ 14; 60 Fed. Reg. at 22,477. Therefore, a structure or component that performs an "active" function, including one that can "change its state," is not subject to AMR. Dobbs Decl. at ¶ 44-45; Craig Decl. at ¶ 14, Final Rule, Nuclear Power Plant License Renewal; Revisions, 60 Fed. Reg. at 22,477.* Disputed. These statements are legal conclusions that are not supported by a competent

expert.

19. *Part 54 lists examples of structures and components that are excluded from AMR because they perform "active" functions. The examples of AMR-excluded systems or components include, "but are not limited to," "pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies." 10 C.F.R. § 54.21(a)(1)(i); Craig Decl. at ¶ 16.* Undisputed except to the extent these statements are legal conclusions that are not supported by a competent expert.

D. <u>The "Scoping" Process as Applied to IP2 and IP3 Transformers</u>

20. *During the scoping process, Entergy used a bounding approach for plant electrical and instrumentation and control ("I&C") systems and components by including in the scope of license renewal all plant electrical and I&C systems (as well as electrical and I&C components in mechanical systems). Consequently, Entergy included in the scope of license renewal all plant*

electrical equipment, including all plant transformers, including those that perform a function necessary to demonstrate compliance with 10 C.F.R. §§ 50.48 and 50.63. LRA Tables 2.2-1b-IP2 and 2.2-1b-IP3 list the electrical and I&C systems within the scope of license renewal for IP2 and IP3, respectively. Rucker Decl. at ¶¶ 10-11; LRA at 2.2-12 to 2.2-16. Not disputed at this time pending the development of discovery and the contention; however, the State does dispute the implication or argument that Entergy included all safety related transformers in its aging management review.

21. *In addition to the plant electrical SSCs, and in accordance with NRC guidance, Entergy included in the scope of license renewal switchyard components (including the associated transformers) that restore offsite power following a station blackout ("SBO") event. Rucker Decl. at ¶¶ 12-13; LRA at 2.5-1 to 2.5-2.* Undisputed as to what Entergy included and disputed as to whether what was done was in accordance with NRC guidance. The latter is a legal conclusion and is not offered by a competent expert on the law.

22. *By using a bounding approach to scoping for electrical and I&C equipment, Entergy included in the scope of license renewal all electrical equipment, including all transformers that perform a function necessary to demonstrate compliance with 10 C.F.R. §§ 50.48 and 50.63. Rucker Decl. at ¶¶ 11-13.* Disputed. The statement constitutes a legal argument and conclusion. The State disputes that Entergy included all safety related transformers in its aging management review.

E. <u>The "Screening" Process as Applied to IP2 and IP3 Transformers</u>

23. *Entergy grouped the total population of in-scope electrical components into component types, and compared these component types to those in NEI 95-10, Appendix B to identify passive component types. The passive component types were identified as commodity groups, which include similar electrical and I&C components with common characteristics. Entergy then identified component-level intended functions of the commodity groups. Rucker Decl. at 15; LRA at 2.5-2.* Undisputed as to what Entergy did, but disputed to the extent it is implied that what Entergy did properly categorized all passive components. The State disputes that Entergy included all safety related transformers in its aging management review

24. *As Entergy examined the intended functions of these commodity groups, certain commodity groups and specific plant systems were eliminated from further review based on Section 54.21(a)(1)(i).* Undisputed that Entergy made the referenced determination, but disputed as to the validity and significance of Entergy's determination. Whether transformers may be eliminated from further review is a legal matter as to which no admissible affiant statement has been offered. *In conducting this process, Entergy followed NRC regulations and the recommendations of NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 C.F.R. Part 54 - The License Renewal Rule," Revision 6 (June 2005).* Disputed as to compliance with NRC regulations and undisputed as to whether Entergy follows NEI 95-10. Disputed at to whether a document prepared by a private entity (NEI 95-10) has any legal effect or relevance to the contention. In addition, whether what Entergy has done complies with NRC regulations is a legal matter as to which no admissible affiant statement has been offered. *The NRC has endorsed this approach in Regulatory Guide 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Nuclear Power Plant Operating Licenses," Revision 1 (September 2005). Rucker Decl. at ¶¶ 14-15; LRA at 2.5-2.* Disputed. The State disputes this statement on various grounds. To begin with, the phrase "NRC has endorsed this approach" incorrectly implies that five NRC Commissioners who were previously vetted and approved by the United States Senate reviewed, analyzed, and voted on the use of NEI 95-10 or Regulatory Guide 1.188 as the basis for deciding whether or not transformers are active or passive components. At most, the Regulatory Guide is what NRC Staff has endorsed. In addition, what the NRC has or has not endorsed and the legal import of any such endorsement are legal matters as to which the movant had not offered an admissible affiant statement.

25. *Appendix B to NEI 95-10 indicates that transformers are not subject to AMR in accordance with 10 C.F.R. § 54.21(a)(1)(i) because they are "active" components. Table 2.1-5 of the NRC's Standard Review Plan for license renewal also indicates that transformers are not passive structures or components subject to AMR under 10 C.F.R. § 54.21(a)(a)(i). Rucker Decl. at ¶ 17; NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" at 2.1-23 (Table 2.1-5, Item 104) (Sept. 2005).* Disputed. Neither NEI 95-10 nor NUREG 1800, Revision 1, which sets out Staff's Standard Review Plan, is a statement of NRC policy. The Nuclear Energy Institute (NEI) is trade association of nuclear utilities and its documents have no legal force in these proceedings. NUREG 1800 is merely a description of how the NRC staff will conduct its review of license renewal applications. "The Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR) provides guidance to Nuclear Regulatory Commission staff reviewers in the Office of Nuclear Reactor Regulation." *See* NUREG 1800, Rev. 1, at iii.

26. *Entergy identified two passive electrical and I&C commodity groups as meeting the 10 C.F.R. § 54.21(a)(1)(i) criterion and, therefore, as subject to AMR. Those commodity groups are (1) high voltage insulators and (2) cables and connections, bus, electrical portions of electrical and I&C penetration assemblies, fuse holders outside of cabinets of active electrical systems and components. These two commodity groups were further divided into the component types and commodity groups listed on page 2.5-2 of the LRA. LRA Table 2.5-1 lists the specific component types or commodity groups that are subject to AMR along with their intended functions. Rucker Decl. at ¶ 16; LRA at 2.5-2 to 2.5-4.* Undisputed as to what Entergy did, and disputed as to whether what they did conformed to Commission regulations.

27. *Entergy determined that all other electrical and I&C commodity groups are active and, therefore, not subject to AMR.* Undisputed that Entergy made the referenced determination but disputed as to the validity and significance of Entergy's determination. *Those other active electrical and I&C commodity groups include transformers. Rucker Decl. at ¶ 17.* Undisputed except that by including transformers in the category of "active electrical and I&C commodity groups" Entergy did not thereby make transformers active components.

28. *The NRC Staff published its Final SER for the IP2/IP3 LRA on August 12, 2009. Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3, Docket Nos. 50-247 and 50-286, Entergy Nuclear Operations, Inc. (Aug. 12, 2009). The Final SER concludes that Entergy "has adequately identified the electrical and I&C component commodity groups components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1)." Id. at 2-225. The Staff did not conclude that any IP2 or IP3 transformers are subject to AMR, or that an AMP is required for transformers, under 10 C.F.R. Part 54. Rucker Decl. at ¶ 18.* Undisputed.

F. <u>NRC Staff's Position on Whether Transformers Are Subject to AMR</u>

29. *In a September 19, 1997 letter signed by the Director of the NRC's License Renewal Project Directorate, the NRC Staff recommended revising Appendix B of NEI 95-10 to indicate that transformers "do not require an aging management review." In reaching this conclusion, the Staff considered the discussion of active and passive components and structures in the Statement of Consideration ("SOC") accompanying the 1995 revisions to the License Renewal Rule. Craig Decl. at ¶¶ 25-26; Letter from Christopher Grimes, Director, License Renewal Project Directorate, NRC, to Douglas J. Walters, NEI, Determination of Aging*

Management Review for Electrical Components (Sept. 19, 1997) ("NRC 1997 Letter"). Disputed to the extent these statements do not fully describe all relevant portions of the summarized document, and disputed to the extent the statement is intended to reflect that the Staff gave appropriate consideration to the discussion of active and passive components in the 1995 Statement of Consideration.

30. *In particular, the NRC Staff's 1997 Letter states:*

> *Based on the considerable discussion provided in the rule and SOC, the staff compared [transformers] . . . with the examples explicitly provided in the rule in terms of how the performance of their intended functions would be achieved and whether aging degradation of these components would be readily monitored using currently available techniques, in a similar way by which the examples in the rule (circuit breakers, relays, switches, etc.) would be monitored.*

Craig Decl. at ¶ 26; NRC 1997 Letter at 2. Undisputed that the NRC staff made the quoted statements, but disputed as to the validity and significance of the NRC staff's conclusions.

31. *The NRC Staff concluded in the 1997 Letter that "[t]ransformers perform their intended function through a change in state similar to switchgear, power supplies, battery chargers, and power inverters, which have been excluded in §54.21(a)(1)(i) from an aging management review," and that "[a]ny degradation of the transformer's ability to perform its intended function is readily monitorable by a change in the electrical performance of the transformer and the associated circuits." Craig Decl. at ¶ 26; NRC 1997 Letter at 2.* Undisputed as to the accuracy of the quotation, but disputed as to the validity of the statements in the quotation.

32. *NEI revised Appendix B to NEI 95-10 to incorporate the recommendation of the Staff that transformers be excluded from AMR, because they do not qualify as passive, long-lived*

structures or components. Undisputed but no longer relevant since the NEI classification of transformers was based on the following reasoning:

> Transformers perform their intended function through a change in state by stepping down voltage from a higher to a lower value, stepping up voltage to a higher value, or providing isolation to a load. Transformers perform their intended function through a change in state similar to switchgear, power supplies, battery chargers, and power inverters, which have been excluded in §54.21(a)(1)(i) from an aging management review. *Any degradation of the transformer's ability to perform its intended function is readily monitorable by a change in the electrical performance of the transformer and the associated circuits.* Trending electrical parameters measured during transformer surveillance and maintenance such as Doble test results, and advanced monitoring methods such as infrared thermography, and electrical circuit characterization and diagnosis provide a direct indication of the performance of the transformer. Therefore, transformers are not subject to an aging management review.

NEI 1995 at C-12 (emphasis added). The more recent studies by EPRI and IEEE (*see* Electrical Power Research Institute, Life Cycle Management Planning Sourcebooks, Volume 4: Large Power Transformers, Final Report, 1007422 (Mar. 2003), EPRI, Large Transformer End-of-Expected-Life Considerations and the Need for Planning [1013566], December 2006, and IEEE Power Engineering Society, IEEE Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformers (Apr. 27, 2007)) plus the findings of the NRC in its recent Information Notice demonstrate that merely conducting performance monitoring is no longer believed to be sufficient to detect potential failures of transformers. Blanch Decl. at ¶¶ 44-49, 52, 53. *The NRC Staff endorsed NEI 95-10 in Regulatory Guide 1.188. Craig Decl. at ¶ 27; Rucker Decl. at ¶¶ 14-15.* Undisputed as to the descriptions of NEI's and NRC Staff's actions but disputed as to the significance of such action and whether transformers are passive, long-lived components. Moreover, the proffered statement must be considered in light of the following statement in the Regulatory Guide 1.188 at 1, fn. 1:

> The U.S. Nuclear Regulatory Commission (NRC) issues regulatory guides to describe and make available to the public methods that the NRC staff considers acceptable for use in implementing specific parts of the agency's regulations, techniques that the staff uses in evaluating specific problems or postulated accidents, and data that the staff need in reviewing applications for permits and licenses. Regulatory guides are not substitutes for regulations, and compliance with them is not required. Methods and solutions that differ from those set forth in regulatory guides will be deemed acceptable if they provide a basis for the findings required for the issuance or continuance of a permit or license by the Commission.

Neither NEI's nor the NRC staff's opinion is dispositive on the question of whether transformers are passive or active components.

33. *The Staff has conveyed this position to the Commission and the Advisory Committee on Reactor Safeguards. Craig Decl. at ¶¶ 29-31.* Disputed. A single passing description of transformers as "active" in a document sent to the Commission does not mean the Staff has "conveyed" its position on this issue to the Commission or that the Staff asked the Commissioners to expressly and formally ratify this position. If the Staff intended to convey this position to the Commission or seek formal ratification from the Commission it should have highlighted the issue and explicitly asked the Commission to rule, rather than making a single incidental description in a document focused on other issues. *In SECY-01-0157, dated August 17, 2001, the Staff explicitly referred to the transformers as "active components" that "are not subject to the license renewal requirements." Craig Decl. at ¶¶ 30-31; SECY-01-0157, Rulemaking Issue, License Renewal Rulemaking (Aug. 17, 2001).* Undisputed that NRC staff made the quoted statement, but disputed as to the validity of the NRC Staff's conclusions.

34. *In a Staff Requirements Memorandum issued on September 5, 2001, the Commission*

concurred with the Staff recommendation that no additional changes to Part 54 be pursued at that time. Undisputed. *The Commission expressed no objection to the Staff's explicit characterization of transformers as "active components" that are not subject to AMR under Part 54. Craig Decl. at ¶ 32; Staff Requirements Memorandum, SECY-01-0157, License Renewal Rulemaking (Sept. 5, 2001), available at ADAMS Accession No. ML012480330.* Disputed because the Commission made no reference to the NRC staff's passing description of transformers as "active components," and the Commission made no reference to any part of the substance of the NRC Staff submittal other than to agree that no rule making was warranted. The State disputes whether the September 5, 2001 Staff Requirements Memorandum indicates a Commission determination that transformers are active components. Moreover, these statements are legal conclusions that are not supported by a competent expert.

35. *The NRC issued the first renewed operating licenses under Part 54, for Calvert Cliffs Units 1 and 2, on March 23, 2000.* Undisputed. *That application and every other license renewal application subsequently reviewed and approved by the NRC has reflected the determination that transformers are not subject to AMR under Part 54. Craig Decl. at ¶ 28, 34.* Undisputed that the renewed operating licenses that the NRC has issued to date have not required the licensee to include transformers in aging management, but the State disputes whether the NRC has made a determination that transformers are active components, and whether the renewed licenses that have been issued reflect any such NRC determination. Moreover, these statements are legal conclusions that are not supported by a competent expert. Whether the NRC has made a determination that transformers are active components, and whether the renewed licenses that have been issued reflect any such NRC determination, are

legal matters as to which no admissible affiant statement has been offered.

Dated: September 23, 2009
New York, New York

Respectfully submitted,

/s

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UNITED STATES
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

In re:	Docket Nos. 50-247-LR and 50-286-LR
License Renewal Application Submitted by Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc.	ASLBP No. 07-858-03-LR-BD01 DPR-26, DPR-64 September 23, 2009

DECLARATION OF JANICE A. DEAN

Pursuant to 28 U.S.C. § 1746, Janice A. Dean hereby declares as follows:

1. I am an Assistant Attorney General for the State of New York, counsel for petitioner-intervenor State of New York in this proceeding.

2. I make this Declaration in support of the State of New York's response to Entergy's motion for summary disposition and NRC Staff's answer.

3. Annexed hereto as Exhibit A is a true and correct copy of Letter, Malcolm H. Philips, Jr. and William A. Horin, Counsel to the Nuclear Utility Group on Equipment Qualification, to John C. Hoyle, Acting Secretary, United States Nuclear Regulatory Commission, *Re: Nuclear Power Plant License Renewal; Proposed Revisions 59 Fed. Reg. 46574* (September 9, 1994) (Dec. 8, 1994). The document's NRC PDR fiche number is 9412130158.

4. I declare under penalty of perjury that the foregoing is true and correct.

Executed on September 23, 2009.

Janice A. Dean

Janice A. Dean

Exhibit A

NUCLEAR UTILITY GROUP
ON EQUIPMENT QUALIFICATION

DOCKETED

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(17)

SUITE 800
1400 L STREET, N.W.
WASHINGTON, D.C. 20005-3502
TELEPHONE (202) 371-5700

December 8, 1994

DOCKET NUMBER
PROPOSED RULE PR 2,51 & 54
(59 FR 46574)

Mr. John C. Hoyle
Acting Secretary, U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Re: Nuclear Power Plant License Renewal; Proposed Revisions (59 Fed. Reg. 46574 (September 9, 1994))

Dear Mr. Hoyle:

I. Introduction

The Nuclear Utility Group on Equipment Qualification ("NUGEQ")[1] hereby submits the following comments on the Nuclear Regulatory Commission's ("NRC") proposed rule to revise its license renewal regulations at 10 C.F.R. Part 54.[2] The proposed rule is a significant improvement over the current Part 54 license renewal framework, and NUGEQ congratulates the NRC on its efforts. Nevertheless, the NUGEQ believes that clarification is warranted with regard to certain issues related to the interaction of the rule with environmental qualification of electrical equipment pursuant to 10 C.F.R. § 50.49. In particular, NUGEQ respectfully requests the NRC to:

- clarify the specific reference to equipment qualified pursuant to 10 C.F.R. § 50.49 in the license renewal scope definition;

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[1] The NUGEQ is comprised of 36 electric utilities in the United States and Canada, including NRC licensees authorized to construct and/or operate over 100 nuclear power reactors. The NUGEQ was formed in 1981 to address and monitor topics and issues related to equipment qualification, primarily with respect to the environmental qualification of electrical equipment pursuant to 10 C.F.R. §50.49.

[2] 59 Fed. Reg. 46574 (September 9, 1994).

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2 59FR46574 PDR

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- acknowledge that emerging technologies may permit condition monitoring of passive components (e.g., electrical cable) that would preclude the need for aging management reviews of that equipment; and

- clarify that the rule does not require an evaluation of time-limited aging analyses for qualified equipment that is changed out on a regular basis.

The primary thrust of these comments is to assure clarity in the Commission's direction regarding certain key elements of the license renewal rule as it applies to 10 C.F.R. § 50.49 equipment. The NUGEQ believes such clarity is important to avoid potential confusion in the future appli ation of the license renewal rule and to minimize licensees' imple entation costs.

In addition, NUGEQ strongly agrees with the NRC's determination that, with respect to non-safety related systems structures and components ("SSCs"), the license renewal review would not require consideration of "hypothetical failures that could result from system interdependencies that are not part of the current licensing bases and that have not been previously experienced..."[1]

Our detailed comments appear below. NUGEQ also supports the comments filed by the Nuclear Energy Institute ("NEI").

II. Discussion

A. Scope Of License Renewal Rule

The defined scope of the proposed license renewal rule, Proposed § 54.4, is divided into three categories. The third category, Subsection (a)(3) of Section 54.4, explicitly includes within the scope of the rule those SSCs:

> relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the

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[1] 59 Fed. Reg. at 46579-80.

> Commission's regulations for . . . environmental qualification (10 C.F.R. § 50.49).[4]

For the following reasons, the NUGEQ proposes that the Commission clarify the intent and effect of that provision.

The definition of scope in the NRC regulation governing environmental qualification of electrical equipment, 10 C.F.R. §50.49, is also divided into three categories (Subsections (b)(1)-(3)). Significantly, there is a direct parallel between the § 50.49 (b)(1) and (2) equipment scope definitions, and the Proposed § 54.4(a)(1) and (2) SSC scope definitions. A similar parallel does not exist between Proposed § 54.4 and the other provisions referenced in §54.4(a)(3).[5]

As a practical matter, therefore, the only purpose to be served by the third element of Proposed § 54.4, i.e., Subsection (a)(3), with respect to 50.49 equipment is to assure inclusion in the license renewal rule of § 50.49 components that were <u>not</u> already captured by Proposed § 54.4 (a)(1) and (2), <u>i.e.</u>, § 50.49 (b)(3) equipment.

Accordingly, to assure clarity and consistency between the respective regulatory schemes, NUGEQ recommends that the language of Proposed 54.4(a)(3) that concerns Section 50.49 be modified to reference <u>only</u> 50.49(b)(3). Absent such clarification, Proposed 54.4(a)(3) might be read to suggest that licensees are to review "safety analyses or plant evaluations" to reassess the entire scope of each plant's §50.49 equipment. In reality, the only §50.49 equipment that remains to be captured by Proposed Section 54.4(a)(3) is that equipment identified in § 50.49(b)(3).

In addition, even if the NRC does not clarify Proposed Section 54.4(a)(3) as requested above, NUGEQ proposes that the

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[4] Proposed 10 C.F.R. § 54.4(a)(3). This section also identifies as within the scope of the rule SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with fire protection (10 C.F.R. § 50.48), pressurized thermal shock (10 C.F.R. § 50.61), anticipated transient without scram (10 C.F.R. § 50.62), and station blackout (10 C.F.R. § 50.63).

[5] See footnote 4.

following language be added to the SOC of the final rule with respect to Section 54.4:

> *For purposes of Section 54.4, the scope of Section 50.49 equipment to be included within Section 54.4 is that equipment already identified by licensees under 10 C.F.R. §§ 50.49(b)(1)-(3). Licensees may rely upon their CLB listing of 10 C.F.R. § 50.49 equipment, as required by 10 C.F.R. § 50.49(d), for purposes of satisfying Section 54.4 with respect to equipment within the scope of Section 50.49.*

This clarification will provide further assurance, in addition to the above suggested revision to the regulation itself, that licensees will not be expected to conduct further evaluations or analyses to identify Section 50.49 equipment to be included within the Section 54.4.

B. <u>Long-Lived, Passive Components</u>

Proposed Section 54.21 directs that an aging management review be performed for passive, long-lived components. Proposed Section 54.21(a)(1)-(3). The Commission acknowledges, however, that a licensee may be able to show that a replacement program based on performance or condition for passive components can provide reasonable assurance that performance will be maintained throughout the extended license term.[6] NUGEQ requests that the Commission include in the final rule SOC an example of passive component condition monitoring capabilities that may ultimately be used in this context. Such a comment would be consistent with the Commission's discussion noted above in the proposed rule SOC with respect to licensees' use of site-specific justifications concerning passive components.[7]

Specifically, research regarding and development of condition monitoring techniques for electrical cable -- explicitly identified as a passive, long-lived component in Proposed § 54.21(a)(1)(i) -- is underway both in the United States (including

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[6] 59 Fed. Reg. at 46585.

[7] 59 Fed. Reg. at 46585.

Commission-sponsored research) and in Europe.[8] Accordingly, NUGEQ requests that the following language be included in the SOC discussion in the final rule concerning passive, long-lived components:

> ***Cable condition monitoring methodologies now being developed may support a licensee demonstration that a replacement program has been established based on performance or condition for electrical cables that will provide reasonable assurance of continued performance of their intended function throughout the period of extended operation.***

C. <u>Time-Limited Aging Analyses</u>

The proposed rule would require, as part of the technical application for license renewal, a licensee evaluation of time-limited aging analyses for SSCs within the scope of the license renewal rule.[9] In the SOC for the proposed rule, the NRC specifically included environmental qualification of electrical equipment among the types of time-limited aging analyses that would have to be addressed.[10] However, the proposed definition of time-limited aging analyses would exclude from consideration analyses that are not "based on explicit assumptions defined by the current operating term of the plant."[11] In this regard, the NRC noted that:

> time limited aging analyses based on an assumed period of plant operation short of the current operating term should be addressed within the

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[8] These research efforts were discussed during the November, 1993, EQ Workshop. The workshop results were published in May 1994. <u>See</u> "Workshop on Environmental Qualification of Electric Equipment," NUREG/CP-0135 (May 1994), Session C, Condition Monitoring.

[9] Proposed 10 C.F.R. § 54.21(c).

[10] 59 Fed. Reg. at 46586.

[11] Proposed 10 C.F.R. § 54.3.

original license and are of no concern for license renewal.[12]

The NUGEQ believes the Commission intended that equipment, including 10 C.F.R. § 50.49 equipment, that is replaced on a frequency that is less than the duration of the current operating license term would not be included in the time limited aging analysis evaluation.

However, the terms of the proposed rule could be misinterpreted. Where a § 50.49 component's qualified life is less than 40 years its replacement schedule could result in a qualified life for that equipment that extends beyond the current license term. For such equipment the "assumed period of plant operation" for the qualified life determination could be said to exceed (rather than be "short of"[13]) the "current operating term." For example, a component with a fifteen year qualified life would be replaced at year 15 and again at year 30. The qualified life at the second replacement would exceed the remaining operating term. A restrictive reading of the Proposed Rule and SOC could suggest that the existing time-limited aging analysis be evaluated. This certainly does not appear to be the Commission's intent when it proposed this particular exclusion from the time-limited aging analysis review.

NUGEQ requests that the NRC clarify this potential ambiguity by explicitly noting in the SOC that the time-limited aging analyses evaluation does not cover short-lived (i.e., less than 40 year qualified life) components under 10 C.F.R. § 50.49. This would also serve to clarify the Commission's intent with respect to time-limited aging analyses in other contexts. We suggest the following language be included in the final rule SOC:

> *For example, a component qualified pursuant to 10 C.F.R. § 50.49 with a qualified life of 15 years would be replaced in years 15 and 30 of operation. Because the duration of the qualified life (i.e., 15 years) is less than the duration of the current license term (e.g., 40 years), the supporting time-limited aging analysis would not require evaluation under Section 54.21(c). Such equipment may continue to be replaced at 15 year intervals throughout the new license term.*

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[12] 59 Fed. Reg. at 46586.

[13] Id.

D. <u>Consideration Of Hypothetical Failures</u>

The statement of considerations for the proposed rule makes clear that, with respect to non-safety related SSCs, the license renewal review would not require consideration of hypothetical failures that could result from system interdependencies, that are not part of the current licensing bases, and that have not been previously experienced.[14] NUGEQ commends the NRC's recognition of the potential difficulties that consideration of hypothetical failures could create for licensees. NUGEQ strongly supports the NRC's position on this matter.

We appreciate the opportunity to comment upon the license renewal proposed rule.

Respectfully submitted,

Malcolm H. Philips, Jr.
William A. Horin

Counsel to the
Nuclear Utility Group on
Equipment Qualification

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[14] 59 Fed. Reg. at 45579-80.

UNITED STATES
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

In re:	Docket Nos. 50-247-LR; 50-286-LR
License Renewal Application Submitted by Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc.	ASLBP No. 07-858-03-LR-BD01
	DPR-26, DPR-64
	September 23, 2009

RESPONSE OF THE STATE OF NEW YORK TO ENTERGY'S SUMMARY DISPOSITION MOTION AND NRC STAFF'S SUPPORTING ANSWER

TABLE OF CONTENTS

PRELIMINARY STATEMENT

The State of New York respectfully submits this response to Entergy's August 14, 2009, Motion for Summary Disposition of New York State's Contention 8 (Electrical Transformers) and NRC Staff's September 14, 2009 Answer in support of Entergy's motion. Because Entergy seeks here to improperly re-litigate an issue already addressed by the Board, because transformers are passive components for which an aging management review is required, and because trade association and NRC Staff memoranda and position papers are not binding, all of which the Board has acknowledged in admitting Contention 8, Entergy's motion should be denied.

BACKGROUND

Regulatory Background

The NRC's regulations require an applicant for license renewal to prepare an Integrated Plant Analysis which includes a list of those structures and components subject to an aging management review ("AMR"). 10 C.F.R. § 54.21(a)(1). The structures and components subject to an AMR include those "that perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties." 10 C.F.R. § 54.21(a)(1)(i). The regulation then offers a non-exclusive list of components which require an AMR; transformers are not on this list. *See id.* The Commission also concluded in its Statement of Considerations for its 1995 revisions to the license renewal regulations that "structures and components that perform active functions can be generically excluded from an aging management review on the basis of performance or condition-monitoring programs." 1995 Part 54 Revisions, 60 Fed. Reg. 22,461 at 22,477. Entergy seeks to fit transformers into this category of excluded components.

The State of New York's Contention 8

On November 30, 2007, the State of New York submitted its Notice of Intention to Participate and Petition to Intervene. In its Petition, the State argued that Entergy's License Renewal Application for Indian Point Units 2 and 3 violated 10 C.F.R. §§ 54.21(a) and 54.29 because it failed to include an aging management plan for each electrical transformer whose proper function is important for plant safety. *See* NYS Petition at 103-05.[1] The State, relying on the authority of its expert, Mr. Paul Blanch, argued that "transformers function without moving parts or without a change in configuration" or properties defined in 10 C.F.R. § 54.4(a)(1), (2), and (3). *See* Declaration of Paul Blanch (Nov. 28, 2007). The State further alleged that the failure to manage properly aging of electrical transformers may compromise: (1) the integrity of the reactor coolant pressure boundary; (2) the capability to shut down the reactor and maintain it in a safe shutdown condition; or (3) the capability to prevent or mitigate the consequences of accidents, which could result in potential offsite exposures comparable to those referred to in 10 C.F.R. §§ 50.34(a)(1), 50.67(b)(2), or 100.11. *See* New York State Reply in Support of Petition to Intervene (Feb. 22, 2008), at 58. The State additionally alleged that the failure to manage properly the aging of electrical transformers could result in loss of emergency power to the 480 volt safety equipment and 6.9kV busses, including all station blackout loads, and may result in accidents beyond the Design Basis Accidents causing exposures to the public exceeding 10 C.F.R. § 100 limits. *Id.*

The Board, observing that Contention 8 was supported by expert opinion, admitted Contention 8 over Entergy's objections. *See* Memorandum and Order (Ruling on Petitions to

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[1] The State's contention read: "The LRA For IP2 and IP3 Violates 10 C.F.R. §§ 54.21(a) And 54.29 Because It Fails To Include An Aging Management Plan For Each Electrical Transformer Whose Proper Function Is Important For Plant Safety."

Intervene and Requests for Hearing) (July 31, 2008). Entergy argued, unsuccessfully, that the State failed to provide sufficient factual foundation for the contention; that the contention was outside the scope of the proceeding because only passive components are within scope; and that the contention fails to establish a genuine dispute with the Applicant on a material issue of law or fact. *See* Answer of Entergy Nuclear Operations, Inc., Opposing New York State Notice Of Intention to Participate and Petition to Intervene (Jan. 22, 2008) ("Entergy Answer"). Entergy conceded that certain transformers, those that are safety-related or are necessary for compliance with 10 C.F.R. §§ 50.48 and 50.63, were within the scope of license renewal but that an aging management review was only required for passive components. Entergy Answer at 69-70. NRC Staff also opposed the contention's admission, arguing that Staff had taken the position in its own guidance that 10 C.F.R. § 54.21(a)(1)(i) does not require AMR for transformers. NRC Staff's Response To Petitions For Leave To Intervene Filed By (1) Connecticut Attorney General Richard Blumenthal, (2) Connecticut Residents Opposed To Relicensing Of Indian Point, and Nancy Burton, (3) Hudson River Sloop Clearwater, Inc., (4) The State Of New York, (5) Riverkeeper, Inc., (6) The Town Of Cortlandt, And (7) Westchester County (Jan. 22, 2008)("Staff Response"), at 45.

The Board's Order Admitting Contention 8

The Board admitted Contention 8 over Entergy's and NRC Staff's objections. Specifically, the Board observed that "[t]ransformers (necessary for compliance with 10 C.F.R. §§ 50.48 and 50.63) nominally perform their safety-related function without moving parts and without a change in configuration or properties. Accordingly, 10 C.F.R. § 54.21(a)(1) defines this component as a piece of equipment subject to AMR." Memorandum and Order (Ruling on Petitions to Intervene and Requests for Hearing) (July 31, 2008), at 44. The Board was not persuaded by Entergy's argument that industry guidance controls here, stating that such guidance has "no legal authority to supercede the plain language of the regulatory criteria that requires AMR for a structure or component that performs its safety functions without moving parts and without a change in configuration or properties." *Id.* The Board admitted the contention "to the extent that it questions the need for an AMP for safety-related electrical transformers that are required for compliance with 10 C.F.R. §§ 50.48 and 50.63" because "[n]either Entergy nor the NRC Staff has provided any legally binding justification to exclude transformers from AMR beyond an apparent similarity to other components that have been excluded by 10 C.F.R. § 54.21(a)(1)(i), nor, as mentioned, has either party provided any explanation on how a transformer changes its configuration or properties in performing its functions." *Id.*

Entergy's Motion for Summary Disposition

Entergy's motion for summary disposition raises these same objections again, this time with expert support which Entergy's opposition to Contention 8 lacked in the first instance but which, while more detailed than Entergy's previous arguments, provides no new analysis or argument not previously advanced by Entergy. With only minor exceptions, the bulk of these expert declarations are inadmissible as evidence and thus do not meet the criteria for a summary disposition motion because they consist of (1) legal opinions offered by non-lawyers or (2) summaries of the contents of documents that contain regulations or explanations of regulations, rather than merely attaching the documents and allowing them to speak for themselves. Entergy argues that the record shows no genuine issue of material fact, and that the State has not provided information or analysis to support the State's position that transformers function "without moving parts or without a change in configuration or properties" such that they fall under Part 54's Aging Management Program requirements. Primarily, Entergy argues that transformers undergo a "change in state" (or a "change in configuration") when voltage travels through the transformer. For the reasons outlined below, Entergy's motion must fail, as it rests on a fundamental misunderstanding of the nature of transformer operation and, at best, illustrates the specific nature, rather than the absence, of a factual dispute – *i.e.,* does a transformer change when current that passes through the transformer changes?

STANDARD OF REVIEW

The regulations at 10 C.F.R. § 2.1205 govern summary disposition motions, and require the Board to apply the summary disposition standard set forth in Subpart G. 10 C.F.R. § 2.1205(c). In general, the Commission applies the same standard that the federal courts apply when ruling on motions for summary judgment under Rule 56 of the Federal Rules of Civil Procedure. *See In re Entergy Nuclear Vt. Yankee L.L.C.*, Docket No. 50-271-OLA; ASLBP No. 04-832-02-OLA, 63 N.R.C. 116 (Jan. 31, 2006), citing *Advanced Medical Systems. Inc.* (One Factory Row, Geneva, Ohio 44041), CLI-93-22; 38 N.R.C. 98, 102 (1993). Under the Subpart G standard, summary disposition is proper "if the filings in the proceeding, depositions, answers to interrogatories, and admissions on file, together with the statements of the parties and the affidavits, if any, show that there is no genuine issue as to any material fact and that the moving party is entitled to a decision as a matter of law." 10 C.F.R. § 2.710(d)(2). Summary disposition "is not a tool for trying to convince a Licensing Board to decide, on written submissions, genuine issues of material fact that warrant resolution at a hearing." *In re Entergy Nuclear Vt. Yankee L.L.C.,* 63 NRC at 121, *quoting Private Fuel Storage, L.L.C.* (Independent Spent Fuel Storage Installation), LBP-01-39, 54 N.R.C. 497, 509 (2001).

The moving party bears the burden of demonstrating that there is no genuine issue as to any material fact. 10 C.F.R. § 2.325; *In re Entergy Nuclear Vt. Yankee L.L.C., quoting Private*

Fuel Storage, L.L.C., 63 NRC at 121. Any doubt as to the existence of a genuine issue of material fact is resolved against the moving party. *Id.*, citing *Advanced Medical*, CLI-93-22, 38 N.R.C. at 102. "Because the burden is on the moving party, the Board must examine the record in the light most favorable to the non-moving party and give the non-moving party the benefit of all favorable inferences that can be drawn from the evidence." *Id.* When conflicting expert opinions are involved, summary disposition is rarely appropriate. *In re Entergy Nuclear Vt. Yankee L.L.C., quoting Private Fuel Storage, L.L.C.*, 63 N.R.C. at 122, citing *Phillips v. Cohen*, 400 F.3d 388, 399 (6th Cir. 2005)("competing expert opinions present the 'classic battle of the experts' and it [is] up to [the finder of fact] to evaluate what weight and credibility each expert opinion deserves").

ARGUMENT

POINT I

LAW OF THE CASE BARS RELITIGATION OF THIS ISSUE

Relitigation of this issue, which as discussed above has already been decided by the Board, is barred by the law of the case doctrine. "The form in which a contention is admitted is a decision of the licensing board and becomes part of the law of the case. Other materials from the record may be used to interpret the admitted contention but not to challenge its admissibility." *In re Cleveland Electric Illuminating Company*, et al. (Perry Nuclear Power Plant, Units 1 & 2), 17 N.R.C. 501 (ASLB, 1983). "The repose doctrine of law of the case acts to bar relitigation of the same issue in subsequent stages of the same proceeding." *In re Ohio Edison Co.* (Perry Nuclear Power Plant, Unit 1, Facility Operating License No. NPF-58), 36 N.R.C. 269 (N.R.C. 1992), citing *Arizona v. California,* 460 U.S. 605, 618 (1983). The law of the case doctrine is "a salutary rule of policy and practice, grounded in important considerations related to stability in the decision[-]making process, predictability of results, proper working relationships between trial and appellate courts, and judicial economy." *In re Hydro Res., Inc.*, 63 N.R.C. 483, 489 (N.R.C. 2006), citing *United States v. Rivera-Martinez,* 931 F.2d 148, 151 (1st Cir.), *cert. denied,* 502 U.S. 862 (1991).

A. The Board's July 31, 2008 decision requiring resolution of this issue at a hearing is now law of the case

The Board concluded in its contention admissibility decision that "[t]ransformers (necessary for compliance with 10 C.F.R. §§ 50.48 and 50.63) nominally perform their safety-related function without moving parts and without a change in configuration or properties. Accordingly, 10 C.F.R. § 54.21(a)(1) defines this component as a piece of equipment subject to AMR." Memorandum and Order (July 31, 2008), at 44. The Board rendered this decision after considering Entergy's position, raised in its response to the State's contention at the contention admissibility stage, that only certain transformers were within the scope of license renewal and that its transformers were exempt from AMR requirements because they are active components. Entergy Answer at 69-70. Entergy has, in essence, made the same arguments here in the context of a motion for summary disposition;[2] the Board did not find Entergy's arguments persuasive then, and the Board's decision to send this issue to a hearing for resolution is now the law of the case.

As the Commission stated in *In re Hydrological Resources, Inc.*, "[a] prior decision should be followed unless: (1) the decision is clearly erroneous and its enforcement would work a manifest injustice, (2) intervening controlling authority makes reconsideration appropriate, or

[2] Even if it is proper to relitigate the issue of whether transformers are active or passive, Entergy, by offering expert opinions to challenge the expert opinion of New York State's expert and the previous holding of the Board, has, at most, simply demonstrated that there is a factual issue that requires resolution at a hearing.

(3) substantially different evidence was adduced at a subsequent trial." *In re Hydro Res., Inc.*, 63 N.R.C. at 489, *quoting Rainbow Magazine, Inc. v. Unified Capital Corp.*, 77 F.3d 278, 281 (9th Cir. 1996). Entergy has illustrated the presence of none of these factors: it points to no "manifest injustice" that would result from the consideration of this issue at a hearing; it cites no intervening controlling authority (indeed, it cites no adjudicatory authority at all for its argument); and no subsequent trial has taken place at which contrary evidence was adduced. Although application of "the law of the case doctrine" is a matter of discretion, and the Board certainly retains the discretion to depart from its previous decision when its "declared law is wrong and would work an injustice" (*see In re Public Service Company Of Indiana, Inc.* (Marble Hill Nuclear Generating Station, Units 1 and 2), 8 N.R.C. 253 (ASLAB, 1978)), no such risk of injustice is present here. To the contrary, as no ASLB panel has yet addressed squarely the issue of whether transformers require an aging management plan, it is in the interests of present and future intervenors and applicants to seek full resolution of this issue, at a hearing, at this time.

B. Entergy failed to file a timely motion for reconsideration of the Board's July 31, 2008 decision and cannot do so here

As the ASLB panel stated in *Georgia Power Company, et. al.*, "challenges to [Board] orders must be made promptly, through a motion for reconsideration filed no later than 10 days after issuance of the order (or sooner if the order takes effect more quickly). An unchallenged order becomes the law of the case and cannot be challenged subsequently." *In re Georgia Power Company, et. al. (Vogtle Electric Generating Plant, Units 1 and 2)*, 39 N.R.C. 257 (N.R.C. 1994). Entergy did not file a motion for reconsideration of the portion of the Board's July 31, 2008 contention admissibility decision that admitted New York State Contention 8, and thus cannot seek relitigation of the admission of that contention here. *See also In re Cleveland Electric Illuminating Company*, 17 N.R.C. 501 ("no party may challenge the precedential authority of [a Board] decision other than in a timely motion for reconsideration. Any other principle would leave the considered orders of this Board without effect and would make of this case a leaf endlessly turning in the wind, without course or direction.").[3] Despite this prohibition, the effect of Entergy's and NRC Staff's is to seek relitigation of issues previously decided. Much of the filings plow the same field again (*e.g.*, NEI 95-10 and the 1997 Grimes letter). The Board has already reviewed written submissions and oral argument on these points, and Entergy and Staff have not presented a compelling explanation why they should be permitted to have a second opportunity to press their arguments.

POINT II

ENTERGY'S MOTION MISCONSTRUES BOTH HOW TRANSFORMERS FUNCTION AND WHAT KIND OF COMPONENTS THE COMMISSION INTENDED TO BE SUBJECT TO AGING MANAGEMENT REVIEW

The State's expert put forward, to the satisfaction of the Board, sufficient information concerning the existence of a genuine issue of material fact to warrant adjudication at a hearing involving full exploration of the evidence: Are transformers passive systems, *i.e.*, do they function without moving parts and without a change in configuration or properties, or are they active and not subject to AMR? Entergy's motion, and the expert affidavits submitted in support of its motion, at best illustrate the factual dispute surrounding transformers and do not resolve the issue in Entergy's favor under 10 C.F.R. § 2.1205.

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[3] The risk also exists that if the same issue previously resolved by a Board is able to be slightly repackaged as a motion for summary disposition and no relitigation bar is imposed, parties may continuously represent essentially the same argument to the Boards once issues have been resolved (the "floodgate" problem).

A. Transformers do not change configuration, properties, or state

The State submits that Judge Wardwell pinpointed the nature of this dispute when he stated at oral argument that "The transformer doesn't change its state ... It's the electricity that changes state. And isn't it here that it's the device which we're considering, the component that we're considering, and it's a change in state of that component, not a change in state of some material coming in and out of it, like water into and out of a pump, because you change the state of water coming into and out of a pump, moving it faster." Tr. 213:23-24, 214:1-8 (Mar. 10, 2009). The panel properly acknowledged a factual dispute on this issue, as the State's expert raised a challenge to Staff's interpretation of § 54.21 and the factual nature of a transformer. *See* Tr. 214:15-18 ("But isn't it a valid challenge to [Staff's position] to determine at a hearing whether or not [Staff's] interpretation carries the day or not?"). Nothing in Entergy's expert affidavits changes this dispute: Entergy's experts and Staff interpret the regulations such that transformers are active; the State's expert interprets the regulations such that transformers are passive.

Indeed, if Staff and Entergy's interpretation of "changing state" carried the day, pipes, containment domes, electrical cables (which become heated when energized and can cause some energy loss as electricity is passed through them), to name only a few, would be considered active components because things inside them change. *See* September 22, 2009 Declaration of Paul Blanch ("Blanch Decl."), at ¶¶ 25-32 (analyzing similarities between transformers and components listed as included within § 54.21(a)(1)(i)). Taken to its logical conclusion, the Entergy and Staff position would eliminate most, if not all, of Part 54. The State submits that the Commission did not intend such a reading of § 54.21.

Counsel for Entergy indicated at oral argument that Entergy considers transformers active because the Staff puts them "in the same genre as power supplies" but noted that 10 C.F.R. § 54.21 does not explicitly reference transformers. Tr. 198:17 (Mar. 10, 2009). When pressed by the Board to locate the reference in 10 C.F.R. § 54.21 that excludes transformers, counsel for Entergy repeatedly referred the Board back to industry guidance (Tr. 198-200), which, as discussed below, is not binding.

In the attached Declaration, Mr. Paul Blanch establishes the fundamental facts that govern the issue raised by Entergy – facts which are actually not contradicted by Entergy or its experts. First, transformers have no moving parts. Blanch Decl., ¶¶ 17, 32. Second, transformers typically contain two insulated wires that are wrapped or coiled around form called a "core" that is frequently made of iron or metal alloys. *Id.*, ¶ 16. Third, a transformer itself does not change when it is in operation, nor does a transformer contain any moving parts for its basic function. *Id.*, ¶¶ 17, 32, 33. Fourth, the current flowing through the transformer does change as a result of the operation of the transformer. *Id.*, ¶¶ 17, 32, 33. Fifth, this change occurs because a magnetic field, created by the current flowing through the primary coil in the transformer causes a current to be generated in the second coil. *Id.*, ¶ 17. In addition, Mr. Blanch provides references to text books and an IEEE consensus definition that describe transformers as passive, static, and having no moving parts. *Id.*, ¶ 18.

The heart of the factual dispute here is Entergy's experts' assertion that the current itself and the magnetic field are components of the transformer and thus, because they change, the transformer changes. Entergy asserts, based on this claim, that therefore transformers are active components. However, as the Blanch Declaration demonstrates, the electric current is no more a part of the transformer than is the water in a hose a part of the hose, or the water in a steam generator a part of the steam generator, or the electricity flowing in a cable a part of the cable. Blanch Decl., ¶ 40; *see also id.* ¶¶ 26-31. In addition, several leading authorities on electrical components, including IEEE, define a transformer as a "passive" or "static" component. *See, e.g.*, Harlow, Electric Power Transformer Engineering, page 2-1 (2d Edition) CRC Press (2007) ISBN 0-8493-9186-5 (referencing ANSI / IEEE); Harlow, Electric Power Transformer Engineering, page 2-1, CRC Press (2004) ISBN 0-8493-1704-5; IEEE Standard Dictionary of Electrical and Electronic Terms, IEEE Std 100-1996 (6th Edition), page 1131, ISBN 1-55937-833-6 (1996). Moreover, Mr. Blanch disputes Entergy's experts' characterization of the adequacy of performance monitoring; Mr. Blanch's declaration explains, with references to EPRI, IEEE, and Sandia publications, that "current monitoring procedures for detecting the performance of transformers, such as those in use at Indian Point, are not adequate to detect, in advance of failure, all of the aging defects and degradation phenomena in transformers." Blanch Decl., ¶ 52. In short, the transformer is a passive component for which aging management review is required under 10 C.F.R. § 54.21(a)(1)(i).

B. The Commission intends that components that do not themselves change configuration, properties, or state (even if things that pass through them do change) be subject to aging management review

This plain reading of the regulations in light of the well-accepted understanding of the nature of transformers and how they operate is consistent with the Commission's Statement of Considerations regarding its license renewal regulations. When the current license renewal regulations were adopted in 1995, the Commission asserted that "mitigation of the detrimental effects of aging resulting from operation beyond the initial license term should be the focus for license renewal." Statement of Considerations, 60 Fed. Reg. 22,461, 22,464 (May 8, 1995) ("SOC"). The Commission also emphasized that in interpreting the scope of issues to be considered during a license renewal review, absent clear and convincing evidence that a system or component was to be excluded from such review, it should be considered as subject to review:

> As the commenter suggested, the Commission did consider further limiting the scope of license renewal to certain issues in a plant's design that were specifically based on a time period bounded by the current license term (40 years). As a result, the Commission explicitly identified the need to review time-limited aging analyses and incorporated this requirement into the final rule. However, as discussed in Section III.d and III.f of this SOC, the Commission determined that, at this time, there was not an adequate basis to generically exclude passive, long-lived structures and components from an aging management review. Therefore, the Commission believes it is inappropriate to further reduce the systems, structures, and components within the scope of license renewal.

SOC, 60 Fed. Reg. at 22,468.

In determining what systems and components would be subject to aging management review, the Commission was careful to draw a distinction between passive and active components and only the former, provided they are safety-related, are subject to aging management review. 60 Fed. Reg. at 22,477. The language adopted by the Commission to draw the line between passive and active components appears in 10 C.F.R. § 54.21(a)(1)(i), which declares that aging management review is required for systems and components "that perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties." Since it is not disputed that there are no moving parts in the transformers that are the subject of New York State Contention 8, the focus in this pleading is on the phrase "without a change in configuration or properties." The SOC emphasizes that in determining whether a component operates "without a change in configuration or properties" it is the component itself that is the focus of the inquiry, not the material that may flow through the component, such as steam, water or electricity. Thus, for example, the Commission makes clear that internal parts that move are exempt from aging management but not the housing of the component if it is part of the pressure boundary of the containment:

> the Commission determined that structures and components that perform active functions are not subject to an aging management review (e.g., pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies). However, pressure-retaining boundaries (e.g., pump casings, valve bodies, fluid system piping) and structural supports (e.g., diesel generator structural supports) that are necessary for the structure or component to perform its intended function meet the description of passive, and will be subject to an aging management review.

SOC, 60 Fed. Reg. at 22,477.

Entergy's analysis of transformers demonstrates a fundamental misunderstanding of the manner in which transformers function. As the preceding discussion demonstrates, transformers do not change their own configuration or properties and do not change their state. Rather, like pipes and electrical cables, transformers remain unchanged while allowing or facilitating the change of water or electricity that pass through them and belong under the aging management review.

The Commission also found that passive components without moving parts or a change in configuration or properties are components which are not readily monitored to detect degradation:

> passive structures and components for which aging degradation is not readily monitored are those that perform an intended function without moving parts or without a change in configuration or properties. For example, a pump or valve has moving parts, an electrical relay can change its configuration, and a battery changes its electrolyte properties when discharging. Therefore, the performance or condition of these components is readily monitored and would not be captured by this description. Further, the

> Commission has concluded that "a change in configuration or properties" should be interpreted to include "a change in state," which is a term sometimes found in the literature relating to "passive." For example, a transistor can "change its state" and therefore would not be screened in under this description.

Id.

When the Nuclear Utility Group on Equipment Qualification sought to have electrical cables excluded from the blanket definition of passive components because, it asserted, means to monitor the performance of cables were being developed and might obviate the need for aging management review (*see* Letter from Malcolm Philips and William Horan to the Secretary of the Commission dated December 8, 1994 at 2-4 (PDR fiche 9412130158)),[4] the Commission rejected the Group's request, emphasizing that the focus of its aging management concerns was not operational monitoring but rather monitoring of the degradation of the condition of the equipment to function in the future:

> The commenter stated that the only aging effects of cables are shorting and loss of continuity, and for cables not in a harsh environment, these effects would be immediately detected during normal operation or functional testing. The Commission considers the examples of electrical components (e.g., electrical cables, connections, and electrical penetrations) listed in 10 CFR 54.21(a)(1)(i) and Section III.f(i)(a) of the SOC to be properly categorized as "passive" because they perform their intended function without moving parts or without a change in configuration or properties and the effects of aging degradation for these components are not readily monitorable. The Commission also believes that this categorization is not premature as stated by the commenter. The Commission disagrees with the commenter's assertion that the aging effects of cable make it easy to monitor functional degradation. Although there have been significant advances in this area, there is no single method or combination of methods that can provide the necessary information about the condition of electrical cable currently in service regarding the extent of aging degradation or remaining qualified life.

[4] A copy of this document is attached to the declaration of Assistant Attorney General Janice Dean that accompanies this response.

> Degradation due to aging of electrical cables caused by elevated temperature and radiation can cause embrittlement in the form of cracking of insulation and jacket materials. The cracks degrade the electrical properties of the insulation materials. The major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions. Because these components are relied on to remain functional during and following design-basis events (including conditions of normal operation) and there are currently no known effective methods for continuous monitoring of cable systems, these examples of passive electrical components subject to an aging management review will remain in 10 CFR 54.21(a)(1)(i) and Section III f(i)(a) of the SOC.

SOC, 60 Fed. Reg at 22,477-78. Thus, the Commission made clear that passive components need to be subjected to aging management review because they may have, as do transformers, constituent parts which can degrade without affecting the current performance of the component but which can make the component vulnerable to failure in the future.

This concern that operational monitoring is not sufficient to assure that passive components will not malfunction has been heightened by the recent revelation by the NRC Staff that in at least 6 instances in the last two years failures have occurred in large transformers (including one at Indian Point 3) that, until they occurred, were not detected by monitoring methods in use at the reactors. July 7, 2009 NRC Information Notice 2009-10: Transformer Failures—Recent Operating Experience (ML090540218); *see* Blanch Decl. at ¶ 44. While the transformers involved were generally not safety related, the failures prompted the NRC Staff to observe:

> For several years, available industry operating experience has indicated an increasing trend in transformer failures, and has provided recommendations to reduce the chances of failure. Improved preventive maintenance and monitoring practices have helped to identify some problems before they developed to the point of failure, but the number of large transformers events has not decreased and in fact continues to rise.

Id. at 1. The NRC Staff further concluded, after its investigation, that:

> A relatively high incidence of transformer failures has occurred in the last few years, the majority of which could have been avoided had the licensee fully evaluated and effectively implemented corrective actions and recommendations identified in industry operating experience. These corrective actions included a more effective maintenance program and a more proactive approach to addressing abnormal indications.

Id. at 2. This recent Information Notice casts substantial doubt on the effectiveness of the monitoring programs to which Entergy makes reference in its Summary Disposition Motion (*see* Rucker Declaration at §§ 19-21) and provides a substantial basis for the proposition that transformers require an aging management review as part of the consideration of the license renewal application for Indian Point Units 2 and 3.[5] *See also* Blanch Decl. at ¶ 52 (discussing Rucker Declaration).

The ineffectiveness of the kind of performance monitoring programs relied upon by Entergy in its Motion is apparent from the analysis contained in the accompanying declaration of Mr. Paul Blanch. Mr. Blanch states that with the passage of time transformers age and can experience failure. He provides examples of some types of aging degradation mechanisms for transformers: the insulation can deteriorate, internal shorts could develop, moisture can collect

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[5] It is clear from Entergy's Statement of Material Facts that its programs for maintaining the integrity of transformers depends exclusively on monitoring performance and do not address the degradation of portions of the transformer which can lead to failure in the future but do not currently impact performance. *See* Entergy Statement of Material Facts at § 11 ("The data and information from such tests and *performance* monitoring programs are analyzed and trended to detect potential degradation of transformer *performance* (e.g., a change in the electrical performance of the transformer or the associated circuits).") (emphasis added). To being with, such performance monitoring does not appear to extend to all transformers. Moreover, this kind of myopic view of aging management is apparently one of the principal causes of unanticipated transformer failures detailed in the recent IN. As discussed below, EPRI and IEEE reports find a similar problem and focus on *condition* monitoring and not only performance monitoring. Those reports also identify aging management analysis, surveillance, and inspection techniques for transformers.

in the components, or connections can become loose; also, there could be a loss of coolant, an accumulation of oil, dirt, or salt spray, or corrosion. Blanch Decl. at ¶ 50. Moreover, aging degradation of some constituent parts of transformers is not detected by performance monitoring. Blanch Decl. at ¶ 51. Thus, just as in the case of other passive components, such as electrical cables, for which the Nuclear Utility Group on Equipment Qualification sought special status, safety-related transformers must be subjected to an aging management review because "there is no single method or combination of methods that can provide the necessary information about the condition of [transformers] currently in service regarding the extent of aging degradation or remaining qualified life." SOC, 60 Fed. Reg. at 22,477 (bracket added).

Recent EPRI and IEEE reports reflect recognition of the significance of transformer failures. *See* Blanch Decl. at ¶¶ 45-47. In 2003, the Electric Power Research Institute identified a growing problem with failures in large transformers and proposed a wide range of maintenance programs that it recommended be implemented by nuclear utilities to address these problems, including the problem of aging degradation of transformers. *See* Life Cycle Management Planning Sourcebooks, Volume 4: Large Power Transformers 1007422 Final Report (Mar. 2003) at 4-1 to 4-6, 4-17 and 6-2 to 6-13. In Chapter 7 of that report EPRI accepts the proposition that transformers are subject to aging management programs which, if properly implemented, can substantially improve the operating life of the transformer as well as improve plant safety. *See id.* at 7-2, where in discussing the option of operating a plant for 60 years under license renewal EPRI offers aging management of transformers as part of one of the alternatives: "[Life Cycle Management] Plan Alternative 2A: A rigorous preparation for license renewal with an aggressive aging management program, system performance enhancements, and timely component replacements or upgrades. This LCM plan recommends timely replacement of like-for-like components such as pumps, fans, motors, level and temperature indicators, etc." In a 2006 EPRI document, EPRI again describes the causes of transformer failures and advocates the use of condition monitoring and not just performance monitoring, to detect failure potential before failures occur. Plant Support Engineering: Large Transformer End-of-Expected-Life Considerations and the Need for Planning – 1013566 - Final Report (Dec. 2006), at 2-3 to 2-10, 3-1 to 3-5. *See also* SAND93-7068, May 1994, Aging Management Guideline For Commercial Nuclear Power Plants – Power And Distribution Transformers at 1-3 to 1-7, 4-7 to 4-21 and 5-22 (identifying transformer failure modes and monitoring programs needed to prevent such failures); IEEE Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformers (IEEE Std C57.140-2006) at 11-15 (listing failure modes of transformers and methods for detecting these failures before they occur).

Notwithstanding NRC, EPRI, and IEEE concern with aging problems with transformers, the growing evidence of transformer failures since at least 1995, and the existence of condition monitoring aging management techniques and programs that can provide considerable enhancement to the integrity and reliability of transformers, Entergy continues to insist that it should not have to perform an aging management review of its transformers and that it should not have to implement special programs to address aging problems in its transformers for its reactors to be allowed to continue to operate for an additional twenty years. It is to deal with precisely the kinds of problems presented by passive components like transformers that the NRC requires that such components be subjected to an aging management review. It is apparent from Entergy's actions in this proceeding that absent action by this Board, Entergy will not implement aging management programs like those recommended by EPRI, to attempt to assure the reliability of its safety related transformers during extended operation; its experts believe aging management is not necessary for transformers and that transformers are exempted from aging management review because they are active components.

If the assertion by Entergy's experts (that because the current flowing through the transformer and the magnetic field created by that current changes, the transformer itself changes) has any evidentiary weight, which New York State contends it does not, then the most Entergy's motion has done is set up a "classic battle of the experts" mandating denial of Entergy's motion and exploration of this issue at a hearing. *See In the Matter of Entergy Nuclear Vermont Yankee, L.L.C., And Entergy Nuclear Operations, Inc.* (Vermont Yankee Nuclear Power Station), Docket No. 50-271-LR, 2007 NRC LEXIS 90 (Aug. 10, 2007).

POINT III

LONG-STANDING COMMISSION PRECEDENT MAKES CLEAR THAT INDUSTRY GUIDANCE AND NRC STAFF POSITIONS ARE NOT BINDING

A. The question of whether transformers are active or passive is an issue of first impression for any ASLB

Entergy argues that the Staff's "long-standing" interpretation of 10 C.F.R. § 54.21 (a)(1)(i) confirms that transformers are properly excluded from AMR. Similarly, Entergy argues that "the Staff has consistently applied this position in every one of its approvals of a license renewal application since the very first application" and that "[e]very subsequent LRA approved by the NRC similarly has concluded that transformers are not subject to AMR under 10 C.F.R. Part 54." Entergy Br. at 28. But the issue is one of first impression for any ASLB; the State can find no evidence that an intervenor has ever raised the issue of whether transformers are active or passive for the purposes of an AMR. Thus, Staff's "long-standing" position on this issue has essentially gone unchallenged.[6]

B. NRC has consistently rejected the view that Staff or industry guidance is binding on the ASLB in cases where those positions are challenged by an intervenor

In other proceedings both Entergy and Staff have argued, against an apparent attempt by an intervenor to frame a contention on the basis of a failure to comply with a Staff guidance document, that such documents are merely advisory and compliance with them is not required. *See* Entergy's Answer to Vermont Department of Public Service Notice Of Intention To Participate And Petition To Intervene, *In the Matter of Entergy Nuclear Vermont Yankee, LLC and Entergy* (Vermont Yankee Nuclear Power Station), Docket No. 50-271, ASLBP No. 04-832-02-OLA (Sept 29, 2004), ML042820100, at 16; NRC Staff Answer To Vermont Department Of Public Service Notice Of Intention To Participate And Petition To Intervene, *In the Matter of Entergy Nuclear Vermont Yankee, LLC and Entergy* (Vermont Yankee Nuclear Power Station), Docket No. 50-271, ASLBP No. 04-832-02-OLA (Sept. 29, 2004) at 12, ML042780558, citing

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6 Entergy argues that the Commission has tacitly accepted the NRC staff's position that transformers are active devices and thus do not require aging management. *See* Entergy Motion at 28 n.162. The basis for Entergy's assertion is a passing NRC staff reference which cannot properly be laden with the meaning Entergy seeks to apply to it. In SECY-01-0157, an NRC staff member acknowledged that one reactor shutdown was caused by the failure of a passive component and that "other shutdowns were attributed to the failure of active components, such as transformers, solenoid valves, and circuit breakers." SECY-01-0157 (Aug. 17, 2001) (Rulemaking Issue, Negative Consent), ML012200365, at 3. This passing description was the document's only reference to transformers. Neither the passive-active distinction of components nor the role of transformers was the focus of the incoming rulemaking requests or the responsive SECY document. Instead, the SECY document recommended that the Commission reject certain rulemaking requests that were unrelated to transformers. Subsequently, in a one sentence SRM-SECY-01-0157 issued September 5, 2001, the Commission stated "the Commission has not objected to the staff's proposal that rulemaking to change 10 CFR Part 54 need not be pursued at this time." SRM-SECY-01-0157 (Sept. 5, 2001), ML012480330. The Commission's one-sentence decision hardly constitutes an affirmative acceptance of all the casual references in the Staff paper.

Long Island Lighting Co. (Shoreham Nuclear Power Station, Unit 1), LBP-91-35, 34 N.R.C. 163, 179 (1991).

The Commission has made this principle abundantly clear.

> Safety Guides (and the newer Regulatory Guides) merely set forth methods acceptable *to the regulatory staff* of implementing specific parts of Commission regulations. While they are entitled to considerable *prima facie* weight because of the important day-to-day responsibilities of the Regulatory Staff in effectuating Commission policy, these guides do not themselves have the force of regulations.

In the Matter of Vermont Yankee Nuclear Power Corporation (Vermont Yankee Nuclear Power Station), 8 A.E.C. 809, 811 (emphasis in original). *See also In the Matter of Philadelphia Electric Company* (Limerick Generating Station, Units 1 and 2), 22 N.R.C. 681, 737 (ASLAB, 1985)("Regulatory guides and the like do not prescribe regulatory requirements. In general, they are 'treated simply as evidence of legitimate means for complying with regulatory requirements, and the staff is required to demonstrate the validity of its guidance if it is called into question during the course of litigation.'"); *In the Matter of Duke Power Company* (Catawba Nuclear Station, Units 1 and 2), 4 N.R.C. 397, 416 (ASLAB, 1976) (footnote omitted)(stating that a staff working paper is "drafted to be sure by Commission employees" but "has been neither adopted nor sanctioned by the Commission itself and does not represent (or purport to represent) current Commission policy"); *In the Matter of Southern California Edison Company, et al.* (San Onofre Nuclear Generating Station, Units 2 and 3), 1 N.R.C. 383, 399 (ASLAB, 1975)("the staff is but one of the parties to this licensing proceeding, and … the positions which it may take are in no way binding upon us. The boards have independent responsibilities to fulfill, and the actions of the staff cannot compel a board to adopt a particular position.").

Similarly, the federal courts have acknowledged that Staff working papers and regulatory guides are "advisory rather than obligatory." *Porter County Chapter of Izaak Walton League of America Inc. v. Atomic Energy Comm'n,* 533 F.2d 1011, 1016 (7th Cir., 1976), *cert. denied*, 429 U.S. 945 (1976)("The working paper, in the words of ASLAB, 'neither represents nor purports to present Atomic Energy Commission policy respecting nuclear power plant sites.' RAI-74-8, 254-255. Similarly, the Regulatory Guide's title page notes that 'Regulatory Guides are not substitutes for regulations, and compliance with them is not required.'"). *See also Comcast Corporation v. F.C.C.*, 526 F.3d 763, 769 (D.C. Cir. 2008)("As we stated in a recent case, '[t]here is no authority for the proposition that a lower component of a government agency may bind the decision making of the highest level") citing *Cmty. Care Foundation v. Thompson*, 318 F.3d 219, 227 (D.C. Cir. 2003); *see also Vernal Enters.*, 355 F.3d at 660; *Jelks v. FCC*, 146 F.3d 878, 881 (D.C. Cir. 1998) (*per curiam*); *Amor Family Broad. Group v. FCC*, 918 F.2d 960, 962 (D.C. Cir. 1991).

This Board reached the same conclusion in ruling on the admissibility of New York State Contention 8 and rejecting the same argument now advanced by Entergy and NRC Staff in reliance on NRC Staff guidance documents and trade association position papers:

> NEI documents, like NEI 95-10, and other regulatory guidance documents, are merely suggestions with no legal authority to supercede the plain language of the regulatory criteria that requires AMR for a structure or component that performs its safety functions without moving parts and without a change in configuration or properties.

ASLB Memorandum and Order (July 31, 2008), at 44-45.

In short, the NEI document, the Grimes memorandum, and the fact that no one has challenged the NRC Staff view that transformers are active components, are, at best, evidence that supports Entergy's position. They are not binding, they are challenged here, and thus they cannot support Entergy's request for summary disposition with regard to New York State Contention 8.

CONCLUSION

For all the reasons stated and in the interest of justice, the State of New York respectfully requests that the Board deny Entergy's motion for summary disposition of Contention 8.

Respectfully submitted
September 23, 2009

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

In re: License Renewal Application Submitted by Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc.	Docket Nos. 50-247-LR and 50-286-LR ASLBP No. 07-858-03-LR-BD01 DPR-26, DPR-64

DECLARATION OF PAUL BLANCH

Paul Blanch, hereby declares under penalty of perjury that the following is true and correct:

1. I have been retained by the New York State Office of the Attorney General to provide expert services in connection with the application by Entergy Nuclear Operations, Inc. and its affiliates (collectively Entergy) for a renewal of the two separate operating licenses for the nuclear power generating facilities located at Indian Point on the east bank of the Hudson River in the Village of Buchanan, Westchester County, New York.

2. I submit this declaration in opposition to Entergy's August 14, 2009 motion for summary disposition that seeks the dismissal of New York State Contention Number 8 concerning transformers.

Experience

3. Beginning in 1964, I served in the U.S. Navy as a nuclear reactor and electric plant operator on *Polaris* class submarines for seven years. These submarines typically were at sea for extended tours of duty. During my Navy service, I and my fellow crew members were in close proximity to the submarines' nuclear reactors that powered the vessels whether they were under the sea or on the surface.

4. As a qualified Electric Plant Operator, I was responsible for the operation of motors, power supplies, inverters, breakers, switchgear, battery chargers, motor and steam-powered electric generators (AC and DC), and transformers.

5. I graduated from the U.S. Navy Electronics Technician School in 1964; the U.S. Navy Nuclear Power School, in 1966; and the U.S. Navy Submarine School, in 1968.

6. As part of my Navy duties, I was certified as an operator/instructor at the Navy prototype reactor (S1C) in Windsor Locks, Connecticut. I instructed Navy officers and enlisted personnel on reactor operations and maintenance including the subjects of electrical theory related to power generation, motors, generators, battery chargers, transformers, transistors, instrumentation and control systems, and magnetic amplifiers.

7. During my Navy service, we employed various test equipment that

included active variable winding ratio transformers commonly referred to as "Variac" transformers.

8. I received an honorable discharge from the Navy in 1971. In 1972, I received a Bachelor of Science in Electrical Engineering from the University of Hartford.

9. I have more than 35 years of engineering, design, operations, maintenance, engineering management, and project coordination experience for the construction and operation of nuclear power plants. This includes positions at Northeast Utilities that involved in the design, construction, operation, and maintenance of Millstone Units 1, 2, and 3 and Connecticut Yankee (Haddam Neck). During this period, I was under the direction of the Electrical Engineering division within Northeast Utilities. I have also been employed by Consolidated Edison and Entergy at Indian Point Unit 2 as an advisor to the Chief Nuclear Officer (CNO) at that facility. I served in a similar position at Maine Yankee reporting to the CNO of Maine Yankee Atomic Power Company.

10. I am a registered professional engineer in the State of California (currently with an inactive status)

11. I have actively participated in industry standards writing activities with the American Nuclear Society (ANS), Instrumentation Society of America (ISA), and the Institute of Electrical and Electronics Engineers, Inc. (IEEE) for use by the nuclear industry.

12. I have been employed as a contractor for the Electric Power Research Institute (EPRI) for the development of computerized monitoring systems for nuclear power plants including monitoring the conditions of active devices including pressure and level monitoring systems.

13. I have been engaged as a contractor to Nuclear Energy Institute (NEI, previously NUMARC) to educate Chief Nuclear Officers on the attributes of a Safety Conscious Work Environment (SCWE).

14. In 1993, I was named "Engineer of the Year" by Westinghouse Electric and Control magazine for my efforts in identifying the subtle failures of active electrical devices such as pressure, level, and flow transmitters and indicators. All of these devices contain active components such as transistors and integrated and digital circuits that require an external energy source. These components, by design, undergo a "change in state" and vary their conductive, resistive, and other properties without moving parts. These devices may also include passive components such as resistors, capacitors, inductors/transformers, and printed circuit boards that do not change state to perform their intended function.

15. I have reviewed the April 30, 2007 License Renewal Application submitted by Entergy to renew the operating licenses for Indian Point Unit 2 and Unit 3. I have also reviewed pertinent sections of the recent August 12, 2009 Safety Evaluation Report prepared by NRC Staff, the August 14, 2009 Motion for Summary Disposition filed by Entergy, and the September 14, 2009 filing by NRC

Staff in support of Entergy's motion. As set out in my November 2007 declaration and as developed in the relevant Contentions contained in the State of New York's Petition to Intervene, it is my opinion that the proposed aging management programs fail to provide reasonable assurance that IP2 and IP3 will operate safely through their proposed license renewal periods.

Transformers

16. A transformer is an electrical device that can convert alternating currents and voltages to different voltages and currents or provide isolation of circuits. Transformers typically contain two insulated wires that are wrapped or coiled around form called a "core" that is frequently made of iron or metal alloys. Transformers contain a primary winding and one or more secondary windings. In its most basic form, a transformer need not even contain a physical core: two coils of wire adjacent to one another can act as a transformer. Two parallel wires or cables may also act as a transformer in that varying current in one wire or conductor may induce voltages and currents in the adjacent wire or conductor.

17. Transformers do not contain any moving parts for their basic functions.[1] During their normal operation, there is no change in the configuration of

[1]While there is a subcategory of transformers that could be viewed as containing active components, those devices are not included within Contention 8. Thus, this description would not apply to "Variac" transformers, which are manually or motor operated variable transformers (manufactured by Staco Energy Products and Variac - Trade Mark of Power Designs, Inc.). Additionally, some transformers may

transformers or their constituent parts, nor are there intended changes in the properties of transformers. Transformers have design properties such as turns ratios, current, voltage, and power. Transformers have the capability to function through a phenomenon known as electromagnetism: when an electrical current input passes through a coil of wire, a magnetic field is generated; in turn, the electrical current is induced from one coil to another through the changing magnetic field. When an electrical current flows into a transformer, that electrical input will create an electromagnetic field within the transformer. Conversely, when there is no current flow into the transformer, there is no magnetic field; the coils and the core do not produce a magnetic field on their own when there is no incoming electrical current. None of these properties and capabilities is designed to change during normal operation of a transformer.

18. The Handbook of Transformer Design & Application states that "Transformers are passive devices for transforming voltage and current." Flanagan, The Handbook of Transformer Design & Application (2nd Edition), page 1.1, McGraw-Hill, 1993, ISBN 0-07-021291-0. Another text book states that a transformer is "a static electrical device, involving no continuously moving parts, used in electrical power systems to transfer power between circuits through use of electromagnetic induction." Harlow, Electric Power Transformer Engineering, page 2-1, CRC Press (2004) ISBN 0-8493-1704-5 (referencing ANSI / IEEE) ; Harlow,

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have cooling systems, but these cooling systems are not necessary for the basic functional capability of the transformer.

Electric Power Transformer Engineering, page 2-1 (2d Edition) CRC Press (2007) ISBN 0-8493-9186-5. The sixth edition of the IEEE Standard Dictionary of Electrical and Electronic Terms includes the following definition of transformer: "A static electrical device consisting of a winding, or two or more coupled windings, with or without a magnetic core, for introducing mutual coupling between electrical circuits." IEEE Standard Dictionary of Electrical and Electronic Terms, IEEE Std 100-1996 (6th Edition), page 1131, ISBN 1-55937-833-6 (1996).

19. Transformers play important roles in the operation of a nuclear power plant. Transformers can come in a variety of sizes. By way of example, some large transformers used at power reactors likely would include Station Auxiliary Transformers, Station Service Transformers, Station Black Out (SBO) transformer, 15 KVA GRD Transformer for the gas turbines, instrumentation transformers, and lighting transformers. Some smaller transformers in use at power reactors would include those used in control circuits. A review of various publicly available electrical one-line diagrams for IP2 and IP3 reflects that there are numerous electrical transformers ranging from 345 KV to 120 volts located throughout the Indian Point facilities that perform a function described in §§ 54.4(a)(1)/(2) and (3). The role of some of the transformers in providing for safety functions is described in Chapter 8 (Electrical Systems) of the UFSAR for each Unit on pp. 1167-68, 1333-43 of the UFSAR for IP3 and on pp. 1039-50 of the UFSAR for IP2. The UFSAR for IP2 includes a one-line diagram for the electrical plan for IP2; that diagram

identifies some of the transformers at IP2 and the central role that they play in the electrical system of the plant. IP2 UFSAR, figure 8.2-1, 8.2-2; Indian Point No.3 Nuclear Power Plant, Electrical Distribution & Transmission System, DWG NO 9321-F-33853, REV 17.

NRC Regulations

20. In preparing this declaration, I reviewed 10 C.F.R. § 54.21. Specifically, § 54.21(a)(1) provides:

> Structures and components subject to an aging management review shall encompass those structures and components—
>
> (i) That perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

(ii) That are not subject to replacement based on a qualified life or specified time period.

10 C.F.R. § 54.21(a)(1)(i), (ii).

21. Based on my review of 10 C.F.R. § 54.21(a)(1), it is my understanding that NRC regulations provide that structures or components without moving parts or without a change in configuration or properties are included within the scope of the rule. The regulation contains a non-exhaustive list of such structures and components. My understanding of the regulation is that those structures and components are to be included in an aging management review. The regulation then also provides another non-exhaustive list of structures and components that are not within the scope of the rule. The NRC has elected to exclude this second category of structures and components from aging management review. 10 C.F.R. § 54.21(a)(1)(i).

22. The text of § 54.21(a)(1)(i) expressly includes the following components as within the first category and therefore within the scope of the regulation: the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets. Because these components are expressly included in the first category, they are subject to aging management review. 10

C.F.R. § 54.21(a)(1)(i).

23. On the other hand, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies are included in the second category and therefore are not subject to aging management review. 10 C.F.R. § 54.21(a)(1)(i).

Comparison of Transformers to Included and Excluded Components

24. In preparing this declaration, I also reviewed the Atomic Safety and Licensing Board's July 31, 2008 decision concerning the admission of various contentions including the admission of New York State Contention No. 8, which concerns transformers. The Board further stated: "In addressing this contention, the Board will require, *inter alia*, representations from the parties to help us determine whether transformers are more similar to the included, or to the excluded, component examples." July 31, 2008 ASLB Memorandum and Order at 45.

25. I have prepared a table that compares the included and excluded structures and components expressly listed in 10 C.F.R. § 54.21(a)(1) to transformers. This table entitled, "Comparison of Various Structures and

Components," accompanies this declaration, and it demonstrates that transformers are similar to the category of structures and components that are expressly listed as included in 10 C.F.R. § 54.21(a)(1) in that transformers, like the included structures and components, contain no moving parts, do not change properties or configuration, and do not undergo any change of state. The table summarizes whether a structure or component contains moving parts, experiences a change in configuration or properties, experiences a change in state, is active or passive, and is specifically listed in § 54.21(a)(1).[2]

26. To be sure, many of these "included" structures and components do change the "properties" of the fluids, voltages, currents, or fuel that travel through or is contained within those structures and components; however, the "properties" of the included structures and components themselves do not change during their intended use. Likewise, a transformer may increase or decrease the voltage of the electrical current that passes through transformer; however, the properties of the transformer itself do not change during its intended use.

27. <u>Electric Cables</u>. Electric cables do not have moving parts. When AC current passes through a cable, a varying magnetic field is generated around the cable. The properties of the currents and voltages in and out of an electric cable

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[2] In my review of 10 C.F.R. § 54.21(a)(1)(i), I observed that the provision does not contain the terms "active," "passive," or a "change in state." I am also aware that the Commissioners have stated "Further the Commission has concluded that 'a change in configuration or properties' should be interpreted to include 'a change in state,' which is a term sometimes found in the literature relating to 'passive.'" 60 Fed. Reg. at 22,477

may change, but the properties of the cable (*e.g.*, resistance, capacitance) are not designed to change. Cables are included as within the scope of §54.21(a)(1).

28. Pipes. The properties of fluids contained within piping may change. These properties of such fluids include pressure, velocity, flow rates, and temperature. The phase of the fluid in a pipe may even change. Yet, a pipe is a component which is included within the scope of § 54.21(a)(1). A pipe's diameter may narrow at a particular location or the pipe may contain a restriction (*e.g.*, "elbow," or "tee") that may change the velocity or pressure of the fluid contained in the pipe; however, the properties of the pipe itself have not changed. Stated differently, the properties of the contents (fluid) may change, but not the conduit (pipe). The pipe itself is not designed to change its own properties.

29. Heat Exchanger. The temperature properties of the fluids contained within a heat exchanger may change, as can a fluid's flow rates. The properties of the fluid in a heat exchanger change in a manner similar to the change in voltage and current that takes place in a transformer. A heat exchanger (another component which is included within the scope of § 54.21(a)(1)) is not designed to change its own properties.

30. Steam Generator. The properties and the state of the fluids in a steam generator may both change. The fluid's temperature may increase and the fluid's state may change from liquid to steam. However, the steam generator itself (another component which is included within the scope of § 54.21(a)(1)) is not

designed to change its own properties during its normal use.

31. Reactor Vessel & Containment. Further, various nuclear processes do occur within the reactor vessel, the containment liner, or the containment, but those components are included in § 54.21(a)(1). Those processes cause some wear on those components, and that wear is the subject of aging management.

32. Turning to transformers, transformers do not have moving parts. The properties of the currents and voltages in and out of a transformer may change, but the properties and configuration of the transformer and its capabilities (ability to transform electricity from one voltage to another) are not designed to change during normal operation. Furthermore, transformers themselves do not experience a "change of state" as that term is commonly used.

Entergy's Argument

33. Dr. Dobbs, in his declaration dated August 12, 2009 presents a position that transformers change "properties" in that:

> *20. The table above (paragraph 19) demonstrates that the voltage and current properties of a transformer change depending on the load condition of the transformer.*

While I agree with the recognition that the "properties" of the current and voltage *inputs* and *outputs* are changed when they pass through a transformer, I disagree with Dr. Dobbs' implication that those are "properties" of the transformer or that the transformer component itself changes. The transformer does not change its configuration or properties during its intended use; the wire coils do not change state, nor does the internal metal core. Input and output voltages are not "properties" of the transformer itself.

34. Dr. Dobbs also contends that a transformer is similar to a transistor in that the properties of the transformer and transistor change with the operation of the device.

35. As noted above, transformers have properties such as turns ratios, resistance, and capacitance and also have the capability to transform electricity from one voltage to another through a magnetic field generated by the input electrical current. None of these properties or capabilities is designed to change during normal operation of a transformer.

36. In contrast, the properties of a transistor itself do change during its normal intended use. Transistors are commonly three wire solid state devices initially made from germanium (Ge) and silicon (Si) semiconductor material. A semiconductor is a material whose resistivity can be changed by applying an electric current to the material; a semiconductor's electrical resistance can vary between that of a conductor (full flow) and that of an insulator (no flow). An external electrical field or voltage changes a semiconductor's resistivity -- which is a property of the component itself. A transistor clearly undergoes a change in its properties and, in some cases, a change in state (from conductor to insulator).

37. This change in resistivity that occurs in the semiconductor can be

thought of as a valve whose position may be changed through an external electric stimulus. A small change in the voltage input to a basic transistor changes the properties (resistance and/or conductance) of the semiconductor. As a result of this applied voltage, the semiconductor changes its properties and may act as an insulator, conductor, or variable resistor controlling relatively large currents. These characteristics are the direct result of a change in properties of the semiconductor. Many transistors such as silicon controlled rectifiers undergo a "change of state" from a conductor to an insulator depending on the applied voltage and the polarity of the applied voltage.

38. A transistor, one of the listed components that are expressly excluded in 10 C.F.R. § 54.21(a)(1)(i), is a device that relies on external power to operate and requires an external source of energy to control its operations.[3] Because of this intended ability to vary its resistivity, it is possible to continuously control the operation of a transistor and its valve-like function by changing its state (its resistivity). Accordingly, a transistor and most other solid state devices are considered active devices whose properties continuously change.

39. Transistors, tubes, magnetic amplifiers, and other active electronic devices have the capability to control and switch large currents and change/amplify

[3] I understand that when the Commissioners modified the license renewal regulations they said "'a change in configuration or properties' should be interpreted to include 'a change in state,' which is a term sometimes found in the literature relating to passive. For example a transistor can 'change its state' and therefore would not be screened in under this description." Final Rule, Nuclear Power Plant License Renewal; Revisions, 60 Fed. Reg. 22,461, 22,477 (May 8, 1995).

the power input. Active devices including transistors and other solid state devices normally require an external source of energy (power supply) to perform its function of power amplification and/or switching. Passive electrical devices, such as resistors, cables, connectors, capacitors, inductors, and transformers are not designed or capable of power amplification, changing conductance, or otherwise changing the output power based upon an external control signal.

40. An analogy may be helpful to understand the active nature of a transistor. One might imagine a simple garden hose that has properties such as internal and external diameters, length, stiffness, and materials of construction. It may also have design capacities such as maximum flow rate and temperature limitations. I would suggest that a hose is a passive device similar to a pipe. When water flows through a hose, the properties of the hose do not change. Increasing or decreasing the flow does not change the properties of the hose. However, if some external force is applied to the hose such as squeezing or crimping the hose with one's hand or foot, the properties of the hose are changed as a result of changing the effective internal diameter of the hose. Turning back to electrical components, a resistor is an electrical component that restricts the flow of electrical current, but it does so at a fixed rate much like a section of hose or pipe. In much the same way that a person might squeeze a hose, the invention of the transistor made it possible for a small voltage from an external source to change the properties of a fixed resistance previously provided by a resistor. Thus, the name "transistor." The

semiconductor in the transistor changes state in much the same way that the diameter of the hose is decreased when someone squeezes the hose. The resistivity properties of a transistor can be changed on an ongoing manner through the application of an external electrical stimulus.

<u>Consequences of Inadequate Management of Transformers</u>

41. As noted in my initial November 2007 declaration and the State of New York's petition, the failure to properly manage aging of Electrical Transformers at Indian Point may compromise:

a. The integrity of the reactor coolant pressure boundary;

b. The capability to shut down the reactor and maintain it in safe shutdown condition; or

c. The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in §§ 50.34(a)(1), 50.67(b)(2), or § 100.11 of this chapter, as applicable. 10 C.F.R. §§ 54.4(a)(1)(2) and (3).

42. The consequence of failures of Electrical Transformers may result in accidents beyond the Design Basis Accidents resulting in exposures to the public exceeding 10 C.F.R. § 100 limits.

43. Failure to properly manage aging of electrical transformers could

result in loss of emergency power to the 480 volt safety equipment and 6.9kV busses including station blackout loads.

44. Recently, there have been a number of transformer failures at power reactors, which although NRC staff believes generally do not involve safety related transformers, provide evidence that since the time of the 1997 Grimes memorandum and 1995 NEI paper, there is a growing realization of the importance of the need for the proper maintenance and aging management of transformers. For example, as discussed in NRC Information Notice 2009-10[4]:

- Indian Point, Unit 3—On April 6, 2007, while operating at 92-percent power, a fault occurred on the No. 31 main transformer resulting in an automatic reactor trip and transformer explosion and fire.
- Limerick Generating Station, Unit 2—On February 1, 2008, a low voltage bushing connection failed on the 2A main transformer resulting in a turbine trip and reactor scram.
- Diablo Canyon, Unit 2—On August 16, 2008, an automatic reactor trip occurred resulting from the failure of the main electrical transformer C phase. Plant operators subsequently declared a Notification of Unusual Event due to an observed fire at the C phase transformer.
- North Anna, Unit 2—On October 29, 2008, while attempting to place the unit on line, the turbine tripped on a generator lockout relay

[4] NRC Information Notice 2009-10, Transformer Failures - Recent Operating Experience, July 7, 2009, ADAMS ML090540218.

actuation. The C main transformer was discovered to be spraying oil.

- Oyster Creek—On November 28, 2008, an electrical fault internal to the M1A main transformer led to an automatic reactor scram due to load reject. That transformer was replaced with the spare, and on February 1, 2009, this replacement transformer failed due to a bushing failure, resulting in a reactor scram, fire, and declaration of a Notification of Unusual Event.

45. In 2003, EPRI published a report that identified a growing problem with failures in large transformers and a wide range of maintenance programs that it recommended be implemented by nuclear utilities to address these problems including the problem of aging degradation of transformers. EPRI Life Cycle Management Planning Sourcebooks, Volume 4, Large Power Transformers, [1007422], March 2003, at 4-1 to 4-6, 4-17 and 6-2 to 6-13

46. In 2006, EPRI published another report that also identified problems with failures in large transformers and a wide range of diagnostic programs that it recommended be implemented by nuclear plant operators to address these problems including the problem of aging degradation of transformers and develop contingency planning to preclude end-of-life failures. EPRI, Large Transformer End-of-Expected-Life Considerations and the Need for Planning [1013566], December 2006

47. In 2006, IEEE published a report listing failure modes of transformers and methods for detecting these failures before they occur. IEEE Guide for the

Evaluation and Reconditioning of Liquid Immersed Power Transformers (IEEE Std C57.140-2006) at 11-15.

48. In 1994, Sandia National Laboratories published a report identifying aging degradation mechanisms for transformers. Sandia, Aging Management Guideline for Commercial Nuclear Power Plants Power and Distribution Transformers, SAND93-7068 · UC-523 Unlimited Release, May 1994, at 4-1 to 4-23.

49. These reports make clear that while some modes of transformer failure can be detected by performance monitoring there are significant transformer failure modes that involve aging degradation of transformer components that do not affect transformer operating performance until the transformer fails and for which aging management programs that go beyond performance monitoring are required.

50. Over time transformers age and can experience failure. For example, over time, the insulation can deteriorate, internal shorts could develop, moisture can collect in the components, or connections can become loose; also, there could be a loss of coolant, an accumulation of oil, dirt, or salt spray, or corrosion.

51. The aging degradation of some constituent parts of transformers is not detected by performance monitoring. Nevertheless, aging management programs could be implemented to address transformer component aging and help to ensure that the transformers will be capable of performing their designated function. Not only should transformers in active operating electrical systems be age managed, but so should transformers that are part of electrical systems that are used less

frequently such as the IP3 transformers for Appendix R (6.9KV/480V), 15 KVA GRD transformers for the gas turbines, Station Service Transformers and transformers for Station Black Out (SBO). Some of these transformers may not normally be energized and/or operating under full load conditions.

52. The 2009 Information Notice, EPRI's 2003 report entitled Large Transformer End-of-Expected-Life Considerations and the Need for Planning [1013566], and IEEE's 2007 report entitled IEEE Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformers[C57.140TM-2006], indicate that current monitoring procedures for detecting the performance of transformers, such as those in use at Indian Point, are not adequate to detect, in advance of failure, all of the aging defects and degradation phenomena in transformers. The declaration of Mr. Rucker makes general reference (at paragraphs 19-21) to monitoring programs that seem to be focused on the performance of the transformers, but not on the condition of the transformer components themselves. Mr. Rucker's declaration contains only generalities about performance monitoring. It also contains many qualifiers that make it difficult to understand the depth or the extent of such monitoring. While it makes reference to "transformers" or "certain" transformers, it does not demonstrate that the licensee will monitor the performance of *all* transformers that would be within the scope of Part 54, nor does it explain how the licensee monitors transformers that may not normally be energized and/or operating under full load conditions.

53. Moreover, simply monitoring the performance of transformers may not ensure that critical transformer components are not degrading to the point of component failure -- now or during the period of license extension. As discussed in the 1994 Sandia Report, the 2003 EPRI report, the 2006 EPRI report, and the 2006 IEEE report, monitoring procedures such as component performance monitoring, personnel training, and quality assurance audits are not adequate. Such monitoring procedures do not provide the level of aging management sufficient to demonstrate that the various transformers will perform their intended functions during the period of extended operation including a potential design basis accident or incident. Additional aging management programs could be implemented to detect aging degradation of transformers and their component parts in advance of failure. *See, e.g.*, EPRI 2003 Report, at 7-2 & sec. 7.1.2. Aging management programs for age related degradation of transformers may include physical inspections, power factor testing, analysis of insulation resistance, oil leakage, gas-in-oil, comparison with original factory test reports, and vibration (humming). By way of example, the 2003 EPRI Report identifies additional testing, surveillance, and inspection techniques that could support a meaningful aging management program. *See, e.g.*, EPRI 2003 Report, at 6-1 to 6-16

54. Attached to this declaration is a true and correct copy of NRC Information Notice 2009-10, Transformer Failures - Recent Operating Experience, July 7, 2009, ADAMS ML090540218 as well as excerpts of: IEEE Standard

Dictionary of Electrical and Electronic Terms, IEEE Std 100-1996 (6th Edition), page 1131, ISBN 1-55937-833-6 (1996); EPRI Life Cycle Management Planning Sourcebooks, Volume 4, Large Power Transformers, [1007422], March 2003; EPRI, Large Transformer End-of-Expected-Life Considerations and the Need for Planning [1013566], December 2006 ; IEEE Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformers [IEEE Std C57.140-2006] 2006; Sandia National Laboratories, Aging Management Guideline for Commercial Nuclear Power Plants Power and Distribution Transformers, SAND93-7068 • UC-523 Unlimited Release, May 1994.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Dated: September 22, 2009
Seattle, Washington

Paul Blanch

Paul Blanch

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IEEE Standard Dictionary of Electrical and Electronic Terms, IEEE Std 100-1996 (6th Edition), page 1131, ISBN 1-55937-833-6 (1996)

UFSAR, Indian Point Unit 2, Chapter 8 (2007)

UFSAR, Indian Point Unit 2, figure 8.2-1, 8.2-2 (electrical drawing)

UFSAR, Indian Point Unit 3, Chapter 8 (2007)

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COMPARISON OF VARIOUS STRUCTURES AND COMPONENTS

Component	Moving Parts	Change In Configuration/ Properties[1]	Change In State[2]	Active or Passive	Included, Excluded In 10 CFR 54.21
Reactor vessel	No	No	No	Passive	Included
Reactor coolant system pressure boundary	No	No	No	Passive	Included
Steam generators	No	No	No	Passive	Included
Pressurizer	No	No	No	Passive	Included
Piping	No	No	No	Passive	Included
Pump Casings	No	No	No	Passive	Included
Valve Bodies	No	No	No	Passive	Included
Core Shroud	No	No	No	Passive	Included
Component Supports	No	No	No	Passive	Included
Pressure Retaining Boundaries	No	No	No	Passive	Included
Heat Exchangers	No	No	No	Passive	Included
Ventilation Ducts	No	No	No	Passive	Included
Containment and Liner	No	No	No	Passive	Included
Penetrations	No	No	No	Passive	Included
Equipment Hatches	No	No	No	Passive	Included
Seismic Structures	No	No	No	Passive	Included
Cable Trays	No	No	No	Passive	Included
Cables and Connectors	No	No	No	Passive	Included
Electrical Cabinets	No	No	No	Passive	Included
Pumps (except casings)	Yes	Yes	Yes	Active	Excluded
Valves (except bodies)	Yes	Yes	Yes	Active	Excluded
Motors	Yes	Yes	Yes	Active	Excluded
Diesel Generators	Yes	Yes	Yes	Active	Excluded
Air Compressors	Yes	Yes	Yes	Active	Excluded
Snubbers	Yes	No	Yes	Active	Excluded
Control Rod Drive	Yes	Yes	Yes	Active	Excluded
Ventilation Dampers	Yes	Yes	Yes	Active	Excluded
Pressure Transmitters[3]	Yes	N.A.	Yes	Active[4]	Excluded
Pressure Indicators	Yes	N.A.	Yes	Active	Excluded
Water Level Indicators	Yes	N.A.	Yes	Active	Excluded
Switchgears	Yes	Yes	Yes	Active	Excluded
Cooling Fans	Yes	Yes	Yes	Active	Excluded
Transistors	No	Yes	Yes	Active	Excluded
Batteries	No	N.A.	Yes	Active	Excluded
Breakers	Yes	Yes	Yes	Active	Excluded
Relays	Yes[5]	Yes	Yes	Active	Excluded
Switches	Yes	Yes	Yes	Active	Excluded
Power Inverters	No	Yes	Yes	Active[6]	Excluded
Circuit Boards	No	Yes	Yes	Active[7]	Excluded
Battery Chargers	No	Yes	Yes	Active[8]	Excluded
Power Supplies	No	No	Yes	Active[9]	Excluded

Table - Comparison of Various Structures and Components

Component	Moving Parts	Change In Configuration/ Properties[1]	Change In State[2]	Active or Passive	Included, Excluded In 10 CFR 54.21
Transformers	No	No	No	Passive	Neither Included nor Excluded
Heaters	No	No	No	Passive	Neither Included nor Excluded
Lamps (incandescent)	No	No	No	Passive	Neither Included nor Excluded
Lamps (LED)	No	Yes	Yes	Active[10]	Neither Included nor Excluded
Lamps (CFL)	No	Yes	Yes	Active[11]	Neither Included nor Excluded
Fuses	No	No	Yes[12]	Active	Neither Included nor Excluded
Resistors Capacitors Inductors	No	No	No	Passive	Neither Included nor Excluded

Endnotes appear on p. T-3

Table Endnotes:

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[1] Change in configuration occurs only with an external energy source applied.

[2] Final Rule, Nuclear Power Plant License Renewal; Revisions, 60 Fed. Reg. 22,461, 22,477 (May 8, 1995): "Further, the Commission has concluded that 'a change in configuration or properties,' should be interpreted to include 'a change in state,' which is a term sometimes found in the literature relating to 'passive.'"

[3] Pressure and level transmitters may or may not contain moving parts. Solid state indicators (LEDs or plasma) contain no moving parts; however, they do contain solid state devices such as transistors.

[4] Most process transmitters and indicators (level, flow, pressure) contain either moving parts or transistors (solid state devices) and are considered "active."

[5] Solid state relays and switches do not contain moving parts; however, they are considered active based upon the Commission's SOC related to transistors.

[6] Power inverters employ solid state and other active devices to convert DC power to AC power. Power output may be controlled by external inputs.

[7] Circuit boards are assumed for the purpose of this discussion to contain active components such as transistors and other solid state devices.

[8] Battery chargers convert AC voltages and currents to DC using solid state active devices such as transistors and rectifiers. Power output may be controlled by external inputs.

[9] Power supplies convert AC voltages and currents to DC regulated voltages using solid state active devices such as transistors and rectifiers.

[10] Light Emitting Diodes (LEDs) change state (conductance) when a voltage is applied. State is determined by the polarity of the applied voltage.

[11] Compact Fluorescent Lights (CFL) lamps contain active devices such as diodes and transistors and may also contain passive devices including transformers.

[12] In order to perform their intended function, fuses undergo a change of state (conductance).

UNITED STATES
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

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In re:

License Renewal Application Submitted by Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc.

Docket Nos. 50-247-LR; 50-286-LR

ASLBP No. 07-858-03-LR-BD01

DPR-26, DPR-64

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SUPPORTING EXHIBITS TO THE DECLARATION OF PAUL BLANCH IN SUPPORT OF THE STATE OF NEW YORK'S RESPONSE TO ENTERGY'S SUMMARY DISPOSITION MOTION AND NRC STAFF'S SUPPORTING ANSWER

Filed on September 23, 2009

List of Supporting Exhibits

1) NRC Information Notice 2009-10, Transformer Failures - Recent Operating Experience (July 7, 2009), ADAMS ML090540218

2) UFSAR, Indian Point Unit 2 (2007), Chapter 8

3) UFSAR, Indian Point Unit 3 (2007), Chapter 8

4) IP2 UFSAR, figure 8.2-1/8.2-2 (electrical drawing)

5) Indian Point No.3 Nuclear Power Plant, Electrical Distribution & Transmission System, DWG NO 9321-F-33853, REV 17 (electrical drawing)

6) EPRI report, Large Transformer End-of-Expected-Life Considerations and the Need for Planning [1013566], March 2006

7) Electrical Power Research Institute, Life Cycle Management Planning Sourcebooks, Volume 4: Large Power Transformers, Final Report, 1007422 (Mar. 2003)

8) IEEE Power Engineering Society, IEEE Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformers (Apr. 27, 2007) (introductory pages and pp. 11-26).

9) Sandia National Laboratories report, Aging Management Guideline for Commercial Nuclear Power Plants Power and Distribution Transformers, SAND93-7068 • UC-523 Unlimited Release, May 1994 (introductory pages and pp. 1-1 through 1-8; 3-44 through 3-70, Chapter 4; and Chapter 5).

10) IEEE STANDARD DICTIONARY OF ELECTRICAL AND ELECTRONIC TERMS, IEEE Std 100-1996 (6th Edition), ISBN 1-55937-833-6 (1996)(p. 1131).

EXHIBIT 1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
OFFICE OF NUCLEAR MATERIAL SAFETY AND SAFEGUARDS
WASHINGTON, DC 20555-0001

July 7, 2009

NRC INFORMATION NOTICE 2009-10: TRANSFORMER FAILURES—RECENT OPERATING EXPERIENCE

ADDRESSEES

All holders of operating licenses for nuclear power reactors under the provisions of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, "Domestic Licensing of Production and Utilization Facilities," except those who have ceased operations and have certified that fuel has been permanently removed from the reactor vessel. All holders of licenses or certificates of fuel cycle facilities. All holders of and applicants for nuclear power plant construction permits under the provisions of 10 CFR Part 50. All holders of licenses or certificates for fuel cycle facilities.

PURPOSE

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to inform addressees of recent operating experience involving failures of large transformers. The NRC expects that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this IN are not NRC requirements; therefore, no specific action or written response is required.

DESCRIPTION OF CIRCUMSTANCES

For several years, available industry operating experience has indicated an increasing trend in transformer failures, and has provided recommendations to reduce the chances of failure. Improved preventive maintenance and monitoring practices have helped to identify some problems before they developed to the point of failure, but the number of large transformers events has not decreased and in fact continues to rise. The following are relatively recent examples involving main power transformers:

- Indian Point, Unit 3—On April 6, 2007, while operating at 92-percent power, a fault occurred on the No. 31 main transformer resulting in an automatic reactor trip and transformer fire. Licensee Event Report (LER) 50-286/2007-002, which can be found on the NRC's public Web site using Agencywide Documents Access and Management System (ADAMS) Accession No. ML071620122, provides additional information.

- River Bend Station—On May 4, 2007, an unplanned manual reactor scram was initiated following the loss of cooling on the No. 2 main transformer (see LER 50-458/2007-002, ADAMS Accession No. ML071840161, for more information).

- Grand Gulf Nuclear Station—On January 12, 2008, a manual reactor scram was initiated following a loss of cooling to the main transformers (see LER 50-416/2008-001, ADAMS Accession No. ML080700702, for more information).

ML090540218

- Limerick Generating Station, Unit 2—On February 1, 2008, a low voltage bushing connection failed on the 2A main transformer resulting in a turbine trip and reactor scram.

- Diablo Canyon, Unit 2—On August 16, 2008, an automatic reactor trip occurred resulting from the failure of the main electrical transformer C phase. Plant operators subsequently declared a Notification of Unusual Event due to an observed fire at the C phase transformer (see LER 50-323/2008-001, ADAMS Accession No. ML082970221, for more information).

- North Anna, Unit 2—On October 29, 2008, while attempting to place the unit on line, the turbine tripped on a generator lockout relay actuation. The C main transformer was discovered to be spraying oil.

- Oyster Creek—On November 28, 2008, an electrical fault internal to the M1A main transformer led to an automatic reactor scram due to load reject. The transformer was replaced with the spare, and on February 1, 2009, this transformer failed due to a bushing failure, resulting in a reactor scram, fire, and declaration of a Notification of Unusual Event (see LER 50-219/2008-001, ADAMS Accession No. ML090260082, and LER 50-219/2009-001, ADAMS Accession No. ML090970735 for more information).

A review of licensees' root cause evaluations for the large transformer failures shows that the events are often the result of ineffective implementation of the transformer maintenance program.

DISCUSSION

The events described above illustrate instances in which the loss or tripping of large transformers resulted in plant transients, reactor trips, unnecessary starting of the emergency diesel generators (EDGs), and declaration of plant events. Transformer failures have resulted in eight declared plant events from January, 2007, to February, 2009, making them the second leading reason for such declarations. While the large transformers discussed in this IN are generally non-safety related, they are within the scope of the Maintenance Rule (Title 10 of the *Code of Federal Regulations,* Section 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants").

A relatively high incidence of transformer failures has occurred in the last few years, the majority of which could have been avoided had the licensee fully evaluated and effectively implemented corrective actions and recommendations identified in industry operating experience. These corrective actions included a more effective maintenance program and a more proactive approach to addressing abnormal indications. In particular, some utilities have installed online automated oil analysis and monitoring system to support decisions regarding preventive and corrective maintenance to improve transformer reliability. The Institute of Electrical and Electronics Engineers (IEEE) provides industry guidance on this matter in Standard C57.140-2006, "IEEE Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformers." However, it should be noted that the NRC has not endorsed this document, and the recommendations it contains do not constitute NRC requirements.

CONTACT

This IN requires no specific action or written response. Please direct any questions about this matter to the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

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NRC generic communications may be found on the NRC public Web site, http://www.nrc.gov. To access this information, select "Electronic Reading Room" and then "Document Collections."

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ADAMS Accession Number: ML090540218 TAC NO. ME0392

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EXHIBIT 2

CHAPTER 8
ELECTRICAL SYSTEMS

8.1 DESIGN BASES

The main generator supplies electrical power at 22-kV through an isolated-phase bus to two half-sized 20.3/345-kV main power transformers. Power required for station auxiliaries during normal operation is split between a 22/6.9-kV unit auxiliary transformer connected to the isolated phase bus and a 138/6.9-kV station auxiliary transformer. This practice provides significant diversity of normal supply power to the redundant safeguards power trains. Following any turbine trip when there are no electrical faults, which require tripping the generator from the network, the generator remains connected to the network for approximately 30 seconds. Upon generator trip, other than a generator over-frequency trip, auxiliaries fed from the unit transformer are "dead-fast" transferred to the station transformer. Provisions for standby (13.8-kV system) and emergency power (diesels) have been included to ensure further the continuity of electrical power for critical loads.

The function of the auxiliary electrical system is to provide reliable power to those auxiliaries required during any normal or emergency mode of plant operation.

Sufficient independence and isolation between the various sources of electrical power is provided in order to guard against concurrent loss of all auxiliary power.

8.1.1 <u>Principal Design Criteria</u>

8.1.1.1 <u>Performance Standards</u>

Criterion: Those systems and components of reactor facilities, which are essential to the prevention or to the mitigation of the consequences of nuclear accidents, which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (GDC 2)

All electrical systems and components vital to plant safety, including the emergency diesel generators, are seismic Class I and are designed so that their integrity is not impaired by the design-basis earthquake, certain wind storms, floods, or disturbances on the external electrical system. Power, control and instrument cabling, motors, and other electrical equipment required for operating the engineered safety features are suitably protected against the effects of a design-basis event or severe external environmental phenomena to ensure a high degree of confidence in their operability in the event that their use is required.

8.1.1.2 Emergency Power

Criterion: An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single component. (GDC 39 and GDC 24)

Emergency power systems are provided with adequate independency, redundancy, capacity, and testability to supply the required engineered safety features and protection systems.

The plant is supplied with emergency power sources as follows:

1. Three independent emergency diesel generators, located in the Diesel Generator Building adjacent to the Primary Auxiliary Building, supply emergency power to the engineered safety features buses in the event of a loss of AC auxiliary power. There are no automatic bus ties associated with these buses. Each diesel generator is started automatically on a safety injection signal or upon the occurrence of an undervoltage condition on any vital 480-V switchgear bus. The system is sufficiently redundant such that any two diesels have adequate capacity to supply the engineered safety features for the design basis accident concurrent with a loss of offsite power. One diesel is adequate to provide power for a safe and orderly plant shutdown in the event of a loss-of-offsite electrical power.

2. Emergency power for vital instrumentation and control and for emergency lighting is supplied from the 125 VDC system via four independent DC channels. The station batteries supply emergency power to the instrumentation and control systems when their associated battery chargers are not available.

8.1.2 1980 Review of 10 CFR 50 Appendix A GDC 17 and GDC 18

Our August 11, 1980 response to the NRC's February 11, 1980 Confirmatory Order included a study of how the plant complied with 10 CFR 50 regulations in effect at that time. The following paragraphs provide a discussion of the extent to which the Indian Point Unit 2 design complies with Criteria 17 and 18 of 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

8.1.2.1 10 CFR 50 Appendix A General Design Criterion 17 - Electric Power Systems

An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

> Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that the core cooling, containment integrity, and other vital safety functions are maintained.
>
> Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

Independent alternate power systems are provided with adequate capacity and testability to supply the required engineered safety features and protection systems.

The plant is supplied with normal, standby, and emergency power sources as follows:

1. The normal source of auxiliary power for 6.9-kV buses 1, 2, 3, and 4 during plant operation is the unit auxiliary transformer, which is connected to the main generator via the iso-phase bus.

2. The normal source of auxiliary power for 6.9-kV buses 5 and 6 and standby power required during plant startup, shutdown, and after reactor trip is the station auxiliary transformer, which is supplied from the Con Edison 138-kV system by either of two separate overhead lines from the Buchanan substation approximately 0.5 mile from the plant. Alternate feeds from the Buchanan 13.8-kV system are also available for immediate manual connection to the auxiliary buses. In addition, three gas turbines with blackstart (no auxiliary power) capability are available. These gas turbines may also be used to "bootstrap" the unit back to power operation following a loss of the Con Edison grid. The capacities of these gas turbine generators require that the station load be reduced to a minimum during startup.

3. Three diesel-generator sets supply emergency power to the engineered safety features buses in the event of a loss of AC auxiliary power. There are no automatic bus ties associated with these buses. The three gas turbines discussed in item 2 may also serve to supply emergency shutdown power.

4. Power for vital instrumentation and controls and for emergency lighting is supplied from the four 125-V DC systems. The station batteries supply emergency power to the instrumentation and control systems when their associated battery chargers are not available.

The emergency diesel-generator sets are located in the Diesel Generator Building adjacent to the Primary Auxiliary Building and supply emergency power to separate 480-V switchgear buses. Each set will be started automatically on a safety injection signal or upon the occurrence of an undervoltage condition on any 480-V switchgear bus. Any two diesels have adequate capacity to supply the required engineered safety features for the design basis accident concurrent with a loss of offsite power. One diesel is adequate to provide power for a safe and orderly plant shutdown in the event of loss-of-offsite electrical power.

All electrical systems and components vital to plant safety, including the emergency diesel generators, are seismic Class I and are designed so that their integrity is not impaired by the design-basis earthquake, certain wind storms, floods, or disturbances on the external electrical system. Power, control and instrument cabling, motors, and other electrical equipment required for operating the engineered safety features are suitably protected against the effects of a design-basis event or severe external environmental phenomena to ensure a high degree of confidence in their operability in the event that their use is required.

The electrical system equipment is arranged so that no single contingency can inactivate enough safeguards equipment to jeopardize plant safety. The 480-V equipment is arranged on four buses (three power trains). Buses 2A and 3A are supplied by the same emergency diesel generator power supply. Buses 5A and 6A are each supplied by one of the remaining two emergency diesel generator power supplies. The 6.9-kV equipment is supplied from six buses.

The plant auxiliary equipment is arranged electrically so that redundant or similar equipment receive power from different sources. The charging pumps are supplied from 480-V buses 3A, 5A, and 6A. The six service water pumps and the five containment fans are similarly supplied from the four 480-V switchgear buses. The two service water pumps, one safety injection pump, and the emergency diesel associated with buses 2A and 3A can be connected to either bus 2A or 3A. Safeguards motor-operated valves are supplied from motor control centers 26A/26AA and 26B/26BB, which are supplied from buses 5A and 6A, respectively.

The 138-kV outside source of power and the 138-kV/6.9-kV station auxiliary transformer are adequate to run all of the plant auxiliary loads.

The bus arrangements specified for operation ensure that power is available to an adequate number of safeguards auxiliaries.

Two diesel generators have enough capacity to start and run a fully loaded set of engineered safeguards equipment. The safeguards equipment with any two of the three power trains can adequately cool the core for any loss-of-coolant incident and maintain the containment pressure within the design value.

The 125-V DC power supplies consist of four separate systems, each having its own battery, battery charger, and power panel. Under normal conditions, each battery charger supplies its DC loads, while maintaining its associated battery at full charge. The battery provides power to the DC loads when the battery charger is not available. DC control power for the 480-V ESF Switchgear and the emergency diesel generators is supplied via automatic transfer switches. Should normal battery voltage fall below a specified level, the associated transfer switch(es) transfer control power from the preferred source to the alternate source. This design eliminates any transfer of load between redundant DC systems 21 and 22, which power the reactor protection and safeguards logics and ensures that adequate DC power is available for starting the emergency diesel generators and for other emergency uses.

The plant turbine generator is the main source of 6.9-kV auxiliary electrical power during "online" plant operation. Power to the auxiliaries is supplied by a 22/6.9-kV two-winding unit auxiliary transformer that is connected to the isophase bus from the generator.

The 6.9-kV system is arranged as six buses. Under normal conditions, two buses (5 and 6) receive power from the 138-kV system via bus main breakers and the 138-6.9-kV station auxiliary transformer. Buses 1, 2, 3, and 4 receive power from the main generator via bus main breakers and the unit auxiliary transformer. Buses 1 and 2 can be tied to bus 5, and buses 3 and 4 can be tied to bus 6 via bus tie breakers when the turbine-generator is shutdown. Buses 2, 3, 5, and 6 each serve one of the four 6900-480-V station service transformers. Normal and offsite power to the 480-V switchgear buses is supplied through these station service transformers.

The 480-V system is arranged as four ESF switchgear buses. Each 480-V switchgear bus supplies several 480-V motor control center buses for power distribution throughout the station. The 480-V switchgear buses are supplied from the 6.9-kV buses as follows: 2A from 2, 3A from 3, 5A from 5, and 6A from 6. Tie breakers are provided between 480-V switchgear buses 2A and 3A, 2A and 5A, and 3A and 6A. These tie breakers are racked out under administrative control when the RCS temperature exceeds 350°F.

The required safeguards equipment circuits are supplied from the 480-V ESF switchgear buses. The normal source of power for buses 5A and 6A is the 138-kV system (via the station auxiliary transformer, 6.9-kV buses 5 and 6, and station service transformers); no transfer is required in the event of a unit trip. Buses 2A and 3A will receive power from the 138-kV system in the event of a unit trip via a "dead fast" transfer of buses 2 and 3 to buses 5 and 6, respectively.

One emergency diesel-generator set supplies emergency power to bus 5A, one to bus 6A, and the third to buses 2A and 3A. Each set will be started automatically on a safety injection signal (see Section 7.2) or upon undervoltage on any 480-V switchgear bus.

Power for the safeguards valve motors is supplied from four motor control centers (26A/26AA and 26B/26BB), which in turn are supplied from the 480-V ESF Switchgear. Motor Control Centers 26A and 26B are provided protection by 480-V circuit breakers. These circuit breakers are on different 480-V switchgear buses, and the bus associated with each circuit breaker has a dedicated emergency diesel generator MCC's 26AA and 26BB are supplied from MCC's 26A and 26B, respectively.

Two independent sources of DC control power are available to the breakers on each 480-V switchgear bus via automatic normal power seeking transfer switches. The preferred and alternate sources of DC control power for the breakers are detailed under Section 8.2.2.3.

Power for instrumentation and control is provided by four 118-V AC Instrument Supply Systems. Each system consists of one inverter, one manual bypass switch, two 118-V AC buses, and associated interconnections. The four inverters are dedicated, one to each system. Each inverter receives power from a different DC Power Panel (DC Power Panel 21 supplies Inverter 21. DC Power Panel 22 supplies Inverter 22, etc.) In the event an inverter, is taken out of service, a backup supply from the 480-V system is available to supply the 118-V AC loads. Failure of a single inverter or its static transfer to switch will not cause the loss of a basic protective system or prevent the actuation of the minimum safeguards devices.

Several sources of offsite power are available to Indian Point Unit 2. These consist of two 138-kV overhead supplies from the Buchanan 138-kV substation, three separate underground feeders from the Buchanan 13.8-kV substation, and three 13.8-kV gas turbines (one of which is located on-site). The 13.8-kV line is rated 19.8 MVA at 13-kV. The 13.8/6.9-kV transformer is rated 20 MVA. The maximum engineered safety feature and safe shutdown loads are 9.2 MVA. No safety or emergency power is required from these sources for the retired Indian Point Unit 1.

The Buchanan 138-kV substation supply to Indian Point Unit 2 has two connections to the Millwood 138-kV substation, a connection to the Peekskill Refuse Burning Generating Station and a connection via auto-transformer to the Buchanan North 345-kV substation. The Indian Point Unit 2 345-kV connection to the system goes to the Buchanan North 345-kV substation, which has connections to Ramapo and Eastview 345-kV substations. System stability studies show that the system is stable for the loss of any generating unit including Indian Point Unit 2.

Each 138-kV overhead tie line can provide offsite power to Indian Point 2 via the station auxiliary transformer. The loss of this transformer would interrupt the 138-kV supply to the station. For this reason, an alternate 13.8/6.9-kV supply is provided.

Additional sources of offsite power from the 13.8-kV distribution system at Buchanan and an independent power supply from the onsite gas turbine (Unit 1) installation are available to 6.9-kV buses 5 and 6 through supply breakers GT-25 and GT-26. The transfer from the normal to the reserve supply (or vice versa) must be accomplished manually.

Three (3) gas turbine generators are directly available to the Indian Point site. One gas turbine generator is more than adequate to provide an additional contingency of backup electrical power for maintaining the plant in a safe shutdown condition.

Gas turbine Unit 1 is located adjacent to the Unit 1 turbine building. The position indication and controls for breakers GT-25 and GT-26 are located on a panel in the Central Control Room.

Gas turbine Units 2 and 3 are located at the Buchanan substation. Either of these gas turbines can supply power to the Unit 2 auxiliary electrical system through the Buchanan 13.8-kV distribution system connections or through the 138-kV tie lines.

Each of these circuits is designed to be available in sufficient time following a loss of all onsite AC power supplies and other offsite electric power circuits, to ensure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. The 138-kV system is designed to be available instantaneously following a loss-of-coolant accident to ensure that core cooling, containment integrity, and other vital safety functions are maintained. This is accomplished by a "dead-fast" transfer scheme that uses stored energy breakers to transfer the auxiliaries on the four 6.9-kV buses supplied by the unit auxiliary transformer to the station auxiliary transformer, which is supplied from the 138-kV system. However, when buses 5 and 6 are supplied from the alternate 13.8-kV supply, the "dead fast" transfer scheme is defeated by manual action to protect the 13.8-kV-6.9-kV transformer.

The diversity and redundancy inherent in the combination of onsite/offsite electrical systems minimize the probability of losing electric power from any of the remaining sources as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of onsite power sources.

The electrical power sources and systems have been evaluated as meeting the requirements of 10 CFR 50.63 (the Station Blackout Rule) (References 3, 4, 5, 6, 7, 8 and 9).

The adequacy of the station electric distribution system voltages was reviewed (as requested by the NRC in Reference 1) for expected normal operating voltage ranges and potential degradations of both the offsite power system and the unit's main electrical generator. The offsite power sources were analyzed under the extremes of load and offsite voltage conditions and credited the automatic load tap changers. To protect safeguards equipment from degraded voltage conditions, which could impair their operation, separate sets of undervoltage relays on each 480-V ESF switchgear bus will alarm to alert the operator that voltage has fallen below approximately 94-percent on any bus and will trip the normal (offsite or main electrical generator) supply breakers to any bus if voltage remains below approximately 88-percent for 180 ± 30 sec. In addition, the 480-V supply breaker to the ESF Switchgear buses will trip upon sustained (10 ± 2 sec) degraded voltage conditions coincident with a safety injection signal. By Reference 2, the NRC concluded that the Indian Point Nuclear Station Unit 2 design is acceptable with respect to the adequacy of station electrical distribution system voltages.

8.1.2.2 <u>10 CFR 50 Appendix A General Design Criterion 18 - Inspection and Testing of Electric Power Systems</u>

Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses, and (2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operation sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

At each refueling interval the 480-V emergency power system is tested to verify that it and vital equipment control systems will respond as designed. The test is initiated by simulating a loss of normal AC station service power.

Testing and surveillance of the station batteries is accomplished as follows:

1. Every month the voltage of each cell, the specific gravity and temperature of a pilot cell in each battery, and each battery voltage are measured and recorded.

2. Every three months each battery is subjected to a 24-hr equalizing charge, and the specific gravity of each cell, the temperature reading of every fifth cell, the height of electrolyte, and the amount of water added are measured and recorded.

3. Each time data are recorded, the new data are compared with the old to detect signs of abuse or deterioration.

4. At each refueling interval, each battery is subjected to a load test and a visual inspection of the plates.

Functional testing is performed in the automatic transfer switches that provide DC control power to the circuit breakers of 480-V Switchgear, Buses 2A, 3A, 5A, and 6A and the emergency diesel-generator control panels. This testing demonstrates that:

(a) Each automatic transfer switch will transfer from its preferred source to its alternate source when the preferred source is unavailable or its voltage falls below a predetermined value,

(b) The preferred and alternate sources of each transfer switch are available to supply DC control power to the breakers and for control of the emergency diesel-generators, and

(c) Each transfer switch will automatically transfer back to its preferred source when the voltage of the preferred source is re-established to an acceptable level.

The safety injection system is tested:

1. To verify that the various valves and pumps associated with the engineered safeguards system will respond and perform their required safety functions.

2. To ensure that each diesel generator will start automatically and assume the required load, within 60 sec after the initial start signal by simulating loss of all normal alternating current station service power supplies and simultaneously simulating a safety injection signal. This test is performed at each refueling interval.

3. To verify that the required bus load shedding takes place.

4. To verify the restoration of particular vital equipment to operation.

Environmental qualification of electrical equipment important to safety is addressed in Section 7.1.

REFERENCES FOR SECTION 8.1

1. Letter from William Gammill, U.S. Nuclear Regulatory Commission, to all Power Reactor Licensees (except Humboldt Bay), Subject: Adequacy of Station Electric Distribution Systems Voltages, dated August 8, 1979.

2. Letter from Steven A. Varga, U.S. Nuclear Regulatory Commission, to John D. O'Toole, Con Edison, Subject: Adequacy of Station Electric Distribution System Voltages, dated October 18, 1982.

3. Letter from Francis J. Williams, U.S. Nuclear Regulatory Commission, to Steven B. Bram, Con Edison, Subject: Supplemental Safety Evaluation of Indian Point Nuclear Generating Unit No. 2, Response to the Station Blackout Rule (TAC No. M68556), dated June 4, 1992.

4. Letter from Con Edison to the Nuclear Regulatory Commission, Subject: Station Blackout Rule, dated April 14,1989.

5. Letter from Con Edison to the Nuclear Regulatory Commission, Subject: Station Blackout Rule, dated March 27,1990.

6. Letter from Con Edison to the Nuclear Regulatory Commission, Subject: Station Blackout Rule, dated October 22, 1993.

7. Letter from Con Edison to the Nuclear Regulatory Commission, Subject: Station Blackout Rule, dated November 30,1993.

8. Letter from Francis J. Williams, U.S. Nuclear Regulatory Commission, to Stephen B. Bram, Con Edison, Subject: Safety Evaluation of the Indian Point Nuclear Generating Unit No.2, Response to the Station Blackout Rule (TAC No. M68556), dated November 21, 1991.

9. Letter from Con Edison to the Nuclear Regulatory Commission, Subject: Station Blackout Rule, dated December 23, 1991.

8.2 ELECTRICAL SYSTEM DESIGN

8.2.1 Network Interconnections

Con Edison's external transmission system provides two basic functions for the nuclear generating station: (1) it provides auxiliary power as required for startup and normal shutdown and (2) it transmits the output power of the station.

Electrical energy generated at 22-kV is raised to 345-kV by the two main transformers. Power is delivered to the system via a 345-kV overhead tie line routed between the main transformers and the 345-kV North Ring Bus at Buchanan Substation. The North Ring Bus is configured with three circuit breakers rated 362-kV, 3000A, 40/63kA. Two of these breakers have synchronizing capability to connect the main generator to the system. The North Ring Bus is also connected to Ramapo and Eastview Substations via overhead transmission circuits and to the Buchanan 138-kV Substation via a 335/138-kV auto-transformer.

The electrical one-line diagram for the Indian Point Station is presented in Plant Drawing 250907 [Formerly UFSAR Figure 8.2-1]. Standby power is supplied to the station from the Buchanan 138-kV Substation, which has two connections to the Millwood 138-kV Substation, one connection to the Peekskill Refuse Burner, and one connection to the Buchanan 345-kV Substation via an auto-transformer. In addition, gas turbine power can be provided to Indian Point Unit 2 from any of the three gas turbines. Several power flow paths exist to connect gas turbine power to the plant, either thru various switching arrangements of 13.8-kV and 6.9-kV underground feeders, or thru combinations of 13.8-kV underground feeders, transformations up through the Buchanan 138-kV, and thru either of the two 138-kV overhead feeders. Maximum flexibility of routing is provided by inter-ties at the Buchanan substation (138-kV and 13.8-kV buses) and at the Indian Point site (138-kV site switchyard and gas turbine substation 6.9-kV bus tie). One of these gas turbine-generators is located at the Indian Point site and two are located at the Buchanan Substation.

A single-line diagram showing the connections of the main generator to the power system grid and standby power source is shown in Plant Drawing 250907 [Formerly UFSAR Figure 8.2-2].

8.2.1.1 Reliability Assurance

Three external sources of standby power are available to Indian Point Unit 2. They are the 138-kV tie from the Buchanan 345-kV substation, the 138-kV Buchanan-Millwood ties, and the gas turbine generators. Loss of any two of these sources will not affect the third. Substantial flexibility and alternate paths exist within each source.

The 138-kV supply from the Buchanan substation with its connections to the Con Edison 345-kV system provides a dependable source of station auxiliary power. Upon loss of 345/138-kV auto-transformer supply at Buchanan, two 138-kV ties are designed to provide additional auxiliary power from the Millwood 138-kV substation. A further guarantee of reliable auxiliary power, independent of transmission system connections, is provided by the three gas turbine generators, one installed at the plant site and two (2) at Buchanan. At least one gas turbine generator (GT-1, GT-2 or GT-3) and associated switchgear and breakers shall be operable at all times. A minimum of 94,870 gallons of fuel for the operable gas turbine shall be available at all times. If these requirements cannot be met, then, within the next seven (7) days, either the inoperable condition shall be corrected or an alternate independent power system shall be established. Additionally, if these requirements cannot be satisfied, the reactor shall be placed in the hot shutdown condition utilizing normal operating procedures. If these requirements cannot be met within an additional 48 hours, the reactor shall be placed in the cold shutdown condition utilizing normal operating procedures. These requirements for the gas turbines ensure that the gas turbines can provide an alternate backup power source in case of loss of onsite emergency power and concurrent loss of offsite power as well as required auxiliary power for alternate safe shutdown systems equipment.

The fuel supply for gas turbines consists of two onsite 30,000-gal fuel oil tanks and a 200,000-gal storage tank located at the Buchanan substation site. A minimum of 94,870 gal of fuel is maintained available and dedicated for the required gas turbine. This minimum fuel inventory ensures that one gas turbine will be capable of supplying the maximum electrical load for the Indian Point Unit 2 alternate safe shutdown power supply system (i.e., 1600kW) for at least 3 days. Commercial oil supplies and trucking facilities exist to ensure deliveries of additional fuel within one day's notice.

In the event of the loss of the Indian Point Unit 2 138-kV supply (the primary preferred offsite supply), the Indian Point Unit 2 13.8/6.9-kV supply is manually connected to 6.9-kV buses 5 and 6. The capacity of this supply is limited and is not capable of supplying full plant load. However, the 13.8-6.9-kV supply is capable of supplying the normal load on buses 5 and 6 and is also capable of supplying all 480-V safeguards and safe shutdown loads. The "dead-fast" transfer of 6.9-kV buses 1, 2, 3, and 4 is prevented by manual action when buses 5 and 6 are supplied from the 13.8/6.9-kV supply.

8.2.2 Station Distribution System

The auxiliary electrical system is designed to provide a simple arrangement of buses requiring a minimum of switching to restore power to a bus in the event that the normal supply is lost.

The basic components of the station electrical system are shown on the electrical one-line diagrams (See Plant Drawings 208377, 231592, 208088, 9321-3004, 249956, 9321-3005, 208507, 249955, 208241, 9321-3006, 248513, 208500, 208502, 208503, 9321-3008, and UFSAR Figure 8.2-4 [Formerly UFSAR Figures 8.2-3, and 8.2-5 through 8.2-16]), which include the main generator, the 345-kV, the 6.9-kV, the 480-V, the 118-V AC instrument, and the 125-V DC systems.

8.2.2.1 Unit Auxiliary, Station Auxiliary, and Station Service Transformers

The plant turbine generator is a main source of 6.9-kV auxiliary electrical power during "online" plant operation. Power to the auxiliaries on 6.9-kV Buses 1 thru 4 is supplied by a 22/6.9-kV two-winding unit auxiliary transformer that is connected to the main generator via the iso-phase bus. Power to the auxiliaries on 6.9-kV buses 5 and 6 during “on line” plant operation is supplied by a 13.8/6.9-kV two-winding station auxiliary transformer connected to an offsite supply. Power to the 480-V buses is supplied from four 6900/480-V, air-insulated, dry-type station service transformers.

These transformers were designed and constructed in accordance with ANSI C57.11, as the applicable standard of record at the time of fabrication. During engineered safeguards loading and operation, these transformers are loaded within their rating. Manufacturer shop tests of the transformers were conducted in accordance with the American Standard Test Code C 57.12.90. This series of tests consisted of the following:

1. Resistance measurements of all windings.
2. Ratio tests.
3. Polarity and phase relation tests.
4. No-load losses.
5. Exciting current.
6. Impedance and load loss.
7. Temperature test.
8. Applied potential tests.
9. Induced potential tests.

The normal source of power to buses 5 and 6 and auxiliary power required during plant startup, shutdown, and after a unit trip is supplied from the 138-kV switchyard. After a unit trip, the auxiliary loads on 6.9-kV Buses 1 through 4 are transferred from the unit auxiliary transformer to the station auxiliary transformer by automatic relay transfer scheme using stored energy breakers. The transfer is monitored by synchrocheck relays (Device 25). The 138-kV system is the normal supply for two of the three power trains of the auxiliary loads associated with plant engineered safeguards.

8.2.2.2 6.9-kV System

The 6.9-kV system is arranged as six buses. During normal plant operation, two buses (5 and 6) receive power from the 138-kV system by bus main breakers and the 138/6.9-kV station auxiliary transformer, while buses 1, 2, 3, and 4 receive power from the main generator by bus main breakers and the unit auxiliary transformer. On a generator trip, other than a generator over-frequency trip, a “dead-fast” transfer scheme ties buses 1 and 2 to bus 5, and bus 3 and 4 to bus 6, by bus tie breakers. In the case of a generator over-frequency trip, the transfer is blocked by an over-frequency transfer interrupt circuit provided for bus protection of out of phase transfer. Plant Drawing 225097 [Formerly UFSAR Figure 7.2-4] is the logic diagram of the transfer scheme. Buses 2, 3, 5, and 6 each serve one 6900/480-V station service transformer.

8.2.2.3 480-Volt System

The 480-V system arranged as ESF Switchgear buses 2A, 3A, 5A, and 6A and numerous motor control center buses. The 480-V switchgear buses are supplied from the 6.9-kV buses as follows: 2A from 2, 3A from 3, 5A from 5, and 6A from 6 (buses 2A and 3A are within the same power train). Tie breakers are provided between 480-V Switchgear buses 2A and 3A, 2A and 5A, and 3A and 6A.

The required safeguards equipment circuits are supplied from the 480-V Switchgear buses. The normal source of power for buses 5A and 6A is the 138-kV system (via the station auxiliary transformer, 6.9-kV buses 5 and 6, and station service transformers); since the normal source of power to these buses is not the main generator, no transfer is required in the event of a unit trip. Buses 2A and 3A are supplied from buses 5 and 6, respectively, via a "dead-fast" transfer of the 6.9-kV buses in the event of a unit trip.

One emergency diesel-generator set provides emergency power to bus 5A, one to 6A, and the other to buses 2A and 3A. Each set will automatically start on a safety injection signal or upon undervoltage on any 480-V switchgear bus.

Power for the safeguards valve motors is supplied from four motor control centers (MCC's 26A, 26AA, 26B, and 26BB). Motor Control Centers 26A and 26B are supplied through separate circuit breakers on different 480-V switchgear buses. Each of these 480-V switchgear buses has a dedicated emergency diesel-generator set. Motor Control Centers 26AA and 26BB are sub fed from MCC's 26A and 26B, respectively.

Loads required for safe shutdown and accident mitigation are supplied from the 480-V switchgear buses and from certain 480-V motor control centers. Other loads are segregated onto other motor control centers. In the event of loss-of-offsite power, loads are stripped from the 480-V buses, the diesel generators are started, and required loads are added in sequence, as described in section 8.2.3.4.

All four 480-V switchgear buses are safety-related and supply power to ESF systems and equipment. Therefore, two independent sources of DC control power are provided for control of 480-V breakers, protective circuits and other devices. This is accomplished by automatic transfer switches located near each switchgear. A transfer from the preferred source to the alternate source occurs when the voltage of the preferred source falls below a predetermined value (100-V DC), provided the voltage of the alternate source is above a predetermined value (112.5-V DC). When the preferred source is restored to 112.5-V DC or higher, the transfer switch will transfer back to the preferred source. With only one source energized, the transfer switch seeks the energized source. Lights indicate the available energized source. Thus, the DC supply for the protection and control of the ESF Switchgear is maintained in the event of a loss of one DC source.

The preferred and alternate sources of DC control power for the breakers are:

Transfer Switch	Associated Bus	Preferred Source	Alternate Source
EDD1	6A	DC PP #24	DC PP #22
EDD2	2A	DC PP #22	DC PP #24
EDD3	3A	DC PP #23	DC PP #21
EDD4	5A	DC PP #21	DC PP #23

8.2.2.4 125-V DC Systems

There are four separate safety-related 125-V DC systems serving the various DC loads throughout the station. Each system consists of one battery, one battery charger, one main power panel and one or more DC distribution panels (sub panels). The systems are similarly arranged, however equipment capacities are not necessarily the same.

Each battery charger is supplied from a different 480-V switchgear bus. Under normal and emergency conditions, the battery charger supplies the DC loads and float charges the battery. The battery provides power to the DC loads under the following conditions:

(a) When the load exceeds the capacity of the battery charger, such as during DC motor starting or simultaneous breaker operation.

(b) When the battery charger is not available, such as a battery charger failure or loss of input voltage.

Bus ties between the main power panels (DC Power Panel 21 and DC Power Panel 22) permit battery and battery charger maintenance.

8.2.2.5 118-V AC Instrument Supply Systems

There are four independent safety-related 118-V AC instrument supply systems serving the various instrumentation and control systems throughout the station. Each system consists of one solid-state inverter with an internal static transfer switch, one manual bypass switch and two 118-V AC instrument buses (See Plant Drawing 250970 [Formerly Figure 8.2-2] for system arrangement and connections to power sources). All four inverters are supplied from different 125-V DC power panels. Each inverter has an alternate input power source (120-V AC nominal), which is used to synchronize the inverter output to the auxiliary electrical system and to provide power to the vital 118-V AC loads in the unlikely event of an inverter failure. The alternate input power source to the inverters is provided by step-down transformers connected to the inverter's static transfer switch. These transformers are supplied from safety-related 480-V MCCs. These feeds are electrically separated from the feeds to the associated battery charger. In the event that an inverter or static transfer switch is out of service, each 118-V AC system has a manual transfer switch mounted in a separate enclosure that can bypass the static transfer switch and provide backup power from the step-down transformers directly to the 118-V AC buses. To ensure that a single failure of an emergency diesel-generator will not result in the unavailibility of more than one 118-V AC system, the normal and backup supplies for three of the instrument buses 21, 22, and 24 are unitized (i.e. fed from the associated emergency diesel-generator). Instrument bus 23 is fed from emergency diesel generators 21 and 22, providing diverse sources to prevent loss of this bus due to loss of a single emergency diesel-generator. Voltage drop calculations demonstrate that equipment supplied from Buses 21 and 21A are operable with the postulated minimum voltage at Inverter 21. This is typical of all instrument buses.

8.2.2.6 Evaluation of Layout and Load Distribution

Electrical distribution system equipment is located to minimize the exposure of vital circuits to physical damage as a result of accidents or natural phenomena. To a certain extent the Diesel-Generator Building is protected from tornados and major tornado generated major missiles because it is situated between large buildings as shown in the site plot plan (Plant Drawing 9321-1002 [Formerly UFSAR Figure 1.2-3]). The diesel-generator installation is considered redundant to other lines of power supply. As described in Section 8.1, there are alternate power supplies. In the case of a tornado, reliance is placed on power supply redundancy and not solely on the diesel installation.

Station Auxiliary, Unit Auxiliary, and the main transformers are located outdoors and are spaced to minimize their exposure to fire, water, and other physical damage.

Surge arresters are installed near the high-voltage terminals of the main and standby transformers to protect the windings from lightning and switching transients, which can cause transformers to fail. All oil-filled transformers are provided with automatic deluge systems to extinguish oil fires quickly and prevent the spread of fire.

The 6.9-kV buses are housed in two metal-clad switchgear units. The enclosures for switchgear 21 and 22 are located at elevation 15 ft in the turbine building. Each breaker is mounted in a separate compartment. Switchgear 21 and 22 have a solid top with cable penetrations and some openings on the side. The cable openings at the top are sealed to minimize bus exposure to fire, water, and other physical damage. An overcurrent condition on any of the 6.9-kV buses actuates the associated bus protection lockout relays, which isolate the bus by tripping and locking out both the normal supply breaker and the 6.9-kV tie breaker for that bus.

The 480-V buses are housed in two metal-enclosed switchgear units located at the 15-ft elevation of the Indian Point Unit 2 control building. The switchgear structure provides protection to minimize exposure from mechanical, fire, and water damage. Buses 5A and 2A are contained in switchgear enclosure 21; Buses 6A and 3A constitute switchgear enclosure 22. The switchgear contains the buses, the bus supply breakers, the tie breakers, the load (feeder) breakers, the station service transformers, and the potential transformers for synchronizing and under-voltage relay protection. The normal 480-V switchgear supply breakers 52/2A, 52/3A, 52/5A, and 52/6A are tripped under the following conditions:

1. Safety injection or unit trip, and loss of voltage (~46-percent) on bus 5A or 6A.
2. Actuation of manual trip pushbuttons on each breaker.
3. Actuation of control switches in the Central Control Room.
4. Actuation of control switches in the Diesel-Generator Building.
5. Individual breaker overcurrent protection.
6. Degraded voltage (~88-percent) for 180 ± 30 seconds on each respective bus.
7. Degraded voltage (~88-percent) coincident with a safety-injection signal for 10 ± 2 seconds.

The "short time" undervoltage relays provide input signals to the sequencing logic and emergency diesel generator start circuitry. Their setpoints (~46-percent) are designed to provide a fast trip response under complete loss-of-power ("dead bus") conditions.

The trip of the normal 480-V supply breakers to the safeguards buses upon sustained under voltage is actuated by two undervoltage relays (set at ~88-percent) on each bus. Two out of two logic will operate an Agastat timing relay (set at 180 ± 30 sec), which in turn trips its respective 480-V supply breaker. This function was added to provide additional protection to the safeguards loads against degraded-voltage conditions. Tripping the 480-V supply breakers to the safeguards buses, upon sustained degraded-voltage conditions coincident with a safety-injection signal for 10 ± 2 sec, protects the motors in addition to providing an alternate power supply to establish a correct voltage.

A separate category alarm and bullet lights in the central control room will alert the operator when any 480-V switchgear bus voltage falls to 94-percent. These may operate during load sequencing operations but they are primarily intended to alert the operator to sustained degraded voltages that result from problems on the offsite power system.

Remote manual and automatic control of the 480-V switchgear breakers and associated relays requires 125-V DC control power. Automatic transfer switches are provided to increase the reliability and availability of DC control power for operation of the 480-V switchgear under normal conditions and during safeguards actuation.

The original plant design provided for transfer between 125-V DC Systems 21 and 22 for each switchgear's DC control power. To improve the reliability of the system and eliminate any potential for transfer-related common-mode failures of DC systems 21 and 22, the transfer schemes were changed to utilize DC systems 23 and 24, which were added after the plant was commissioned. The NRC reviewed this plant change in their safety evaluation report dated 5/2/80, and determined that it met the requirements of Regulatory Guide 1.6 and was therefore acceptable (Reference 1). See Section 8.2.2.3 for the preferred and alternate sources of DC control power for the 480-V switchgear breakers.

Control power for the operation of equipment supplied from each 480-V switchgear bus is arranged to match the preferred and alternate sources of DC control power to the 480-V switchgear breakers. For example, for the equipment supplied from Switchgear Bus 2A, the preferred source of control power is 125-V DC System 22 and the alternate source of control power is 125-V DC System 24.

Four ASCO transfer switches, one per bus, provide DC control power to the 480-V switchgear. Each transfer switch is mounted in a separate enclosure near its respective switchgear breakers.

A similar improved design is provided for the DC control power supplies to the control panels associated with each of the three emergency diesel generators located in the diesel building. DC system 21 is the preferred source and DC System 23 is the alternate source for Diesel-Generator 21; DC System 23 is the preferred source and DC System 22 is the alternate source for Diesel-Generator 22; DC System 24 is the preferred source and DC System 22 is the alternate source for Diesel-Generator 23.

Each 480-V switchgear breaker, with the exception of the Rod Power Supply M-G Set input breakers (52/MG1, 52/MG2) and the reactor trip breakers (52/RTA, 52/RTB, 52/BYA, 52/BYB), is equipped with a Westinghouse "Amptector 1A" solid-state overcurrent trip unit to protect the auxiliary equipment supplied by the breaker (including cables) and the associated switchgear. The settings of the solid-state overcurrent trip unit are based on the supplied load. The solid-state trip unit is provided with an instantaneous and/or short-time setting(s) to protect against fault conditions, and long-time setting to protect against over-load conditions.
Each circuit breaker is tripped on overcurrent conditions (overload or short circuit) by the combined operations of three components:

1. Sensors
2. Amptector solid-state trip unit

3. Actuator

All necessary tripping energy (for a breaker trip on an overcurrent condition only) is derived from the load current flowing through the sensors; no separate power source is required. The tripping characteristics for a specific breaker rating, as established by the sensor rating, are determined by the continuously variable settings of the Amptector static trip unit. This unit supplies a pulse of tripping current (when preselected conditions of current magnitude and duration are exceeded) to the actuator, which produces a mechanical force to trip the breaker.

If an overcurrent condition occurs on one of the 480-V switchgear buses while the bus is supplied from the normal source, lockout relays trip (if required) and prevent the closing of the alternate supply breakers (diesels and bus ties) associated with the bus. These relays must be manually reset after the overcurrent condition is cleared to allow these breakers to close.

The 480-V motor control centers are located in the areas of electrical load concentration. In general, those associated with the turbine generator auxiliary system are located below the turbine generator operating floor level, and those associated with the nuclear steam supply system are located in the primary auxiliary building.

Nonsegregated, metal-enclosed 6.9-kV buses are used for all major bus runs where large blocks of current are carried. The routing of this metal-enclosed bus minimizes its exposure to fire, water, and other physical damage.

The original plant design philosophy maintains all 480VAC breaker controls for engineered safeguards equipment operational following the loss of a 125VDC bus / battery. In the original plant design, two batteries supported three trains of breaker controls by utilizing Battery 21 (Train A), Battery 22 (Train B), and dual inputs from Battery 21 and 22 routed together in a third routing channel to effectively create a Train C. To provide additional capacity, reliability and independence, Indian Point 2 subsequently installed two additional batteries, Battery 23 and Battery 24, which are independent of, and serve as "Swing buses" for the 480VAC breaker and emergency diesel generator controls (Battery 23 with Battery 21 and Battery 24 with Battery 22). This arrangement eliminates any transferring of loads between Batteries 21 and 22.

Train A loads are primarily supported by Diesel Generator 21 and Train B loads are primarily supported by Diesel Generator 23. Selected Train A and Train B loads are supplied from Diesel Generator 22. Train C loads are supported by Diesel Generator 22, with selected Diesel Generator 21 loads. Thus, each load group requires power from a minimum of two diesel generators to fully supply the load group.

The Indian Point Unit 2 cable raceway systems are divided into a maximum of four instrument, four small power & control and three heavy power channels. Where conditions warrant, small power & control and instrumentation cables utilize common raceway to efficiently service localized areas of the plant. For small power and control, a third train is provided.

The application and routing of control, instrumentation, and power cables minimize their exposure to damage from any source. All cables are designed using conservative margins with respect to their current carrying capacities, insulation properties, and mechanical construction. Cable insulation in the reactor building has sheathing selected to minimize the harmful effects of radiation, heat, and humidity. All cables are fire resistant.

The conductors of instrumentation cables are shielded to minimize induced voltages and twisted to minimize magnetic interference. Wire and cables related to engineered safeguards and reactor protection systems are routed and installed to maintain the integrity of their respective redundant channels and to protect them from physical damage.

Cable loading of trays and consequently heat dissipation of cable throughout the plant has been carefully studied and controlled to ensure that there is no overloading. The criteria for electrical loading were developed using IPCEA (now ICEA) Standard P-46-426, manufacturer recommendations, and good engineering practice.

Derating factors for cables in trays without maintained spacing are taken from Table VIII of the IPCEA publication. Derating factors for the maximum ambient temperature existing in any area of the plant are also taken from the IPCEA publication. These factors are applied against ampacities selected from appropriate tables in other portions of the standard.

For physical loading of trays, the following criteria are followed: for 6.9-kV power, one horizontal row of cables is allowed in a tray; for heavy power, two horizontal rows of cables are allowed; for medium power, small power & control or instrumentation, 70-percent of the cross-sectional area of a tray is the maximum fill, with the heavy power cables limited to two horizontal rows. During initial plant construction, a computer program monitored the loading and prevented the routing of anything greater than this amount.

For instrumentation cables, four basic channels are routed through the plant. These channels include cables for systems of 65-V or less. Cables assigned to these four channels are in their respective channels throughout the run.

Certain other cables such as thermocouple cable, public address system cable, and instrument power supplies are run in the four instrument channels.

Control cables are separated into two basic channels with a third channel provided as needed for redundant circuits. These groups of cables are set up for systems more than 65-V and less than 600-V and include multiconductor control cable or other cable as required. Cables assigned to these two channels for separation are in their respective channels and are so designated from the beginning of the cable to the final termination. These cables include:

1. Motor-operated valves - two channels for the redundant valves.
2. Solenoid valves - two channels where required for redundant valves and safeguards. Otherwise not separated.
3. Detector drives - run in any channel as convenient.
4. Motor controls - except safeguards, run in any channel as convenient.
5. Small power cables - run in any channel as convenient.
6. Safeguard control cables - run in two channels as required.
7. Safeguard power cables - separated into sufficient channels to provide minimum functions, e.g., three channels are provided for the containment fan cooler motors.

In response to the NRC's February 11, 1980 Confirmatory Order, Consolidated Edison's August 11, 1980 letter to the NRC identified differences in cable raceway separation between Indian Point Units 2 and 3. Consolidated Edison determined, evaluated, and provided justification for each design difference between Indian Point Units 2 and 3 in submittals to the NRC (References 2, 3) demonstrating that a single failure would not preclude a safety function from being performed. The NRC reviewed these design differences and corresponding justifications and determined the Unit 2 design to be acceptable in their safety evaluation report (Reference 4).

Physical channeling is accomplished by either separate trays or trays with metal dividers and in some cases by separate conduit. The safeguard channeling and control train development, and cable tray separations are shown in Plant Drawings 208376 and 208761 [Formerly UFSAR Figures 8.2-17 and 8.2-18].

In general, redundant circuits are separated horizontally rather than vertically. When physical conditions prevent this, horizontal barriers (i.e., transite or sheet metal barriers) separate heavy power trays from redundant small power & control and instrument trays. To ensure that only fire retardant cables are used throughout the plant, a careful study of cable insulation systems was undertaken early in the design of the plant. Insulation systems that appeared to have superior flame retardant capability were selected and manufacturers were invited to submit cable samples for testing. An extensive flame testing program was conducted including ASTM vertical flame and Con Edison vertical flame and bonfire tests. A report summarizing the testing was prepared by Con Edison. These tests were used as one of the means of qualifying cables, and the specifications were written on the basis of the results.

The following tests were made to determine the flame retardant qualities of the covering and insulations of various types of cables for Indian Point Unit 2:

1. Standard Vertical Flame Test - made in accordance with ASTM-D-470-59T, "Tests for Rubber and Thermoplastic Insulated Wire and Cable."

2. Five-Minute Vertical Flame Test - made with cable held in vertical position and 1750°F flame applied for 5 min.

3. Bonfire Test - consisted of exposing bundles of three or six cables to flame produced by igniting transformer oil in a 12-in. pail for 5 min. The cable bundles were supported horizontally over the center of the pail with the lowest cable 3 in. above the top of the pail. The time required to ignite the cable and the time the cable continued to flame after the fire was extinguished were noted.

On the basis of these tests, cables were selected for the reactor containment vessel penetration. New cables are selected to conform with IEEE 383-1974.

The design and use of fire stops, seals and barriers to meet 10 CFR 50.48 criteria for the prevention of flame propagation where cable and cable trays pass through walls and floors is found in the document under separate cover entitled, "IP2 Fire Hazards Analysis."

In areas where missile protection could not be provided (such as near the reactor coolant system), redundant instrument impulse lines and cables are run by separate routes. These lines are kept as far apart as physically possible or are protected by heavy (0.24 in.) metal plates interposed where inherent missile protection could not be provided by spacing.

In 1989, the NRC approved changes to the design basis with respect to dynamic effects of postulated primary loop ruptures, as discussed in Section 4.1.2.4.

In those areas where the compressed instrument air system is near the essential 480-V switchgear, the following provisions have been incorporated to shield this essential switchgear and cabling from potential missiles or pipe whip:

1. The compressed instrument air lines in the vicinity of the switchgear are supported at the piping bends. This will resist any step loading of PA (which could occur in the event of an instantaneous circumferential rupture) without occurrence of a "plastic hinge." The possibility of pipe whip is eliminated.

2. A guard cover is supplied around the air compressor flywheel. This cover is designed to absorb the translational kinetic energy associated with a compressor flywheel missile.

3. A guard barrier is supplied adjacent to the compression chamber of the air compressor. This barrier is designed to absorb the kinetic energy associated with a compression chamber segment.

These provisions ensure that no missile or whipping pipe originating from postulated failures in the compressed instrument air system will strike the essential switchgear.

8.2.3 Emergency Power

8.2.3.1 Source Descriptions

The three sources of offsite emergency power are: (1) the Con Edison 345-kV system (2) Con Edison's 138-kV system and (3) the licensee's gas turbines. The emergency diesel-generator sets provide three sources of onsite emergency power. Each set is an Alco Model 16-251-E engine coupled to a Westinghouse 900 rpm, 3-phase, 60-cycle, 480-V generator. The units have a capability of 1750 kW (continuous), 2300 kW for 1/2 hour in any 24 hour period, and 2100 kW for 2 hours in any 24 hour period. There is a sequential limitation whereby it is unacceptable to operate EDG's for two hours at 2100 kW followed by operating at 2300 kW for a half hour. Any other combination of the above ratings is acceptable.

Any two units, backups to the normal standby AC power supply, are capable of sequentially starting and supplying the power requirement of at least one complete set of safeguards equipment. The units are installed in a seismic Class I structure located near the Primary Auxiliary Building.

Each emergency diesel is automatically started by two redundant air motors, each unit having a complete 53-ft^3 air storage tank and compressor system powered by a 480-V motor. The piping and the electrical services are arranged so that manual transfer between units is possible. The capability exists to cross-connect a single EDG air compressor to more than one (1) EDG air receiver, via manual air tie valves. However, to ensure that the operability of two (2) of the three (3) EDGs is maintained for minimum safeguards in the event of a single failure, administrative controls are in-place to require an operator to be stationed within the EDG Building, whenever any of the starting air tie valves are opened. Each air receiver has sufficient storage for four normal starts. However, the diesel will consume only enough air for one automatic start during any particular power failure. This is because of the engine control system, which is designed to shut down and lock out any engine that did not start during the initial try. The emergency units are capable of starting and load sequencing within 10 sec after the initial start signal. The units have the capability of being fully loaded within 30 sec after the start of load sequencing.

To ensure rapid start, the units are equipped with water jacket and lube-oil heating. A prelube pump circulates the oil when a unit is not running. The units are located in heated rooms.

Audible and visual alarms are located in the control room and in the diesel generator building. Alarms on the electrical annunciator panels in the control room are:

1. Diesel-generator trouble.
2. Diesel-generator oil storage tank low level.
3. 21 Diesel-Generator Trouble.
4. 22 Diesel-Generator Trouble.
5. 23 Diesel-Generator Trouble
6. Diesel-Generator Service Water Flow Low

The activation of the emergency diesel generator trouble alarm in the control room will be caused by the initiation of any of the following alarms in the diesel generator building:

1. Low oil pressure.
2. Differential fuel strainer, secondary.
3. Overcrank.
4. High differential lube-oil strainer.
5. High water temperature.
6. High differential pressure lube-oil filter.
7. High-high jacket water temperature.
8. Deleted.
9. Overspeed.
10. Overcurrent.
11. Low fuel oil level, day tank.
12. Reverse power.
13. Low start air pressure.
14. Exciter field shutdown.
15. High/Low lube-oil temperature.
16. High differential pressure primary filter.
17. Deleted.

The diesel-generator oil storage tank low level alarm will be energized on a low level in any one of the three fuel-oil storage tanks.

The alarms "21 Diesel-Generator Trouble", "22 Diesel-Generator Trouble", and "23 Diesel-Generator Trouble" located on Panel SG in the Central Control Room will be activated respectively by the following conditions at each EDG local control panel:

1. Loss of DC control power.
2. Engine control switch position (Off or Manual).
3. Breaker control switch position pulled-out [Note - the breaker control switch in the CCR will activate the "Safeguards Equipment Locked Open" alarm (Window 1-8 on Panel SB-1) in the CCR].
4. Engine stop solenoid energized.
5. Day tank level low, primary and backup fuel pump fails to start.
6. For 23 diesel-generator trouble only, loss of voltage on EDG 23 auxiliary load main feed.

There are six electrical contacts, each of which when activated will energize a diesel-generator lockout relay. This lockout relay will, in turn, cause a diesel to shut down if it is operating or will prevent the diesel from responding to an automatic emergency start signal. These contacts are activated by one of the following conditions:

1. Activation of the diesel emergency stop push-button in the diesel-generator building.

2. Activation of the overcurrent relay. A phase-to-phase fault or excessive loads on the diesel generator will operate this relay.

3. Activation of the reverse power relay.

4. Activation of the overcrank relay. If a diesel engine fails to attain speed within 13 sec, this relay will be energized.

5. Activation of the overspeed relay. When the mechanical governor senses 1070 rpm, this relay will be energized.

6. Activation of the low oil pressure relay. This relay is energized by the coincident sensing of lube-oil pressure below 60 psi by two of the three oil pressure switches for each diesel. An oil pressure timer is set to allow 20 sec to pass before tripping the diesel engine lockout relay. This circuit is designed to provide sufficient time for the oil pressure to build up following an engine start.

A safety injection signal will prevent the first three conditions from energizing the diesel engine lockout relay and tripping the diesel generator. Activation of any one of the latter three relays will cause a diesel to stop even when a safety injection signal is present. Shutdown permits corrective action to be taken before the engine is damaged, and the diesel generator can then be returned to normal operation. Once any of these six electrical contacts has been activated causing the diesel engine lockout relay to energize, the lockout relay must be manually reset locally before the diesel can be started.

8.2.3.2 Emergency Fuel Supply

Each of the three emergency diesel generators has its own 175-gal fuel-oil day tank plus an underground bulk storage supply tank and uses diesel oil Specification Number 2. Each day tank is located within the diesel-generator building and supplies its respective engine-mounted fuel-oil pump. The day tank is automatically filled during engine operation from its separate underground storage tank located outside adjacent to the diesel-generator building. Each storage tank has a capacity of 7700 gal and is provided with a motor-driven transfer pump mounted in a manhole opening above oil level. Each pump can be aligned to discharge into the common normal or emergency makeup line to all three diesel-generator fuel-oil day tanks. If a low level is detected in the day tank for diesel generator 21, transfer pump 21 will automatically start to refill the tank to approximately 158 gal. If pump 21 fails to refill the day tank, transfer pump 22 will receive an automatic starting signal as a backup to the primary pump. In a similar manner, transfer pump 22 receives an automatic starting signal on low level in the day tank for diesel 22 and is backed up by transfer pump 23. Transfer pump 23 starts on low level in the day tank for diesel generator 23 and is backed up by transfer pump 21.

Each diesel oil transfer pump stops automatically when 15.5-in. of oil remains in the associated underground tank which equates to a maximum of approximately 7000-gal of available fuel oil per tank. A minimum fuel storage of 19,000 gal (i.e., approximately 6340 gal per tank) is maintained in the three underground storage tanks.

The 19,000 gal of storage ensures that two diesels can operate for at least 73 hours at the maximum load profile permitted by the diesels' ratings. If one of the three storage tanks is not available, there is sufficient fuel oil to run two diesels at the maximum load profile for at least 45 hours.. Similarly, if three diesels are available, there is sufficient fuel oil in the three storage tanks for at least 45 hours of operation at the maximum load profile. These values are based on the use of No. 2 diesel fuel oil at the lowest density of 6.87 lb/gal and engine fuel oil consumption rates based on operating at each load rating. For heavier oil, the time would be increased proportionally to the ratio of 6.87 lb/gal and the actual fuel density. An upper limit of 7.39 lb/gal is common for No. 2 diesel oil.

Additional fuel oil suitable for the diesel engines is stored on the site for gas turbine GT-1 and at Buchanan substation for gas turbines GT-2 and GT-3. A minimum additional storage of 29,000 gal is maintained in the storage tanks dedicated for diesel-generator use. This storage is sufficient for operation of two diesels for at least 111 hours at the maximum load profile permitted by the diesels' ratings. As previously mentioned (Section 8.2.1), commercial oil supplies and trucking facilities exist to ensure deliveries on one day's notice.

The basis for the minimum total required fuel oil quantity of 48,000 gallons is to provide for operation of two diesel generators for 7 days. The specified minimum quantity of fuel oil is based on operation of two diesel generators for 7 days at the maximum load profile permitted by the diesel generator rating. Each diesel is rated for operation for 0.5 hours of operation out of any 24 hours at 2300 kW plus 2.0 hours of operation out of any 24 hours at 2100 kW with the remaining 21.5 hours of operation of any twenty four hours at 1750 kW. Operation of the diesel generators at the maximum load profile ratings bounds the postulated accident load profile. If one EDG storage tank or transfer pump is unavailable, the remaining tanks or pumps with the additional 29,000 gallons of fuel oil can operate two diesels at the maximum load profile permitted by the diesel generator rating for at least 160 hours.

8.2.3.3 Emergency Diesel Generator Separation

The emergency diesel generators are located in a sheet metal, steel-framed building immediately South of the Primary Auxiliary Building. The diesel generators are arranged parallel to each other on 13-ft centers, with approximately 10 ft of clear space between engine components. The engine foundations are surrounded by a 1 foot-high concrete curb containing sufficient volume to hold all the lube-oil or fuel released from a single engine in the event of an inadvertent spill or line break.

Diesel generator separation and fire protection features necessary to meet the criteria of 10 CFR 50.48 are described in the document under separate cover entitled, "IP2 Fire Hazards Analysis." A control panel, which contains relays and metering equipment for all three diesel generators is located on the west end of the building. The panels are compartmentalized with controls for each engine separated from each other. The compartmentalized design minimizes the potential spread of fire to other electrical components. A reinforced-concrete wall separates the diesel generators from the control panel.

Based on the engine manufacturer's case histories of engine failures, missile protection between machines is not considered necessary. Field case histories disclose a complete absence of damage to the engine environs as a result of engine component failure. Engine failures, usually the result of extreme operating conditions, can be classified as follows:

1. Stuck valve.

   A valve sticks open and is struck by the piston. The damaged valve, and possibly part of the piston, enters the exhaust manifold, damages the turbo-charger, and passes harmlessly up the stack. There is no record of a damaged piston generating a missile external to the engine.

2. Piston seizure.

   A piston seizure causes bending and eventual fracture of the connecting rod. All damaged parts remain inside the engine block.

3. Turbo-charger failure.

   A turbo-charger wheel fouls the casing as a result of overspeed or overheat. The robust double-walled casing contains all parts.

4. Engine overspeed.

   The engine's normal operating speed is 900 rpm. Overspeed trips shut off the fuel at each individual fuel injection pump. No cast iron is used in the engine block or base so even if the overspeed trip failed, the engine structure, which is not brittle by nature, would contain any fracture parts. Isolated cases of crank shaft fractures have not resulted in flying missiles.

5. Cylinder head failure.

   Cylinder heads are secured to the block by high-tensile studs. No cap gaskets are used between the head and cylinder liners. This prestressed design, which does not allow slackness to develop, has resulted in an assembly that has not had any incidents of heads flying off, even when failed pistons have pounded the heads. There are also cases on record of improperly timed engines resulting in excessively high firing pressures, over 2000 psi (normal pressure 1600 to 1700 psi), in which the heads have always remained intact.

Operating experience with the Alco engine indicates that internal missiles do not escape from the engine. Alco does not have any evidence of blades coming through the turbo casing. Valves from the engine have broken and been exhausted through the turbo and caused damage to the turbo, but are contained within the casing. There is no evidence of connecting rods escaping from the engine.

To generate any flying parts, the generator would have to be in an overspeed condition beyond what is normally possible with a diesel engine. The construction of the stator windings and stator barrel frame would have to be penetrated by a rotor part in order to escape. The rugged construction of each complements its ability to contain flying objects.

Since the engine has overspeed trips and would not operate much beyond this speed because the valves would hang up, it is concluded that the generator would never reach any critical speeds.

8.2.3.4 Loading Description

Each emergency diesel-generator unit is started on the occurrence of either of the following incidents:

1. Initiation of a safety-injection signal.
2. Undervoltage on any 480-V switchgear bus.

On safety injection or undervoltage on any bus, the engines run at idle and can be connected to deenergized buses by the operator from the control room. Upon blackout (loss of power to bus 5A or 6A) plus unit trip (with no SI), the emergency diesel-generators will be automatically connected to de-energized buses and sequentially loaded, but will continue to idle for live buses.

Upon the activation of a safety injection (SI) signal and blackout (loss of power to bus 5A or 6A) plus unit trip, automatic load sequencing is initiated as follows:

1. All 480-V switchgear feeder breakers, except those supplying motor control centers 26A/26AA, 26B/26BB, 26C, and 211 are tripped on undervoltage and all automatically operated non-safeguard feeder breakers are locked out. (Note – All engineered safeguards motors are supplied from the 480-V system.)

2. The emergency diesel generators are connected to their respective buses. [Note - An alarm (safeguards equipment locked open) will be energized in the Central Control Room if any control switch for the EDG breakers is in the "pull-out" position.]

3. Required engineered safeguards are sequentially started. The list of loads is shown in Table 8.2-2.

4. The operators may energize Motor Control Centers 24A, 27A, and 29A (which feed equipment required for safe shutdown and accident mitigation) and their loads as required.

In an August 11, 1980 response to the NRC's February 11, 1980 Confirmatory Order, Consolidated Edison determined and evaluated the design differences between Indian Point Units 2 and 3 for automatic starting and sequential loading of the emergency diesel generators (EDGs). Whereas the Unit 3 EDGs are automatically connected to supply the 480-V emergency busses on an undervoltage signal, the Unit 2 EDGs will only supply the 480-V emergency busses on a 480-V bus undervoltage signal coincident with a safety injection or a unit trip signal. Each EDG receives automatic starting and sequential loading signals from both control logic Trains. The additional coincidence logic does not preclude manual starting and loading of the EDGs by the operators, and in the absence of a safety injection or unit trip signal, the steam generator water inventory and the steam-driven auxiliary feedwater pump provide sufficient time for such operator action. Consolidated Edison presented each design difference and justification to the NRC (References 2, 3). The NRC reviewed these design differences and corresponding justifications and determined the Unit 2 design to be acceptable in their safety evaluation report (Reference 4).

Load sequencing for the emergency diesel generators during the safety-injection phase of a loss-of-coolant accident is described in References 5 and 6. The logic diagrams for the starting of the emergency diesel-generators and the safeguards sequence are presented in Plant Drawings 225100 and 225101 [Formerly UFSAR Figures 7.2-7 and 7.2-8].

The recirculation phase is initiated manually by control switches on the supervisory panel in the control room as described in Section 6.2.2.1.4.

Loading studies show that the loads on the emergency diesel generators are maintained within their ratings for large loss-of-coolant accidents (as described above), small-break loss-of-coolant accidents, steamline breaks, steam generator tube ruptures, and spurious safety-injection actuations.

Studies have also shown that, in the event of loss of both offsite and gas turbine power, one emergency diesel generator can provide adequate power to bring the plant to cold shutdown.

Tests performed on the emergency power system to verify proper response within the required time limit are detailed in the Technical Specifications. See Section 8.5, Tests and Inspections.

8.2.3.5 Batteries and Battery Chargers

Each of the four battery installations is composed of 58 individual lead-calcium storage cells connected to provide a nominal terminal voltage of 125-V DC. Each battery is fed from a separate charger and each charger is fed from a separate AC power panel. Each battery bus is equipped with a sensitive-type undervoltage relay, which provides alarm/indication of an undervoltage condition. Ground alarms are also provided on each board. Improved status indication of the battery chargers and the direct current system has been provided by segregating the battery charger alarms into four ground alarms and by providing four DC bus trouble alarms, which include an input for low battery terminal voltage. Loads on each battery are shown on Plant Drawings 208501 and 9321-3008 [Formerly UFSAR figures 8.2-15 and 8.2-16]. Loads on the 118-V vital alternating current instrument buses are shown on Plant Drawings 208502 and 208503 [Formerly UFSAR figures 8.2-13 and 8.2-14]. Each battery has been sized to carry its expected shutdown loads for a period of 2 hr following a plant trip and a loss of all AC power. All equipment supplied by the batteries are maintained operable with minimum expected voltages at the battery terminals during the 2 hrs. Each of the four battery chargers has been sized to recharge its own discharged battery within 15 hrs while carrying its normal load.

Seismic design considerations have been adequately included in the design of the battery racks. Stress analyses of these racks assumed worst case conditions of static and dynamic loads in the vertical, horizontal transverse, and horizontal longitudinal direction; stresses were all within allowable values.

8.2.3.6 Reliability Assurance

The electrical system equipment is arranged such that no single accident or incident can inactivate enough safeguards equipment to jeopardize plant safety. The 480-V equipment is arranged on four buses. The 6.9-kV equipment is supplied from six buses.

The plant auxiliary equipment is arranged electrically so that redundant items receive power from different sources. The charging pumps are supplied from 480-V buses 3A, 5A, and 6A. The six service water pumps and the five containment fans are divided among the four 480-V buses. Valves are supplied from motor control centers 26A/26AA and 26B/26BB, which are supplied from buses 5A and 6A, respectively.

The outside source of power is adequate to run all normal operating equipment. The 138/6.9-kV station auxiliary transformer can supply all the auxiliary loads.

The bus arrangements specified for operation ensure that power is available to an adequate number of safeguards auxiliaries.

Two diesel generators have enough capacity to start and run a fully loaded set of engineered safeguards equipment. These safeguards can adequately cool the core for any loss-of-coolant incident and maintain the containment pressure within the design value.

The power supplies to the diesel generators' auxiliary equipment are arranged so that each diesel generator will feed its own auxiliary equipment.

A total loss of DC feed to the switchgear and associated equipment will not cause a loss of offsite power through an inadvertent tripping of the Indian Point Unit 2 light and power supply circuit breakers, because DC is required to trip a breaker. Loss of DC feed to protective relaying will cause an alarm condition rather than initiation of a protective action. If necessary, the light and power circuit breakers in the Buchanan substation may be tripped manually at the breaker mechanisms.

Each independent battery installation is maintained under continuous charge by its associated self-regulating battery charger so that the batteries will always be at full charge in anticipation of a loss-of-ac-power incident. This ensures that adequate DC power will be available for starting and loading the emergency diesel generators and for other emergency uses.

The equipment arrangement in the Indian Point Unit 2 Central Control Room is discussed in Section 7.7.

REFERENCES FOR SECTION 8.2

1. Letter (with attachments) from S. A. Varga, NRC, to W. J. Cahill, Jr., Con Edison, Safety Evaluation Indian Point Unit 2 - Proposed Modification of the 125V DC Battery System, Dated May 2, 1980

2. Letter from William J. Cahill, Consolidated Edison, to Harold R. Denton, NRC, "Confirmatory Order", dated May 9, 1980

3. Letter from John D. O'Toole, Consolidated Edison, to Steven A. Varga, NRC, "Confirmatory Order", dated May 27, 1982

4. Letter from Steven A. Varga, NRC, to John D. O'Toole, Consolidated Edison, "Confirmatory Order", dated December 1, 1982.

5. "Emergency Diesel Generator Loading Study for Indian Point Unit 2," WCAP-12655 (Non-Proprietary Class 3), Rev. June 2002.

6. Letter from Westinghouse to Entergy, IPP-03-187, "EDG Load Study Reconciliation," November 13, 2003.

TABLE 8.2-1
Deleted

TABLE 8.2-2
Diesel Generator Loads

LOAD	D.G. 21 (BUS 5A)	D.G 22 (BUS 2A-3A)	D.G. 23 (BUS 6A)
1. Auxiliary component cooling pumps	1		1
2. Safety injection pumps	1	1	1
3. Residual heat removal pumps		1	1
4. Nuclear service water pumps	1	1	1
5. Containment air recirculation cooling fans	2	2	1
6. Auxiliary feedwater pumps		1	1
7. Spray pumps (if start signal present)	1		1

TABLES 8.2-3 & 8.2-4
Deleted

8.2 FIGURES

Figure No.	Title
Figure 8.2-1	Electrical One-Line Diagram, Replaced with Plant Drawing 250907
Figure 8.2-2	Electrical Power System Diagram, Replaced with Plant Drawing 250907
Figure 8.2-3	Main One-Line Diagram, Replaced with Plant Drawing 208377
Figure 8.2-4	345-KV Installation at Buchanan
Figure 8.2-5	6900-V One-Line Diagram, Replaced with Plant Drawing 231592
Figure 8.2-6	480-V One-Line Diagram, Replaced with Plant Drawing 208088
Figure 8.2-7	Single Line Diagram 480-V Motor Control Centers 21, 22, 23,25, 25A, Replaced with Plant Drawing 9321-3004
Figure 8.2-7a	Single Line Diagram - 480-V Motor Control Centers 24 and 24A, Replaced with Plant Drawing 249956
Figure 8.2-8	Single Line Diagram - 480-V Motor Control Centers 27 and 27A, Replaced with Plant Drawing 9321-3005
Figure 8.2-9	Single Line Diagram - 480-V Motor Control Centers 28 and 210, Replaced with Plant Drawing 208507
Figure 8.2-9a	Single Line Diagram - 480-V Motor Control Centers 29 and 29A, Replaced with Plant Drawing 249955
Figure 8.2-10	Single Line Diagram - 480-V Motor Control Centers 28A and 211, Replaced with Plant Drawing 208241
Figure 8.2-11	Single Line Diagram - 480-V Motor Control Centers 26A and 26B, Replaced with Plant Drawing 9321-3006

Figure 8.2-11a	Single Line Diagram - 480-V Motor Control Center 26C, Replaced with Plant Drawing 248513
Figure 8.2-12	Single Line Diagram - 480-V Motor Control Centers 26AA and 26BB and 120-V AC Panels No. 1 and 2, Replaced with Plant Drawing 208500
Figure 8.2-13	Single Line Diagram - 118-VAC Instrument Buses No. 21 thru 24, Replaced with Plant Drawing 208502
Figure 8.2-14	Single Line Diagram - 118-VAC Instrument Buses No. 21A thru 24A, Replaced with Plant Drawing 208503
Figure 8.2-15	Single Line Diagram - DC System Distribution Panels No. 21, 21A, 21B, 22, and 22A, Replaced with Plant Drawing 208501
Figure 8.2-16	Single Line Diagram - DC System Power Panels No. 21 thru 24, Replaced with Plant Drawing 9321-3008
Figure 8.2-17	Single Line Diagram of Unit Safeguard Channeling and Control Train Development, Replaced with Plant Drawing 208376
Figure 8.2-18	Cable Tray Separations, Functions, and Routing, Replaced with Plant Drawing 208761

8.3 ALTERNATE SHUTDOWN SYSTEM

The Indian Point Unit 2 alternate safe shutdown system provides the necessary functions to maintain the plant in a safe shutdown condition following a fire that damages the capability to power and control essential equipment from normal and emergency Indian Point Unit 2 sources.

In the unlikely event of a major fire or other external event affecting redundant cabling or equipment in certain areas, electrical power could be disrupted to safe shutdown components and systems. However, following the unlikely loss of normal and preferred alternate power, additional independent and separate power supplies from the Indian Point Unit 1 440-V switchgear are provided for a number of safe shutdown components. A detailed description of the alternate safe shutdown system including its functions, components, and operation is provided in the document under separate cover entitled, "IP2 10 CFR 50, Appendix R Safe-Shutdown Separation Analysis."

8.3 FIGURES

Figure No.	Title
Figure 8.3-1	Deleted

8.4 MINIMUM OPERATING CONDITIONS

The electrical system is designed such that no single contingency can inactivate enough safeguards equipment to jeopardize plant safety. The minimum operating conditions define those conditions of electrical power availability necessary (1) to provide for safe reactor operation and (2) to provide for the continuing availability of engineered safety features. The facility Technical Specifications, Section 3.8, include minimum operating conditions covering the following plant conditions:

1. Minimum electrical conditions for reactor criticality.
2. Minimum electrical conditions during power operation.

8.5 TESTS AND INSPECTIONS

Emergency Diesel generators are tested in accordance with technical specification requirements. The tests specified are designed to demonstrate that the emergency diesel generators will provide power for the operation of equipment. They also ensure that the emergency generator system controls and the control systems for safeguards equipment will function automatically in the event of a loss of all normal 480-V AC station service power.

The testing frequency specified is often enough to identify and correct deficiencies in systems under test before they can result in a system failure. The fuel supply and starting circuits and controls are continuously monitored and any faults are alarm indicated. An abnormal condition in these systems would be signaled without having to place the emergency diesel generators on test.

The Emergency Diesel Generators will be inspected in accordance with a licensee controlled maintenance program. The maintenance program will require inspection in accordance with the manufacturer's recommendation for this class of standby service. Changes to the maintenance program will be controlled under 10 CFR 50.59.

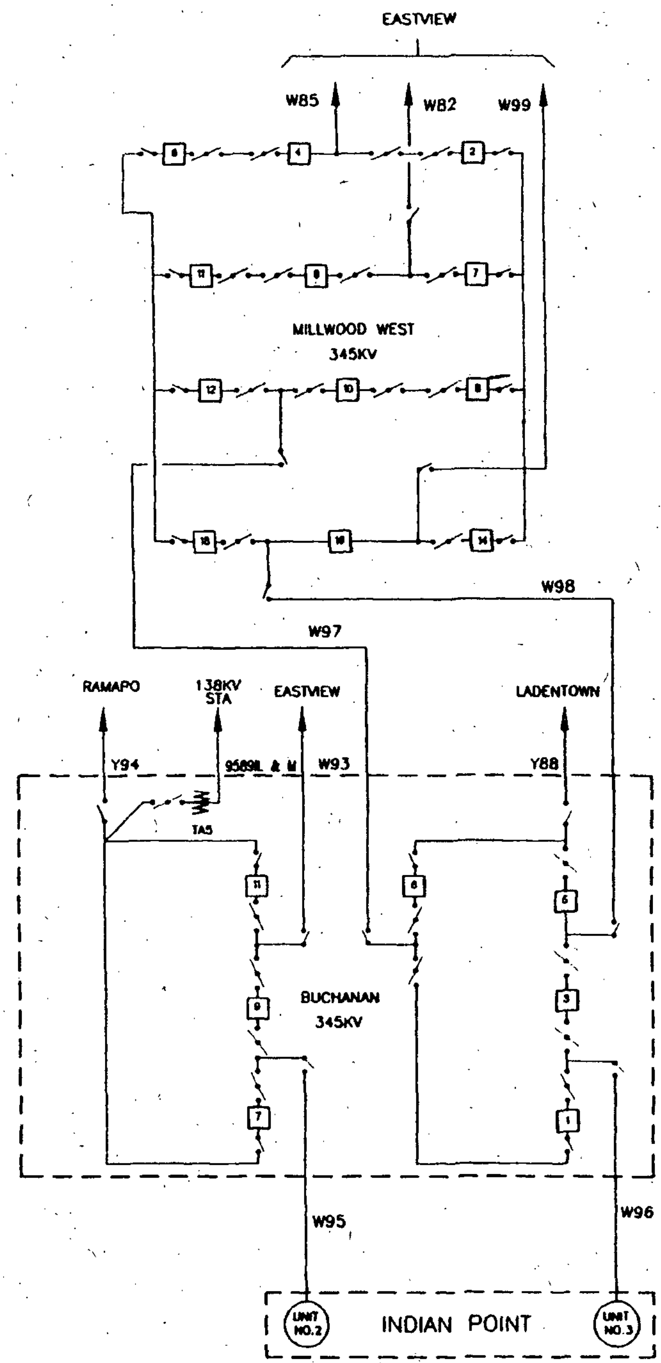
Station batteries will deteriorate with time, but precipitous failure is extremely unlikely. The surveillance specified is that which has been demonstrated over the years to provide an indication of a cell becoming unserviceable long before it fails. The periodic equalizing charge will ensure that the ampere-hour capability of the batteries is maintained.

The 'refueling interval' load test for each battery, together with the visual inspection of the plates, will assure the continued integrity of the batteries. The batteries are of the type that can be visually inspected, and this method of assuring the continued integrity of the battery is proven standard power plant practice.

At monthly intervals, at least one gas turbine shall be started and synchronized to the power distribution system for a minimum of thirty (30) minutes with a minimum electric output of 2000kW. At weekly intervals, the minimum gas turbine fuel volume 94,870 gallons shall be verified to be available and shall be documented in the plant log. These tests and surveillances are designed to assure that at least one gas turbine will be available to provide power for operation of equipment, if required. Since the Indian Point 2 alternate safe-shutdown power supply system demands a maximum electrical load of approximately 1600 kW, the required minimum test load will demonstrate adequate capability.

In addition, the required minimum gas turbine fuel oil storage volume of 94,870 gallons will conservatively assure at least three (3) days of operation of a gas turbine generator.

The specified test frequencies for the gas turbine generator(s) and associated fuel supply will be adequate to identify and correct any mechanical or electrical deficiency before it can result in a component malfunction or failure.

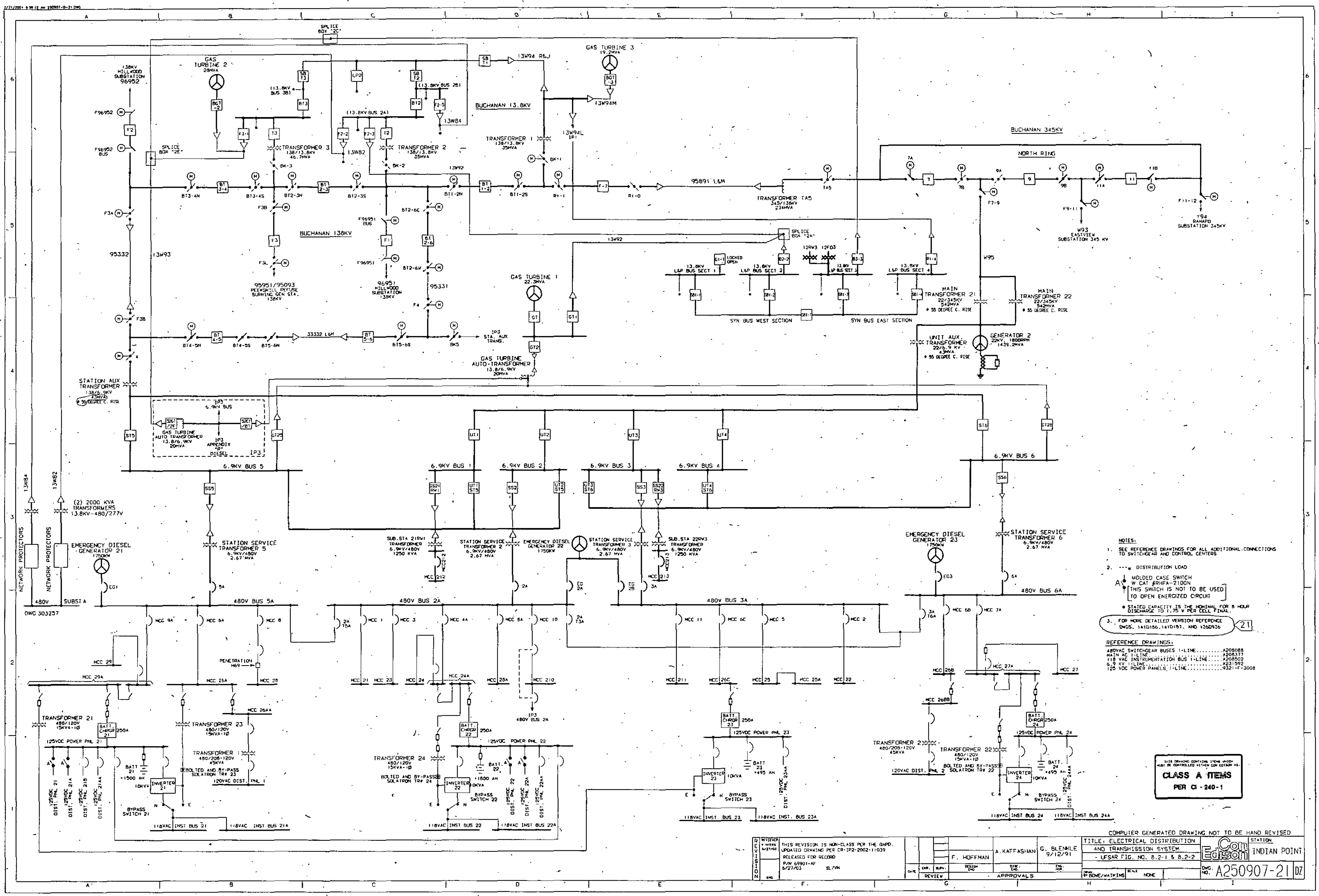


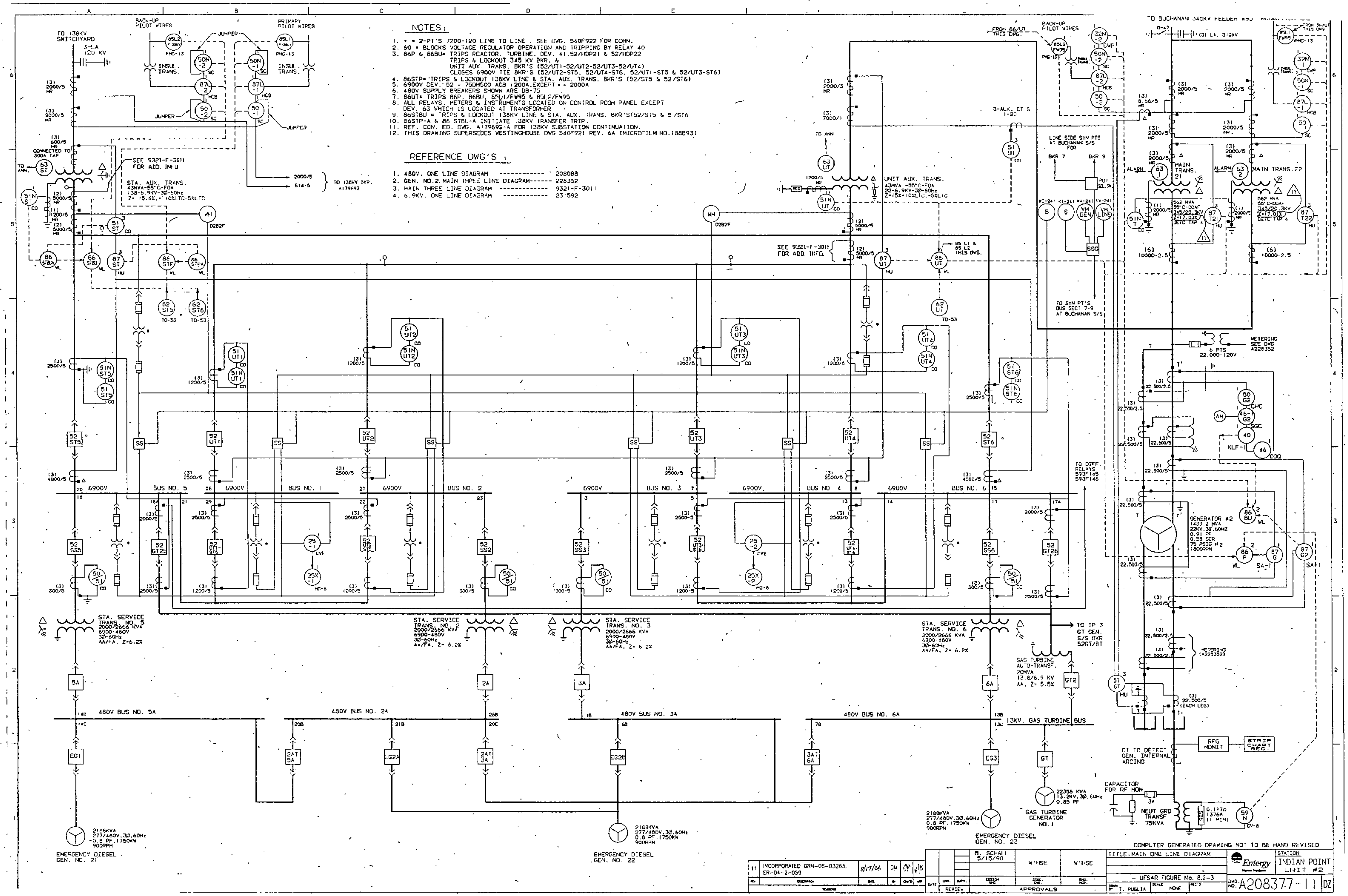
INDIAN POINT UNIT No. 2

UFSAR FIGURE 8.2-4

345KV INSTALLATION
AT BUCHANAN

MIC. No. 1999MC3885 | REV. No. 17A


BUCHANAN 13.8KV
BUCHANAN 138KV
BUCHANAN 345KV
NORTH RING
GAS TURBINE 1 22.3MVA
GAS TURBINE 2 28MVA
GAS TURBINE 3 19.2MVA
TRANSFORMER 1 138/13.8KV 35MVA
TRANSFORMER 2 138/13.8KV 35MVA
TRANSFORMER 3 138/13.8KV 46.7MVA
TRANSFORMER TA5 345/138KV 234MVA
95891 L&M
W93 EASTVIEW SUBSTATION 345 KV
Y94 RAMAPO SUBSTATION 345KV
138KV HILLWOOD SUBSTATION 96952
95951/95093 PEEKSKILL REFUSE BURNING GEN STA. 138KV
96951 HILLWOOD SUBSTATION 138KV
33332 L&M
MAIN TRANSFORMER 21 22/345KV 542MVA
MAIN TRANSFORMER 22 22/345KV 542MVA
GENERATOR 2 22KV, 1800RPM 1439.2MVA
UNIT AUX. TRANSFORMER 22/6.9 KV 43MVA
SYN BUS WEST SECTION
SYN BUS EAST SECTION
GAS TURBINE AUTO-TRANSFORMER 13.8/6.9KV 20MVA
STATION AUX TRANSFORMER 138/6.9KV 43MVA
6.9KV BUS 5
6.9KV BUS 1
6.9KV BUS 2
6.9KV BUS 3
6.9KV BUS 4
6.9KV BUS 6
(2) 2000 KVA TRANSFORMERS 13.8KV-480/277V
NETWORK PROTECTORS
EMERGENCY DIESEL GENERATOR 21 1750KW
EMERGENCY DIESEL GENERATOR 22 1750KW
EMERGENCY DIESEL GENERATOR 23 1750KW
STATION SERVICE TRANSFORMER 5 6.9KV/480V 2.67 MVA
STATION SERVICE TRANSFORMER 2 6.9KV/480V 2.67 MVA
STATION SERVICE TRANSFORMER 3 6.9KV/480V 2.67 MVA
STATION SERVICE TRANSFORMER 6 6.9KV/480V 2.67 MVA
480V BUS 5A
480V BUS 2A
480V BUS 3A
480V BUS 6A
DWG 303257
125VDC POWER PNL 21
125VDC POWER PNL 22
125VDC POWER PNL 23
125VDC POWER PNL 24
118VAC INST BUS 21
118VAC INST BUS 21A
118VAC INST BUS 22
118VAC INST BUS 22A
118VAC INST. BUS 23
118VAC INST. BUS 23A
118VAC INST BUS 24
118VAC INST BUS 24A
NOTES:
1. SEE REFERENCE DRAWINGS FOR ALL ADDITIONAL CONNECTIONS TO SWITCHGEAR AND CONTROL CENTERS
2. DISTRIBUTION LOAD
MOLDED CASE SWITCH W CAT #RHFA-2100N THIS SWITCH IS NOT TO BE USED TO OPEN ENERGIZED CIRCUIT
* STATED CAPACITY IS THE NOMINAL FOR 8 HOUR DISCHARGE TO 1.75 V PER CELL FINAL.
3. FOR MORE DETAILED VERSION REFERENCE DWGS. 141D186, 141D187, AND 136D936
REFERENCE DRAWINGS:
480VAC SWITCHGEAR BUSES 1-LINE A208088
MAIN AC 1-LINE A208377
118 VAC INSTRUMENTATION BUS 1-LINE A208502
6.9 KV 1-LINE A231592
125 VDC POWER PANELS 1-LINE 9321-F-3008
CLASS A ITEMS PER CI - 240 - 1
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
THIS REVISION IS NON-CLASS PER THE QAPD. UPDATED DRAWING PER CR-IP2-2002-11039
RELEASED FOR RECORD
F. HOFFMAN
A. KAFFASHAN
G. BLENKLE 9/12/91
APPROVALS
TITLE: ELECTRICAL DISTRIBUTION AND TRANSMISSION SYSTEM - UFSAR FIG. NO. 8.2-1 & 8.2-2
Con Edison
STATION INDIAN POINT
DWG. NO. A250907-21



NOTES:

1. • = 2-PT'S 7200-120 LINE TO LINE . SEE DWG. 540F922 FOR CONN.
2. 60 • BLOCKS VOLTAGE REGULATOR OPERATION AND TRIPPING BY RELAY 40
3. 86P & 86BU= TRIPS REACTOR, TURBINE, DEV. 41,52/HDP21 & 52/HDP22
   TRIPS & LOCKOUT 345 KV BKR. &
   UNIT AUX. TRANS. BKR'S (52/UT1-52/UT2-52/UT3-52/UT4)
   CLOSES 6900V TIE BKR'S (52/UT2-ST5, 52/UT4-ST6, 52/UT1-ST5 & 52/UT3-ST6)
4. 86STP= TRIPS & LOCKOUT 138KV LINE & STA. AUX. TRANS. BKR'S (52/ST5 & 52/ST6)
5. 6900V DEV. 52 = 75DH500 ACB 1200A,EXCEPT ∘ = 2000A
6. 480V SUPPLY BREAKERS SHOWN ARE DB-75
7. 86UT= TRIPS 86P, 86BU, 85L1/FW95 & 85L2/FW95
8. ALL RELAYS, METERS & INSTRUMENTS LOCATED ON CONTROL ROOM PANEL EXCEPT DEV. 63 WHICH IS LOCATED AT TRANSFORMER
9. 86STBU = TRIPS & LOCKOUT 138KV LINE & STA. AUX. TRANS. BKR'S(52/ST5 & 5 /ST6
10. 86STP-A & 86 STBU-A INITIATE 138KV TRANSFER TRIP.
11. REF. CON. ED. DWG. A179692-A FOR 138KV SUBSTATION CONTINUATION.
12. THIS DRAWING SUPERSEDES WESTINGHOUSE DWG 540F921 REV. 6A (MICROFILM NO.188893)

REFERENCE DWG'S :

1. 480V. ONE LINE DIAGRAM ------------ 208088
2. GEN. NO.2 MAIN THREE LINE DIAGRAM------ 228352
3. MAIN THREE LINE DIAGRAM ------------ 9321-F-3011
4. 6.9KV. ONE LINE DIAGRAM ------------ 231592

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REV	DESCRIPTION	DATE	BY	CHK'D	APP
11	INCORPORATED DRN-06-03263, ER-04-2-059	8/17/06	DM		

REVIEW: B. SCHALL 5/15/90 — APPROVALS: W'HSE, W'HSE

TITLE: MAIN ONE LINE DIAGRAM

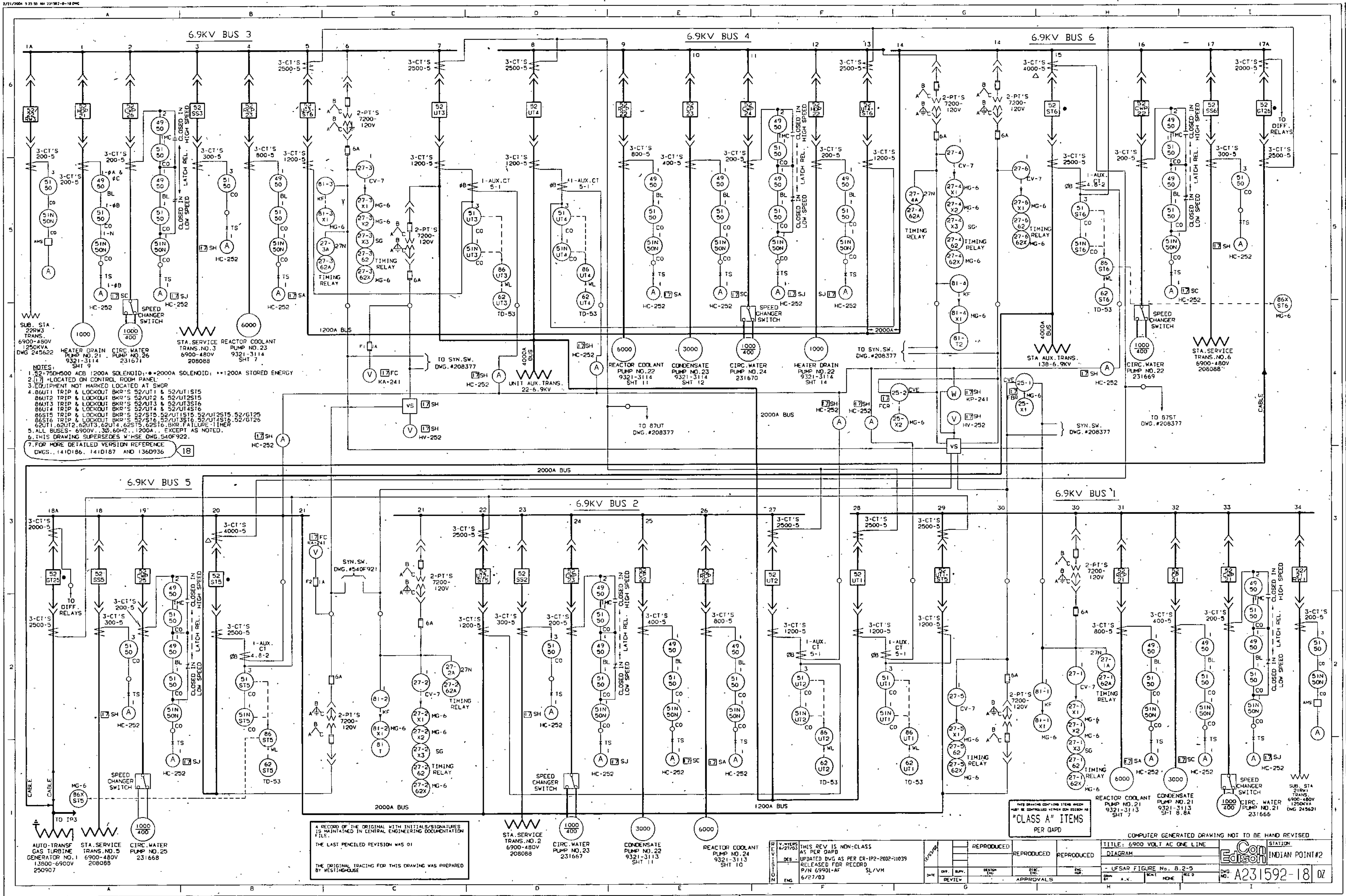
– UFSAR FIGURE No. 8.2-3

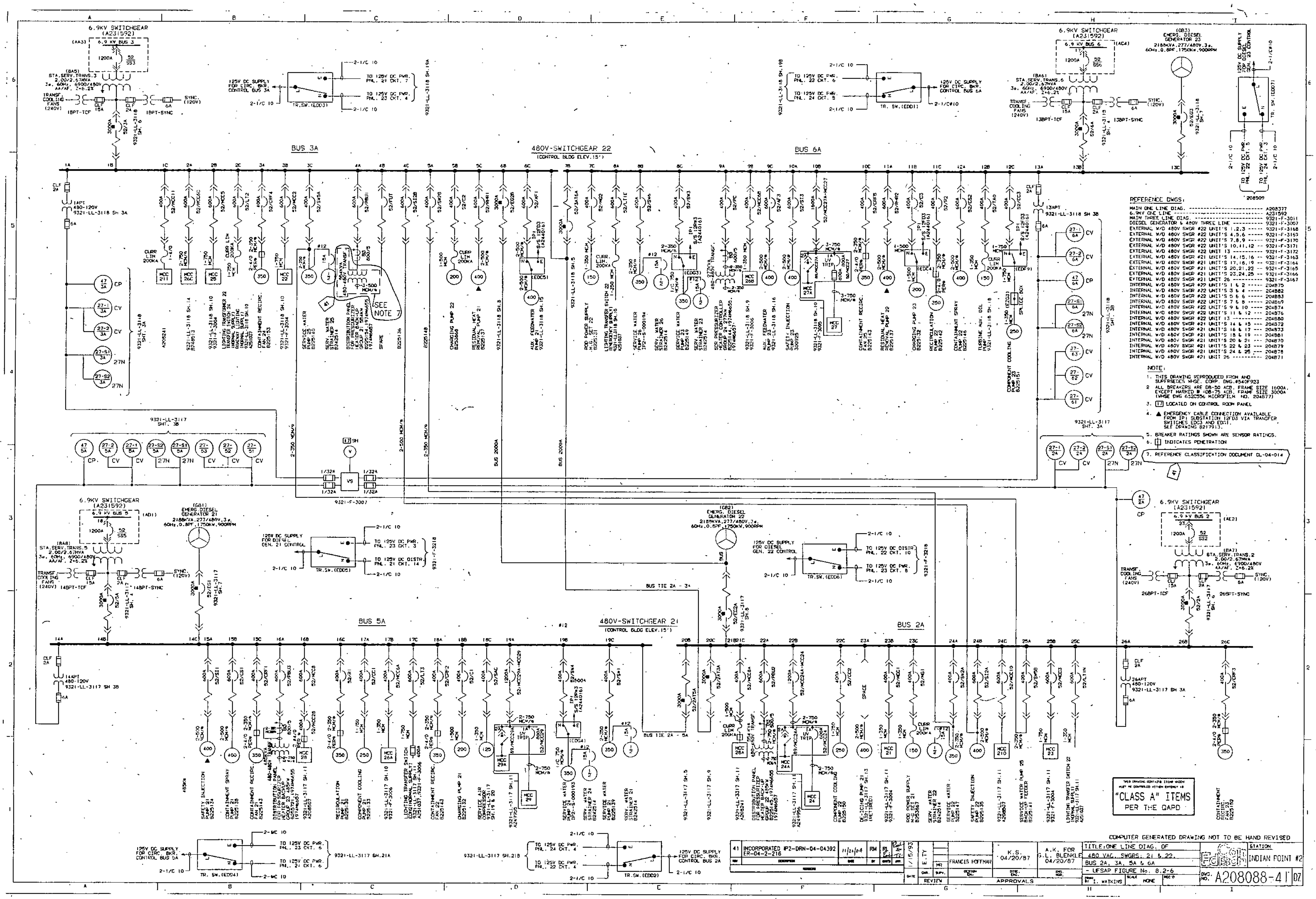
DRAWN BY T. PUGLIA — SCALE NONE

Entergy

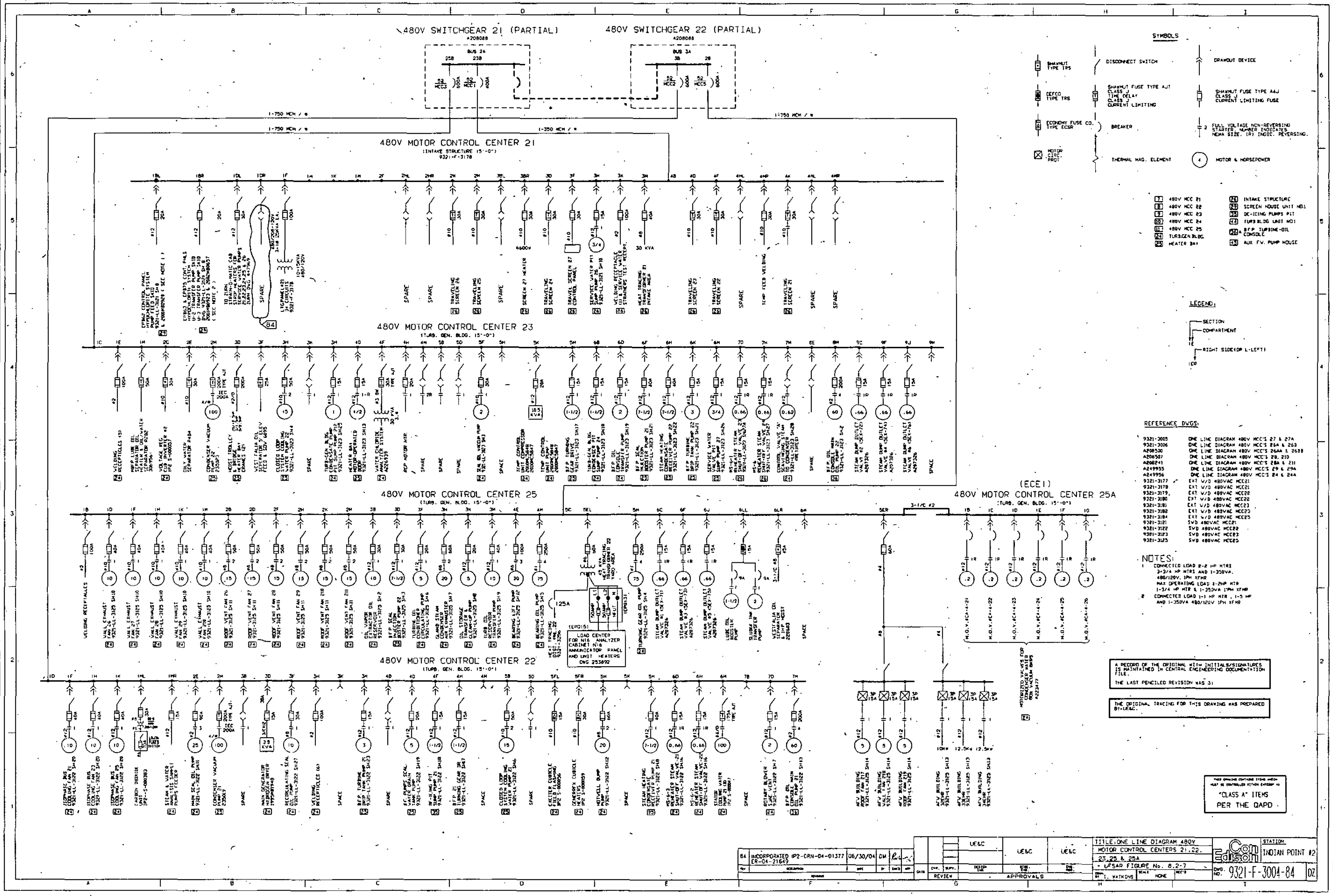
STATION: INDIAN POINT UNIT #2

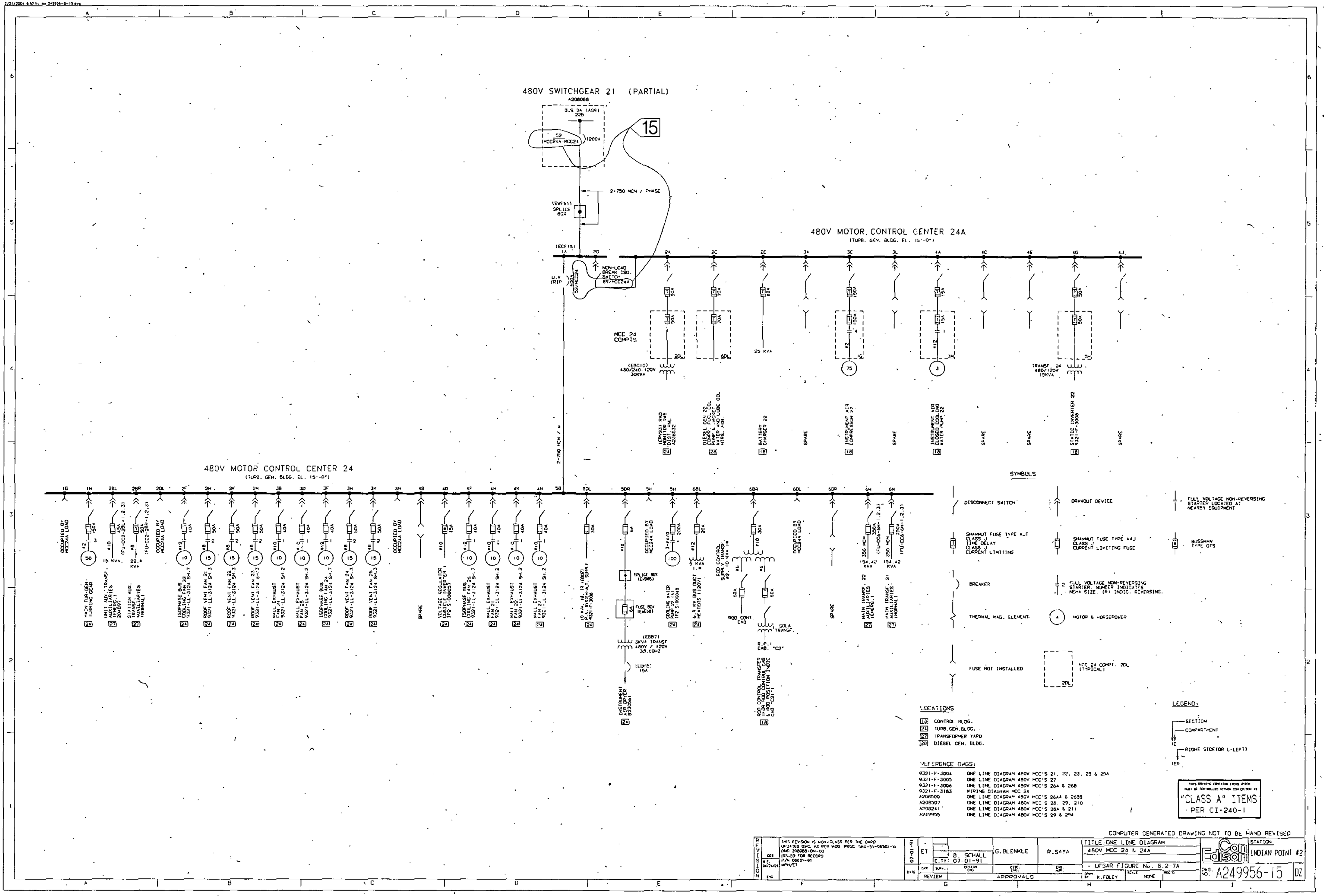
DWG. NO. A208377-11 DZ


6.9KV BUS 3
6.9KV BUS 4
6.9KV BUS 6
6.9KV BUS 5
6.9KV BUS 2
6.9KV BUS 1
SUB. STA 22RW3 TRANS. 6900-480V 1250KVA DWG 245622
HEATER DRAIN PUMP NO.21 9321-3114 SHT 9
CIRC.WATER PUMP NO.26 231671
STA.SERVICE TRANS.NO.3 6900-480V 208088
REACTOR COOLANT PUMP NO.23 9321-3114 SHT 7
UNIT AUX.TRANS. 22-6.9KV
REACTOR COOLANT PUMP NO.22 9321-3114 SHT 11
CONDENSATE PUMP NO.23 9321-3114 SHT 12
CIRC.WATER PUMP NO.24 231670
HEATER DRAIN PUMP NO.22 9321-3114 SHT 14
STA AUX.TRANS. 138-6.9KV
CIRC.WATER PUMP NO.22 231669
STA.SERVICE TRANS.NO.6 6900-480V 208088
AUTO-TRANSF GAS TURBINE GENERATOR NO.1 13800-6900V 250907
STA.SERVICE TRANS.NO.5 6900-480V 208088
CIRC.WATER PUMP NO.25 231668
STA.SERVICE TRANS.NO.2 6900-480V 208088
CIRC.WATER PUMP NO.23 231667
CONDENSATE PUMP NO.22 9321-3113 SHT 11
REACTOR COOLANT PUMP NO.24 9321-3113 SHT 10
REACTOR COOLANT PUMP NO.21 9321-3113 SHT 7
CONDENSATE PUMP NO.21 9321-3113 SHT 8.8A
CIRC. WATER PUMP NO.21 231666
SUB. STA 21RW1 TRANS. 6900-480V 1250KVA DWG 245621
NOTES:
1.52=75DH500 ACB 1200A SOLENOID; ●=2000A SOLENOID: **1200A STORED ENERGY
2.17 =LOCATED ON CONTROL ROOM PANEL
3.EQUIPMENT NOT MARKED LOCATED AT SWGR
4.86UT1 TRIP & LOCKOUT BKR'S 52/UT1 & 52/UT1ST5
86UT2 TRIP & LOCKOUT BKR'S 52/UT2 & 52/UT2ST5
86UT3 TRIP & LOCKOUT BKR'S 52/UT3 & 52/UT3ST6
86UT4 TRIP & LOCKOUT BKR'S 52/UT4 & 52/UT4ST6
86ST5 TRIP & LOCKOUT BKR'S 52/ST5.52/UT1ST5.52/UT2ST5.52/GT25
86ST6 TRIP & LOCKOUT BKR'S 52/ST6.52/UT3ST6.52/UT4ST6.52/GT26
62UT1.62UT2.62UT3.62UT4.62ST5.62ST6.BKR.FAILURE TIMER
5.ALL BUSES- 6900V.,3Ø,60HZ.,1200A., EXCEPT AS NOTED.
6.THIS DRAWING SUPERSEDES W'HSE DWG.540F922.
7.FOR MORE DETAILED VERSION REFERENCE DWGS.,1410186, 1410187 AND 1360936
18
A RECORD OF THE ORIGINAL WITH INITIALS/SIGNATURES IS MAINTAINED IN CENTRAL ENGINEERING DOCUMENTATION FILE.
THE LAST PENCILED REVISION WAS 01
THE ORIGINAL TRACING FOR THIS DRAWING WAS PREPARED BY WESTINGHOUSE
THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS "CLASS A" ITEMS PER QAPD
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
V.MYERS 6/27/03
THIS REV IS NON-CLASS AS PER QAPD
UPDATED DWG AS PER CR-IP2-2002-11039
RELEASED FOR RECORD
P/N 69901-AF SL/VM
6/27/03
REPRODUCED
REPRODUCED
REPRODUCED
REVIEW
APPROVALS
TITLE: 6900 VOLT AC ONE LINE DIAGRAM
- UFSAR FIGURE No. 8.2-5
DRAWN BY A.K.
SCALE NONE
Con Edison
STATION INDIAN POINT#2
DWG. NO. A231592-18 0Z

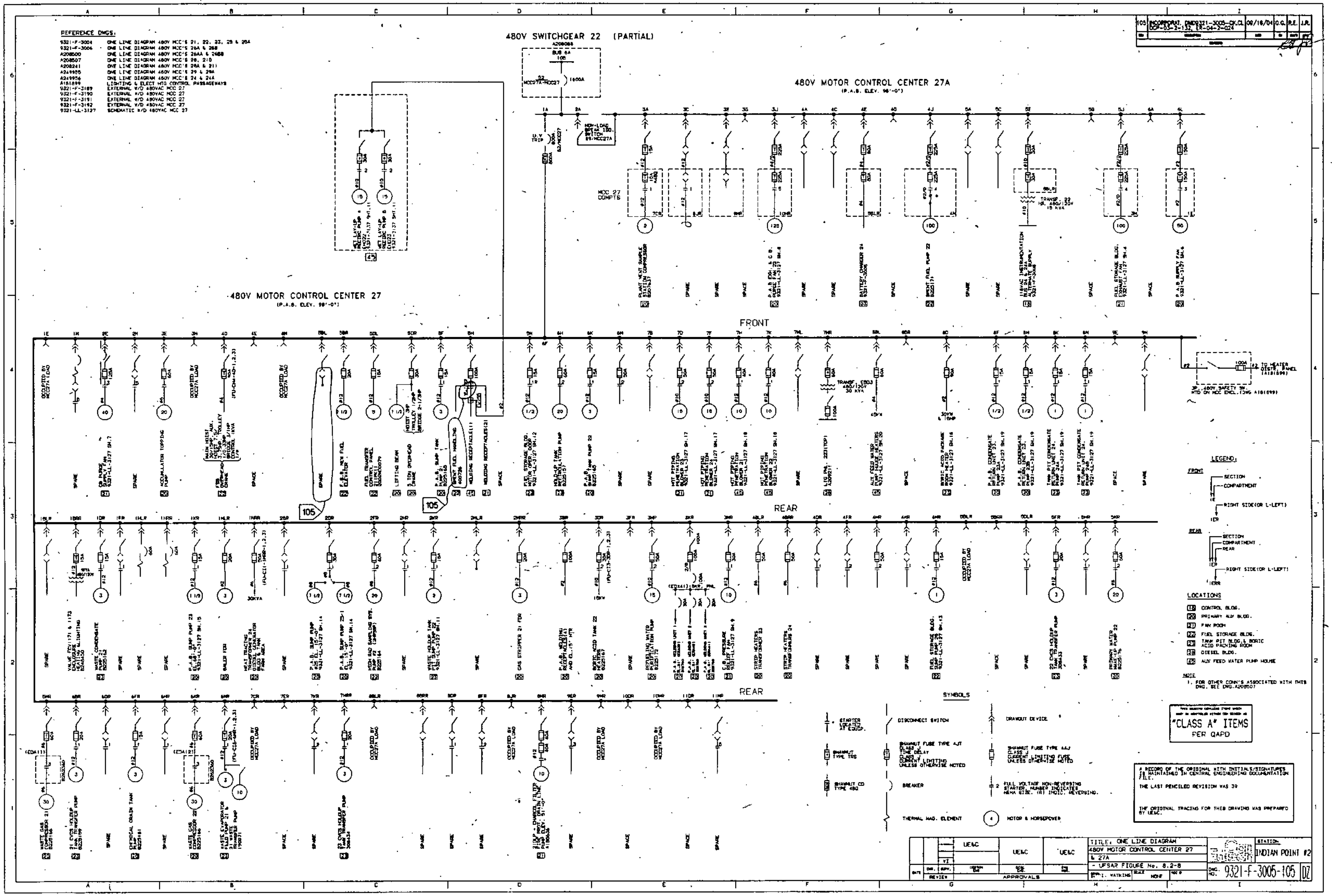


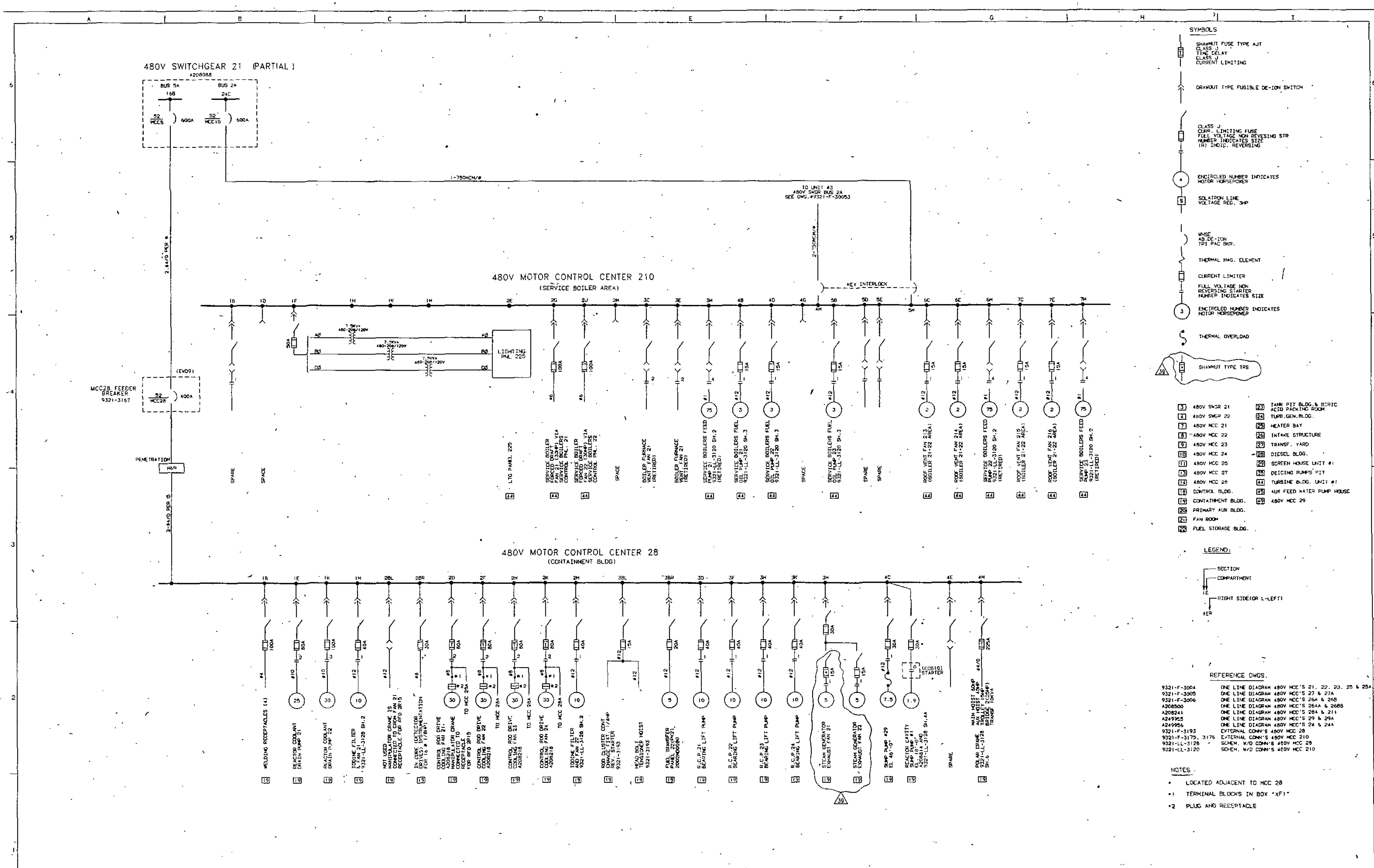
480V-SWITCHGEAR 22
(CONTROL BLDG ELEV. 15')
BUS 3A
BUS 6A
480V-SWITCHGEAR 21
(CONTROL BLDG ELEV. 15')
BUS 5A
BUS 2A
6.9KV SWITCHGEAR (A231592)
REFERENCE DWGS:
MAIN ONE LINE DIAG. ---------- A208377
6.9KV ONE LINE ---------- A231592
MAIN THREE LINE DIAG. ---------- 9321-F-3011
DIESEL GENERATOR & 480V THREE LINE ---------- 9321-F-3007
EXTERNAL W/D 480V SWGR #22 UNIT'S 1,2,3 ----- 9321-F-3168
EXTERNAL W/D 480V SWGR #22 UNIT'S 4,5,6 ----- 9321-F-3169
EXTERNAL W/D 480V SWGR #22 UNIT'S 7,8,9 ----- 9321-F-3170
EXTERNAL W/D 480V SWGR #22 UNIT'S 10,11,12 -- 9321-F-3171
EXTERNAL W/D 480V SWGR #22 UNIT 13 ---------- 9321-F-3172
EXTERNAL W/D 480V SWGR #21 UNIT'S 14,15,16 -- 9321-F-3163
EXTERNAL W/D 480V SWGR #21 UNIT'S 17,18,19 -- 9321-F-3164
EXTERNAL W/D 480V SWGR #21 UNIT'S 20,21,22 -- 9321-F-3165
EXTERNAL W/D 480V SWGR #21 UNIT'S 23,24,25 -- 9321-F-3166
EXTERNAL W/D 480V SWGR #21 UNIT 26 ---------- 9321-F-3167
INTERNAL W/D 480V SWGR #22 UNIT'S 1 & 2 ----- 204875
INTERNAL W/D 480V SWGR #22 UNIT'S 3 & 4 ----- 204882
INTERNAL W/D 480V SWGR #22 UNIT'S 5 & 6 ----- 204883
INTERNAL W/D 480V SWGR #22 UNIT'S 7 & 8 ----- 204869
INTERNAL W/D 480V SWGR #22 UNIT'S 9 & 10 ---- 204874
INTERNAL W/D 480V SWGR #22 UNIT'S 11 & 12 --- 204876
INTERNAL W/D 480V SWGR #22 UNIT 13 ---------- 204880
INTERNAL W/D 480V SWGR #21 UNIT'S 14 & 15 --- 204872
INTERNAL W/D 480V SWGR #21 UNIT'S 16 & 17 --- 204873
INTERNAL W/D 480V SWGR #21 UNIT'S 18 & 19 --- 204881
INTERNAL W/D 480V SWGR #21 UNIT'S 20 & 21 --- 204870
INTERNAL W/D 480V SWGR #21 UNIT'S 22 & 23 --- 204879
INTERNAL W/D 480V SWGR #21 UNIT'S 24 & 25 --- 204878
INTERNAL W/D 480V SWGR #21 UNIT 26 ---------- 204871
NOTE:
1. THIS DRAWING REPRODUCED FROM AND SUPERSEDES WHSE. CORP. DWG.#540F923
2 ALL BREAKERS ARE DB-50 ACB, FRAME SIZE 1600A, EXCEPT MARKED ■ -DB-75 ACB, FRAME SIZE 3000A (WHSE DWG 652C556 MICROFILM NO. 204877)
3. 17 LOCATED ON CONTROL ROOM PANEL
4. ▲ EMERGENCY CABLE CONNECTION AVAILABLE FROM IP1 SUBSTATION 12FD3 VIA TRANSFER SWITCHES EDC3 AND EDG1. SEE DRAWING B217913.
5. BREAKER RATINGS SHOWN ARE SENSOR RATINGS.
6. INDICATES PENETRATION
7. REFERENCE CLASSIFICATION DOCUMENT CL-04-014
"CLASS A" ITEMS
PER THE QAPD
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
41 INCORPORATED IP2-DRN-04-04392 ER-04-2-216 11/22/04 RM
1/15/93 E.TY
FRANCIS HOFFMAN
K.S. 04/20/87
A.K. FOR G.L. BLENKLE 04/20/87
REVIEW
APPROVALS
TITLE: ONE LINE DIAG. OF 480 VAC. SWGRS. 21 & 22, BUS 2A, 3A, 5A & 6A
- UFSAP FIGURE No. 8.2-6
DRAWN BY I. WATKINS
SCALE NONE
STATION INDIAN POINT #2
DWG. NO. A208088-41
07


480V SWITCHGEAR 21 (PARTIAL)
480V SWITCHGEAR 22 (PARTIAL)
480V MOTOR CONTROL CENTER 21
480V MOTOR CONTROL CENTER 23
480V MOTOR CONTROL CENTER 25
(ECE1)
480V MOTOR CONTROL CENTER 25A
480V MOTOR CONTROL CENTER 22
SYMBOLS
LEGEND:
REFERENCE DWGS:
9321-3005 ONE LINE DIAGRAM 480V MCC'S 27 & 27A
9321-3006 ONE LINE DIAGRAM 480V MCC'S 26A & 26B
A208500 ONE LINE DIAGRAM 480V MCC'S 26AA & 26BB
A208507 ONE LINE DIAGRAM 480V MCC'S 28, 210
A208241 ONE LINE DIAGRAM 480V MCC'S 28A & 211
A249955 ONE LINE DIAGRAM 480V MCC'S 29 & 29A
A249956 ONE LINE DIAGRAM 480V MCC'S 24 & 24A
9321-3177 EXT W/D 480VAC MCC21
9321-3178 EXT W/D 480VAC MCC21
9321-3179 EXT W/D 480VAC MCC22
9321-3180 EXT W/D 480VAC MCC22
9321-3181 EXT W/D 480VAC MCC23
9321-3182 EXT W/D 480VAC MCC23
9321-3184 EXT W/D 480VAC MCC25
9321-3121 SWD 480VAC MCC21
9321-3122 SWD 480VAC MCC22
9321-3123 SWD 480VAC MCC23
9321-3125 SWD 480VAC MCC25
NOTES:
1 CONNECTED LOAD 2-2 HP MTRS 3-3/4 HP MTRS AND 1-350VA, 480/120V, 1PH XFMR
MAX OPERATING LOAD 1-2HP MTR 1-3/4 HP MTR & 1-350VA 1PH XFMR
2 CONNECTED LOAD 1-1 HP MTR, 1-5 HP AND 1-350VA 480/120V 1PH XFMR
A RECORD OF THE ORIGINAL WITH INITIALS/SIGNATURES IS MAINTAINED IN CENTRAL ENGINEERING DOCUMENTATION FILE.
THE LAST PENCILED REVISION WAS 3:
THE ORIGINAL TRACING FOR THIS DRAWING WAS PREPARED BY UE&C.
"CLASS A" ITEMS
PER THE QAPD
84 INCORPORATED IP2-CRN-04-01377 ER-04-21649 06/30/04 DM
REVIEW
APPROVALS
UE&C
UE&C
UE&C
TITLE: ONE LINE DIAGRAM 480V MOTOR CONTROL CENTERS 21, 22, 23, 25 & 25A
- UFSAR FIGURE No. 8.2-7
T. WATKINS
SCALE NONE
Con Edison
STATION INDIAN POINT #2
DWG. NO. 9321-F-3004-84
DZ



480V SWITCHGEAR 21 (PARTIAL)
15
480V MOTOR CONTROL CENTER 24A
(TURB. GEN. BLDG. EL. 15'-0")
480V MOTOR CONTROL CENTER 24
(TURB. GEN. BLDG. EL. 15'-0")
2-750 MCM / PHASE
MCC 24 COMPTS
NON-LOAD BREAK ISO. SWITCH 89/MCC24A
SYMBOLS
DISCONNECT SWITCH
DRAWOUT DEVICE
FULL VOLTAGE NON-REVERSING STARTER LOCATED AT NEARBY EQUIPMENT
BREAKER
THERMAL MAG. ELEMENT
MOTOR & HORSEPOWER
FUSE NOT INSTALLED
MCC 24 COMPT. 2DL (TYPICAL)
LOCATIONS
18 CONTROL BLDG.
24 TURB.GEN.BLDG.
27 TRANSFORMER YARD
28 DIESEL GEN. BLDG.
REFERENCE DWGS:
9321-F-3004 ONE LINE DIAGRAM 480V MCC'S 21, 22, 23, 25 & 25A
9321-F-3005 ONE LINE DIAGRAM 480V MCC'S 27
9321-F-3006 ONE LINE DIAGRAM 480V MCC'S 26A & 26B
9321-F-3183 WIRING DIAGRAM MCC 24
A208500 ONE LINE DIAGRAM 480V MCC'S 26AA & 26BB
A208507 ONE LINE DIAGRAM 480V MCC'S 28, 29, 210
A208241 ONE LINE DIAGRAM 480V MCC'S 28A & 211
A249955 ONE LINE DIAGRAM 480V MCC'S 29 & 29A
LEGEND:
SECTION
COMPARTMENT
RIGHT SIDE(OR L-LEFT)
"CLASS A" ITEMS
PER CI-240-1
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
THIS REVISION IS NON-CLASS PER THE QAPD
UPDATED DWG. AS PER MOD. PROC. SNX-91-06681-M
DWG 208088-8N-00
ISSUED FOR RECORD
P/N 06681-91
MPH/ET
07-01-91
ET
B. SCHALL
07-01-91
G.BLENKLE
R.SAYA
REVIEW
APPROVALS
TITLE: ONE LINE DIAGRAM
480V MCC 24 & 24A
- UFSAR FIGURE No. 8.2-7A
K.FOLEY
SCALE NONE
Con Edison
STATION
INDIAN POINT #2
DWG. NO. A249956-15
DZ


480V SWITCHGEAR 22 (PARTIAL)
480V MOTOR CONTROL CENTER 27A
480V MOTOR CONTROL CENTER 27
FRONT
REAR
REAR
REFERENCE DWGS.
LEGEND
LOCATIONS
CONTROL BLDG.
FAN ROOM
FUEL STORAGE BLDG.
TANK PIT BLDG.& BORIC ACID PACKING ROOM
DIESEL BLDG.
AUX FEED WATER PUMP HOUSE
NOTE
1. FOR OTHER CONN'S ASSOCIATED WITH THIS DWG. SEE DWG.A208007
SYMBOLS
BREAKER
THERMAL MAG. ELEMENT
MOTOR & HORSEPOWER
FULL VOLTAGE NON-REVERSING STARTER, NUMBER INDICATES NEMA SIZE. (R) INDIC. REVERSING.
"CLASS A" ITEMS
PER QAPD
A RECORD OF THE ORIGINAL WITH INITIALS/SIGNATURES IS MAINTAINED IN CENTRAL ENGINEERING DOCUMENTATION FILE.
THE LAST PENCILED REVISION WAS 39
THE ORIGINAL TRACING FOR THIS DRAWING WAS PREPARED BY UE&C.
UE&C
UE&C
UE&C
REVIEW
APPROVALS
TITLE: ONE LINE DIAGRAM
480V MOTOR CONTROL CENTER 27
& 27A
- UFSAR FIGURE No. 8.2-8
I. WATKINS
SCALE NONE
STATION:
INDIAN POINT #2
DWG. NO. 9321-F-3005-105
DZ



39	INCORPORATED DRN-06-01547, TE 06-000711	5/18/06	DM
REV	DESCRIPTION	DATE	BY

TITLE: ONE LINE DIAGRAM,
480 VAC MCC'S 28 & 210

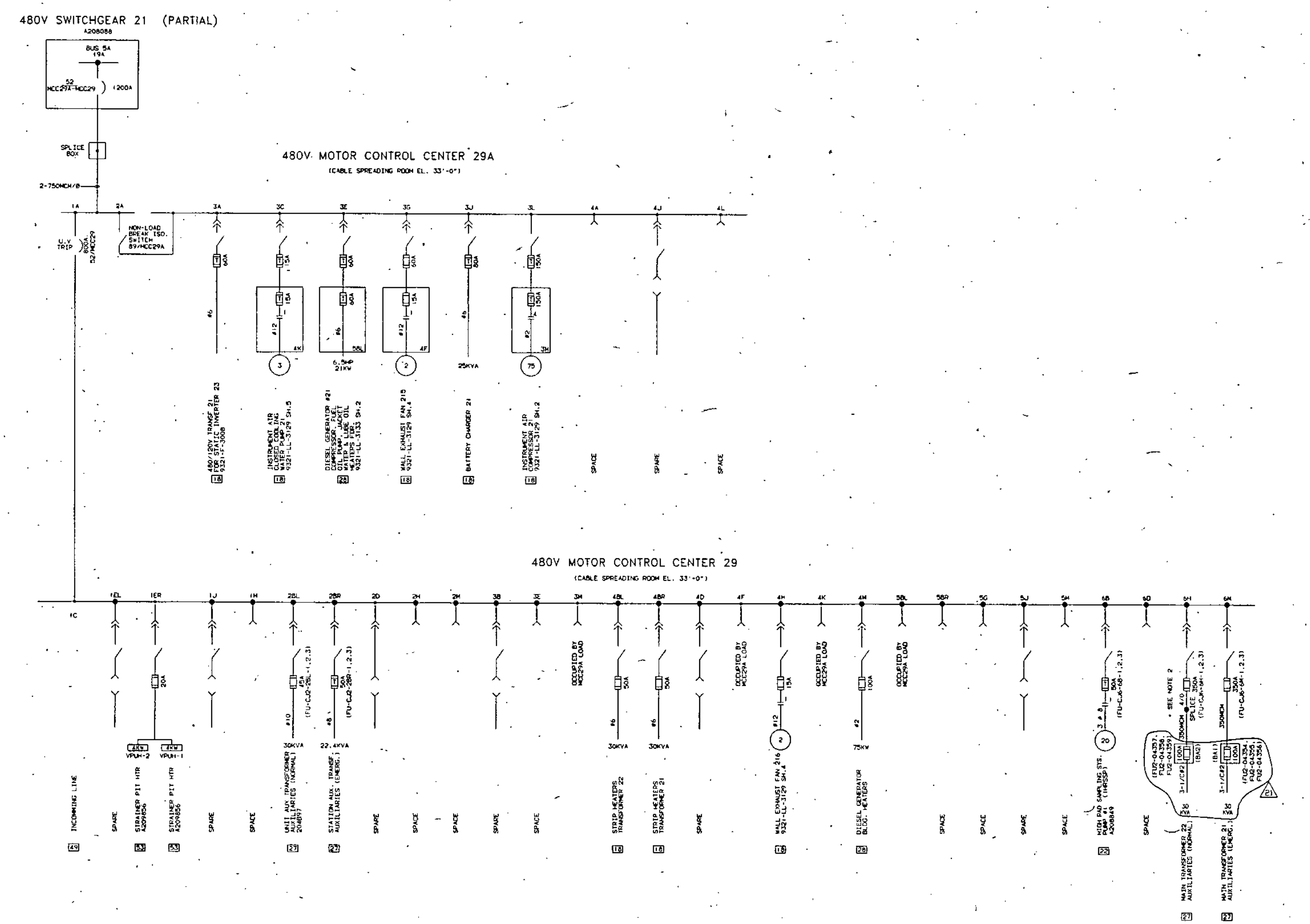
- UFSAR FIGURE No. 8.2-9

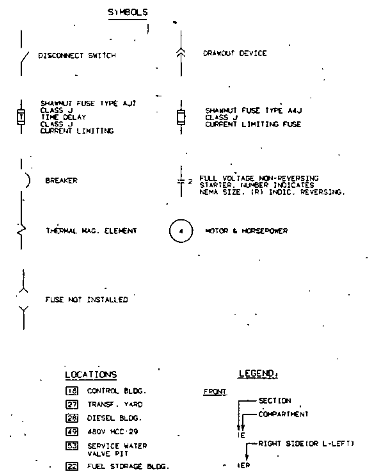
DRWN BY IW/TH — SCALE NONE

Entergy

STATION: INDIAN POINT #2

DWG. NO. A208507-39 DZ





REFERENCE DWGS:

9321-F-3004	ONE LINE DIAGRAM 480V MCC'S 21, 22, 23, 25 & 25A
9321-F-3005	ONE LINE DIAGRAM 480V MCC'S 27 & 27A
9321-F-3006	ONE LINE DIAGRAM 480V MCC'S 26A & 26B
A208500	ONE LINE DIAGRAM 480V MCC'S 26AA & 26BB
A208507	ONE LINE DIAGRAM 480V MCC'S 28, 210
A208241	ONE LINE DIAGRAM 480V MCC'S 28A & 211
A249956	ONE LINE DIAGRAM 480V MCC'S 24 & 24A
9321-F-3194	EXTERNAL W/D 480V MCC29
9321-LL-3129	SCHEMATIC W/D 480V MCC29

NOTES:

1. THIS DWG. SUPERSEDES IN PART CON EDISON (A208507)
2. FUTURE EXPANSION OF CIRCUIT 6H OF MCC29 IS LIMITED BY 200AMP DISCONNECT SWITCH
3. FOR FUSE INFORMATION SEE PLANT EQUIPMENT DATABASE

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
21	INCORPORATED DRN-06-00527, ER-04-2-059	5/17/06	GH	GM	VA

REVISIONS

TITLE: ONE LINE DIAGRAM, 480V AC MCC 29 & 29A

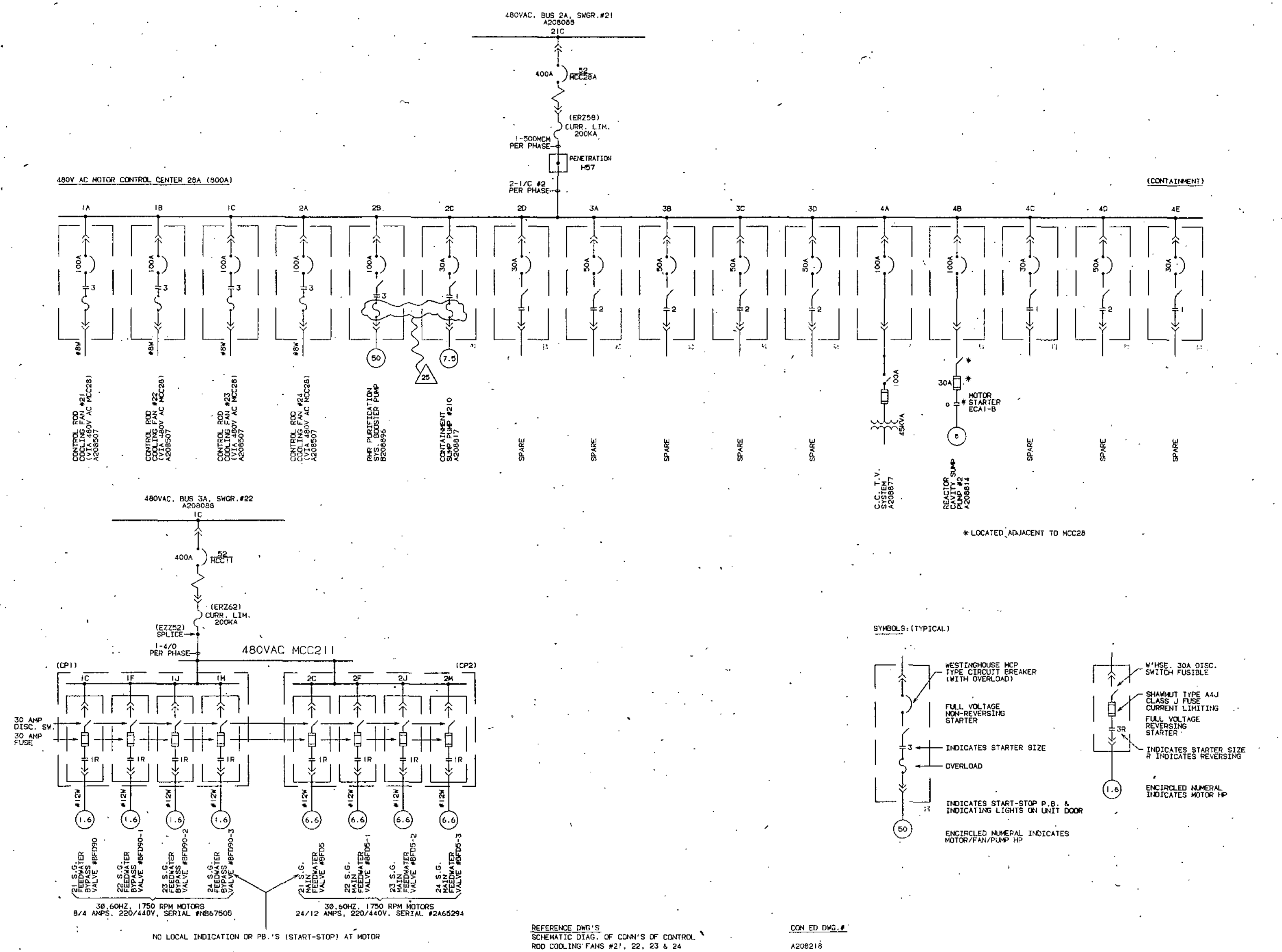
- UFSAR FIGURE No. 8.2-9A

DRWN BY K.FOLEY | SCALE NONE | REC'D

Entergy

STATION INDIAN POINT #2

DWG. NO. A249955-21 DZ



REFERENCE DWG'S	CON ED DWG.#
SCHEMATIC DIAG. OF CONN'S OF CONTROL ROD COOLING FANS #21, 22, 23 & 24	A208218
DIAG. OF INT. CONN'S OF STARTERS & PHYSICAL LAYOUT & ELECTRICAL SPEC'S OF 480VAC MCC 28A	A208217
ONE LINE DIAG. OF 480VAC. 3 PHASE. 60HZ. POWER SUPPLY	A208088
DIAGRAM OF EXTERNAL CONN'S OF 480V MCC# 28A	A208216
	U.E.&C. DWG.#
FEEDWATER SYSTEM BY-PASS VALVES (SHTS. #2,6,15) AND SCHEMATIC W/D OF CONN'S FOR MCC211 (SHTS. #9 THRU 9G)	9321-LL-3601
SCHEMATIC DIAG. OF 480V SWITCHGEAR #21 (SHTS. #3,11)	9321-LL-3117

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

REV	DESCRIPTION	DATE	BY	CHK'D	APP.
25	INCORPORATED DRN-06-00542 ER-IP2-06-10796	2/13/06	JS	RL	N/A

REVISIONS

TITLE: SINGLE LINE DIA OF 480 VAC MCC 28A AND 211

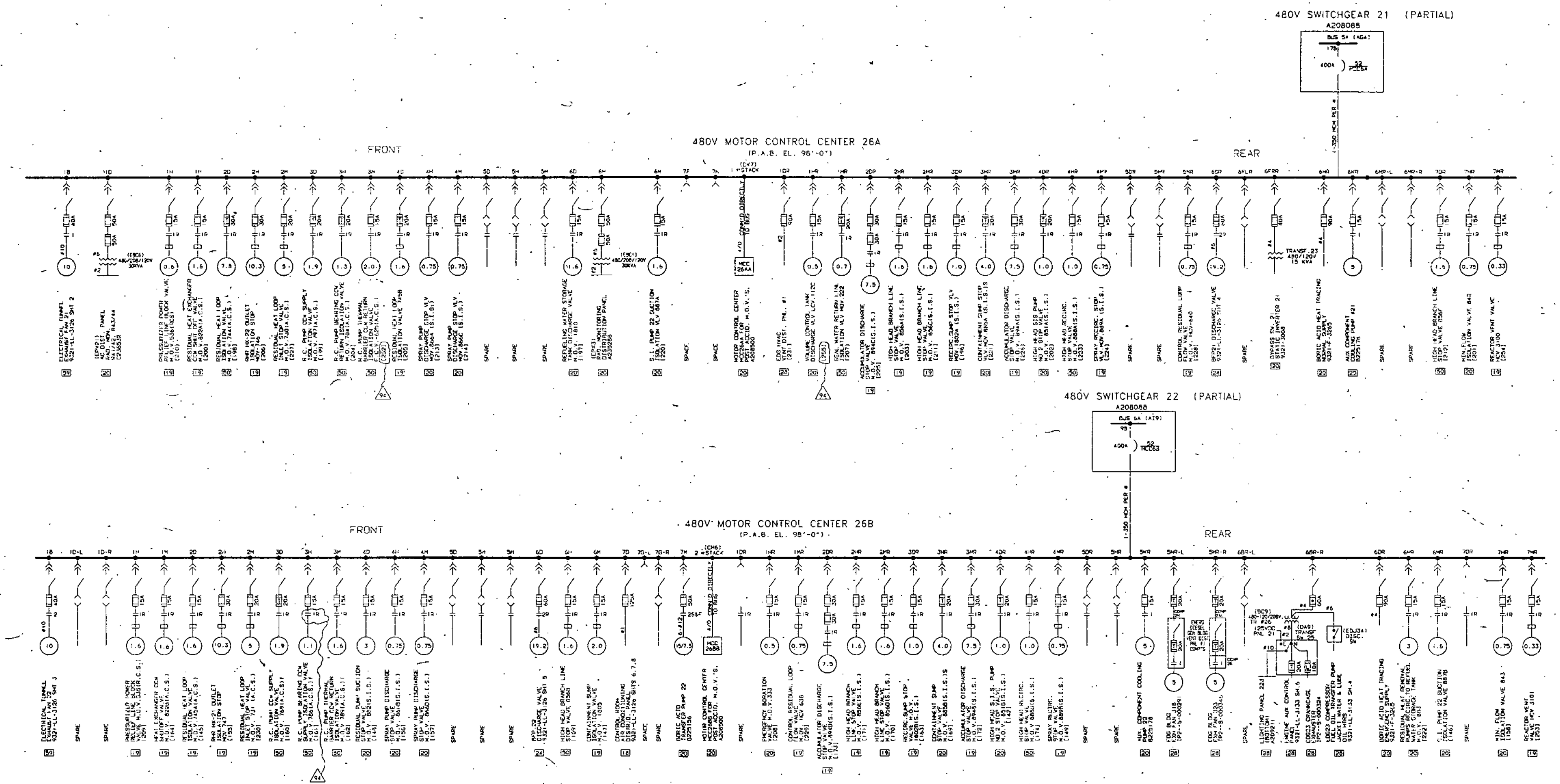
- UFSAR FIGURE No. 8.2-10

DRWN BY T. WATKINS | SCALE NONE | REC'D

Entergy

STATION INDIAN POINT #2

DWG. NO. A208241-25 DZ



SYMBOLS

DISCONNECT SWITCH

DRAWOUT DEVICE

SHAWMUT TYPE TRS

SHAWMUT FUSE TYPE AJT CLASS J TIME DELAY CURRENT LIMITING FUSE

SHAWMUT FUSE TYPE A4J CLASS J CURRENT LIMITING FUSE

BUSSMAN TYPE LPN-RK

BREAKER

FULL VOLTAGE NON-REVERSING STARTER. NUMBER INDICATES NEMA SIZE. (R) INDIC. REVERSING. (S&F) INDICATE SLOW & FAST.

THERMAL MAG. ELEMENT

MOTOR & HORSEPOWER

S	SAFETY INJECTION SIGNAL
T	TRIP OR CLOSE ON HIGH CONTAINM
SIS	SAFETY INJECTION SYSTEM
ACS	AUXILIARY COOLANT SYSTEM
RCS	REACTOR COOLANT SYSTEM

17	CONTROL ROOM PANEL
18	CONTROL BUILDING
19	CONTAINMENT BUILDING
20	PRIMARY AUX. BUILDING
24	TURBINE GENERATOR BUILDING
26	INTAKE STRUCTURE
28	DIESEL GENERATOR BUILDING
50	PENETRATION TUNNEL
59	ELECTRICAL TUNNEL

NOTES:

1. PANELS ARE TYPE NEB
2. ALL FEEDERS SHALL BE #12 UNLESS OTHERWISE INDICATED
3. ALL REFERENCES TO DWG. NUMBERS IN ( ) REPRESENT THE SCHEMATIC WIRING DIAGRAM (SWD#).

REFERENCE DWGS:

9321-F-3004	ONE LINE DIAGRAM 480V MCC'S 21, 22, 23, 25 & 25A
9321-F-3005	ONE LINE DIAGRAM 480V MCC 27
A208500	ONE LINE DIAGRAM 480V MCC'S 26AA & 26BB
A208507	ONE LINE DIAGRAM 480V MCC'S 28, 210
A208241	ONE LINE DIAGRAM 480V MCC'S 28A & 211
A249955	ONE LINE DIAGRAM 480V MCC'S 29 & 29A
A249956	ONE LINE DIAGRAM 480V MCC'S 24 & 24A
9321-F-3185	EXTERNAL WIRING DIAGRAM MCC 26A
9321-F-3186	EXTERNAL WIRING DIAGRAM MCC 26A
9321-F-3187	EXTERNAL WIRING DIAGRAM MCC 26B
9321-F-3188	EXTERNAL WIRING DIAGRAM MCC 26B
9321-F-3208	EXTERNAL WIRING DIAGRAM MCC'S 26A & 26B
9321-LL-3126	SCHEMATIC WIRING DIAGRAM MCC'S 26A & 26B

LEGEND:

FRONT

SECTION

COMPARTMENT

1E

RIGHT SIDE(OR L-LEFT)

1E-R

REAR

SECTION

COMPARTMENT

REAR

1ER

RIGHT SIDE(OR L-LEFT)

1ER-R

Original
e-mod
1-5
P88

REV	DESCRIPTION	DATE	BY	CHK'D	APP
94	INCORPORATED DRN-06-00345 ER IP2-05-27301	4/24/06	JS	RL	N/A

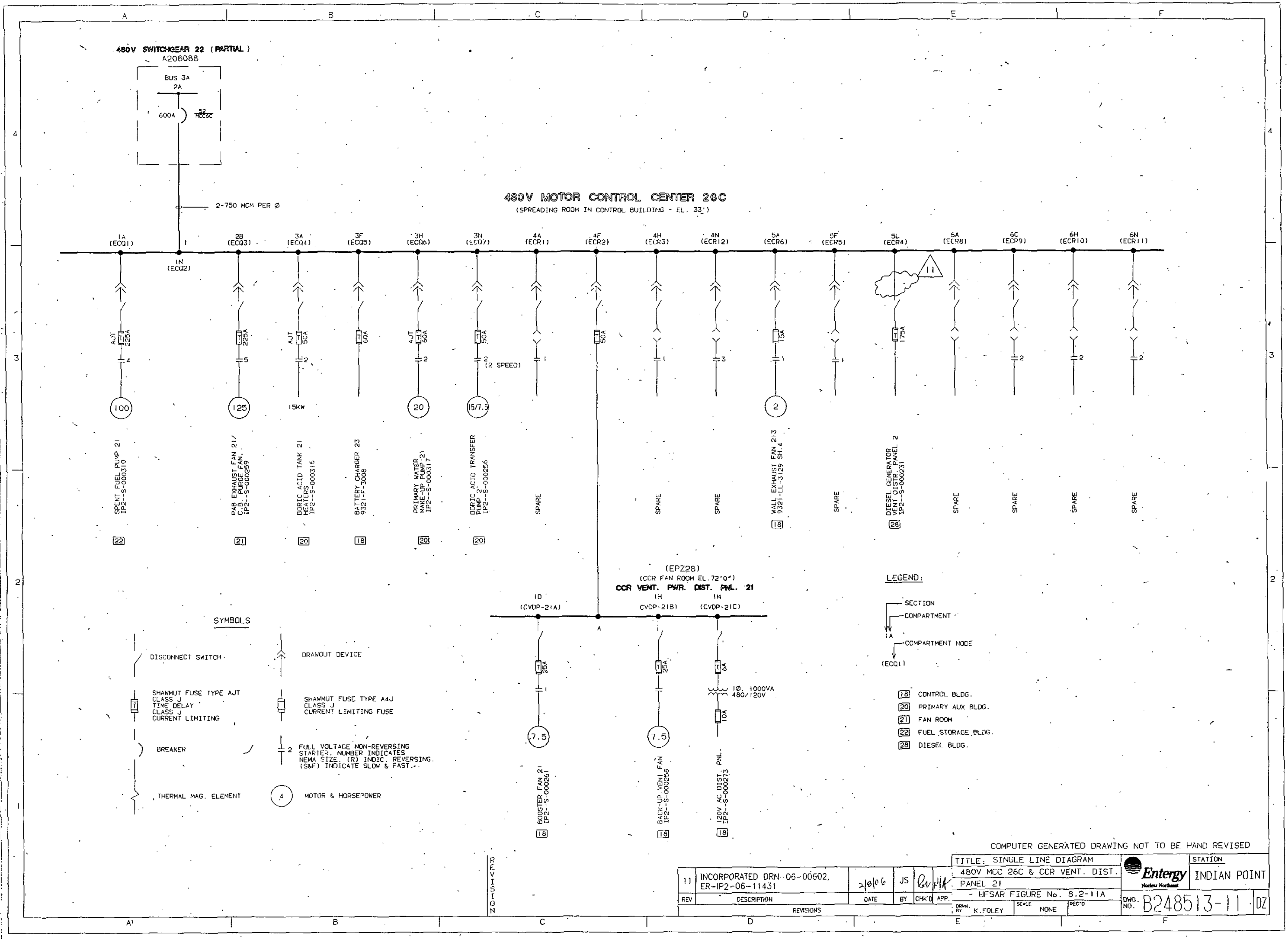
REVISIONS

INDIAN POINT ENERGY CENTER - UNIT 2

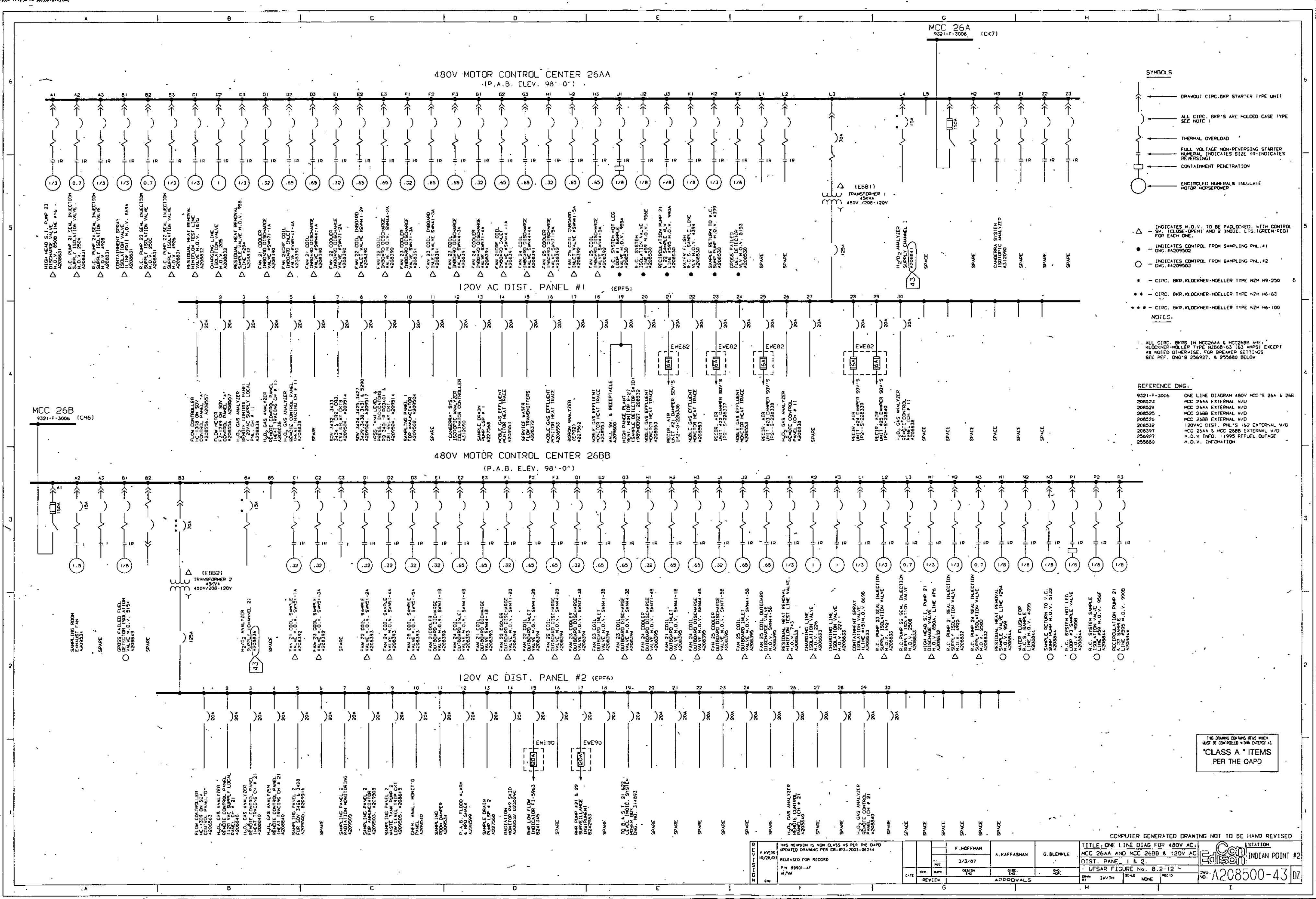
SINGLE LINE DIAGRAM
480V MCC 26A AND 26B

Entergy

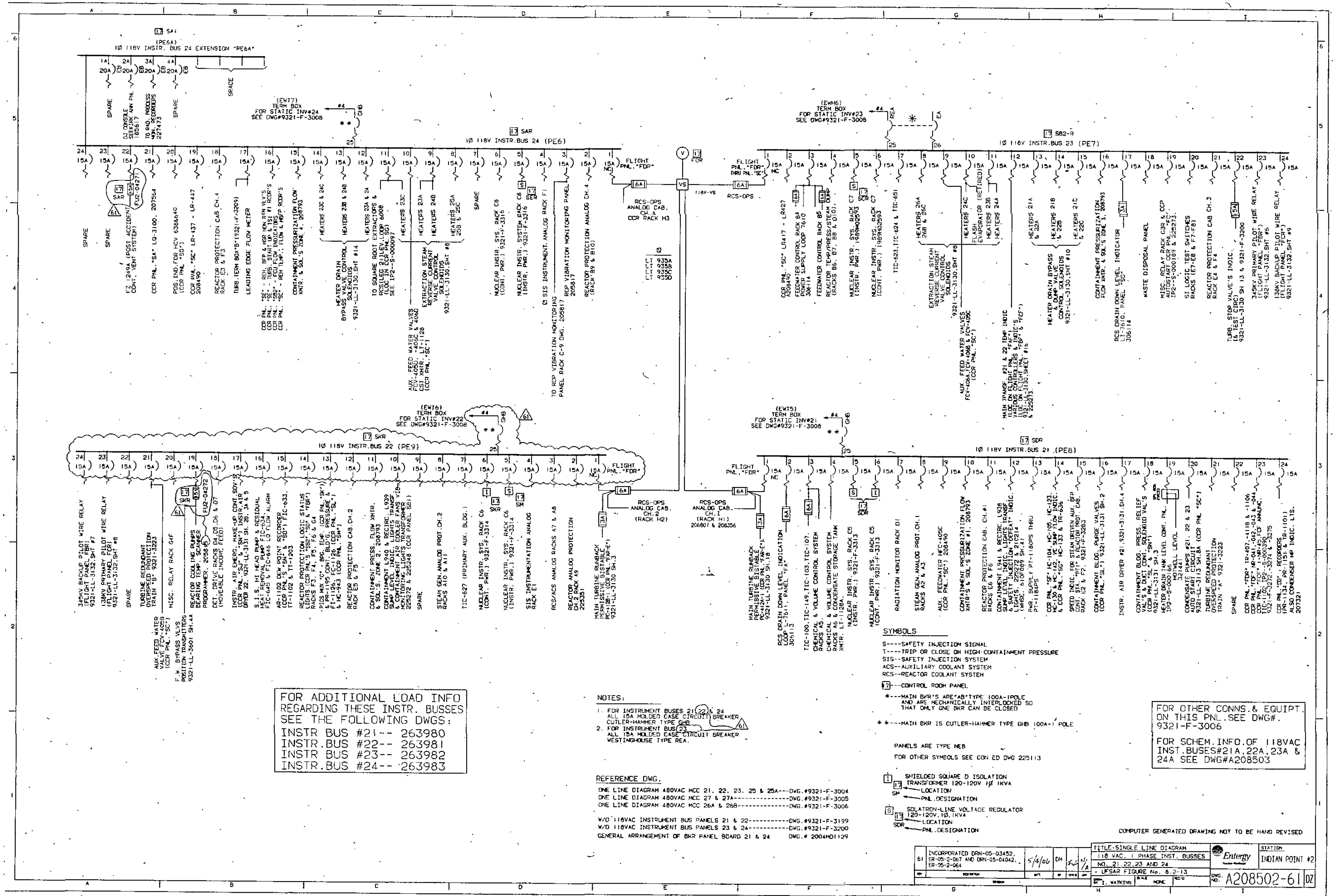
DWG NO. 9321-F-3006-94 DZ

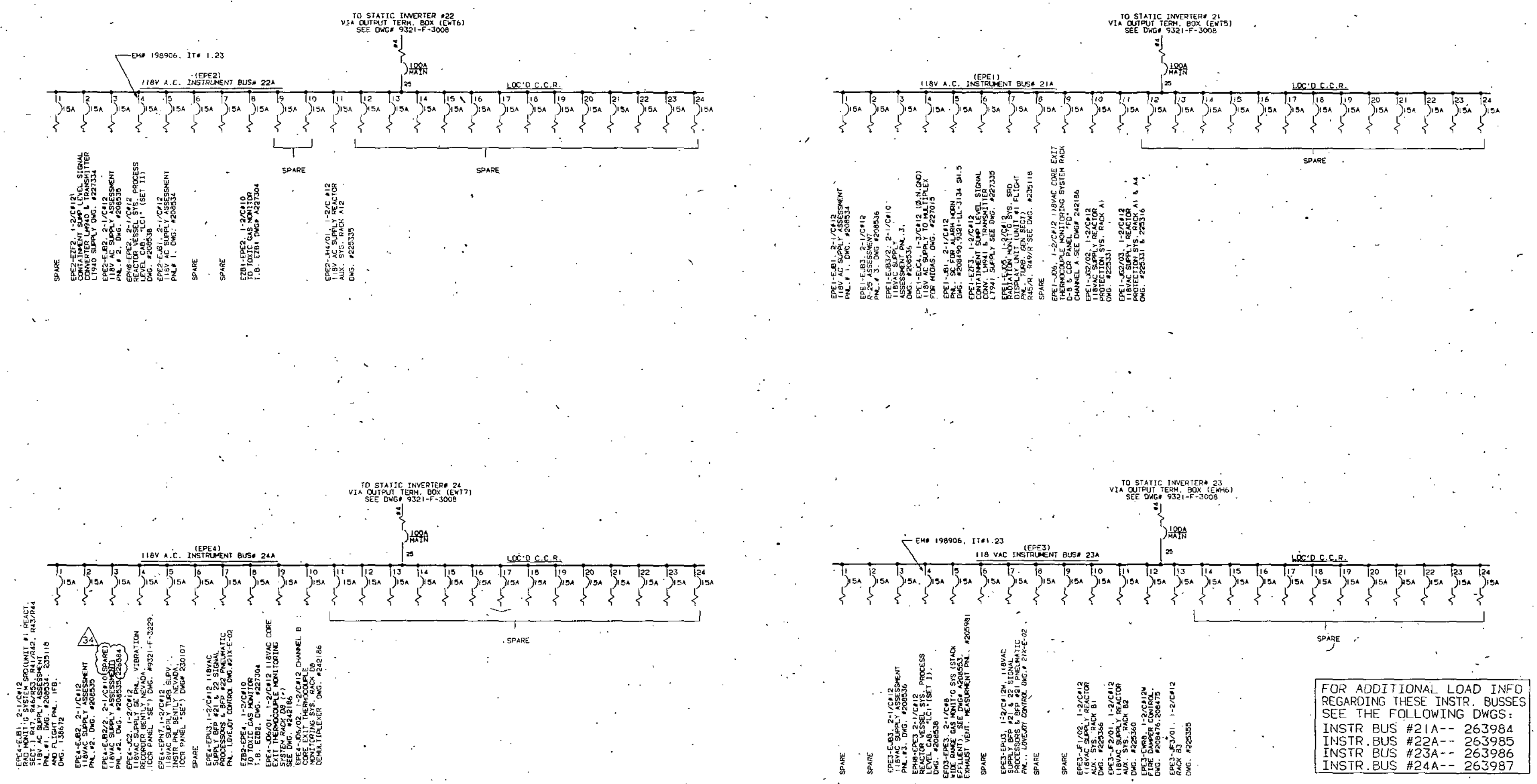


480V SWITCHGEAR 22 (PARTIAL)
A208088
BUS 3A
2A
600A
52 MCC6C
2-750 MCM PER Ø
480V MOTOR CONTROL CENTER 26C
(SPREADING ROOM IN CONTROL BUILDING - EL. 33')
1A (ECQ1)
1N (ECQ2)
2B (ECQ3)
3A (ECQ4)
3F (ECQ5)
3H (ECQ6)
3N (ECQ7)
4A (ECR1)
4F (ECR2)
4H (ECR3)
4N (ECR12)
5A (ECR6)
5F (ECR5)
5L (ECR4)
6A (ECR8)
6C (ECR9)
6H (ECR10)
6N (ECR11)
AJT 225A
AJT 50A
AJT 60A
225A
60A
50A
15A
175A
(2 SPEED)
15KW
100
125
20
15/7.5
2
SPENT FUEL PUMP 21 IP2--S-000310
PAB EXHAUST FAN 21/ C.B. PURGE FAN. IP2--S-000259
BORIC ACID TANK 21 HEATERS IP2--S-000316
BATTERY CHARGER 23 9321-F-3008
PRIMARY WATER MAKE-UP PUMP 21 IP2--S-000317
BORIC ACID TRANSFER PUMP 21 IP2--S-000256
SPARE
WALL EXHAUST FAN 213 9321-LL-3129 SH.4
DIESEL GENERATOR VENT. DISTR. PANEL 2 IP2--S-000231
22
21
20
18
28
11
(EPZ28)
(CCR FAN ROOM EL.72'0")
CCR VENT. PWR. DIST. PNL. 21
1D (CVDP-21A)
1H CVDP-21B)
1M (CVDP-21C)
1A
25A
6A
1Ø, 1000VA 480/120V
10A
7.5
BOOSTER FAN 21 IP2--S-000261
BACK-UP VENT FAN IP2--S-000258
120V AC DIST. PNL. IP2--S-000273
SYMBOLS
DISCONNECT SWITCH
DRAWOUT DEVICE
SHAWMUT FUSE TYPE AJT CLASS J TIME DELAY CLASS J CURRENT LIMITING
SHAWMUT FUSE TYPE A4J CLASS J CURRENT LIMITING FUSE
BREAKER
FULL VOLTAGE NON-REVERSING STARTER. NUMBER INDICATES NEMA SIZE. (R) INDIC. REVERSING. (S&F) INDICATE SLOW & FAST.
THERMAL MAG. ELEMENT
MOTOR & HORSEPOWER
LEGEND:
SECTION
COMPARTMENT
COMPARTMENT NODE
(ECQ1)
18 CONTROL BLDG.
20 PRIMARY AUX BLDG.
21 FAN ROOM
22 FUEL STORAGE BLDG.
28 DIESEL BLDG.
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
11 INCORPORATED DRN-06-00602, ER-IP2-06-11431 2/8/06 JS
REV DESCRIPTION DATE BY CHK'D APP.
REVISIONS
REVISION
TITLE: SINGLE LINE DIAGRAM 480V MCC 26C & CCR VENT. DIST. PANEL 21 - UFSAR FIGURE No. 8.2-11A
DRWN. BY K.FOLEY SCALE NONE REC'D
Entergy Nuclear Northeast
STATION INDIAN POINT
DWG. NO. B248513-11 DZ



MCC 26A
9321-F-3006 (CK7)
480V MOTOR CONTROL CENTER 26AA
(P.A.B. ELEV. 98'-0")
120V AC DIST. PANEL #1 (EPF5)
MCC 26B
9321-F-3006 (CH6)
480V MOTOR CONTROL CENTER 26BB
(P.A.B. ELEV. 98'-0")
120V AC DIST. PANEL #2 (EPF6)
SYMBOLS
NOTES:
REFERENCE DWG:
"CLASS A" ITEMS
PER THE QAPD
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
THIS REVISION IS NON CLASS AS PER THE QAPD
UPDATED DRAWING PER CR-IP2-2003-06244
RELEASED FOR RECORD
P.N. 69901-AF
V.MYERS 10/28/03
F.HOFFMAN
3/3/87
A.KAFFASHAN
G.BLENKLE
REVIEW
APPROVALS
TITLE: ONE LINE DIAG FOR 480V AC:
MCC 26AA AND MCC 26BB & 120V AC
DIST. PANEL 1 & 2.
- UFSAR FIGURE No. 8.2-12 -
SCALE NONE
STATION
INDIAN POINT #2
DWG. NO. A208500-43


1Ø 118V INSTR. BUS 24 (PE6)
1Ø 118V INSTR. BUS 23 (PE7)
1Ø 118V INSTR. BUS 22 (PE9)
1Ø 118V INSTR. BUS 21 (PE8)
1Ø 118V INSTR. BUS 24 EXTENSION "PE6A"
FOR ADDITIONAL LOAD INFO
REGARDING THESE INSTR. BUSSES
SEE THE FOLLOWING DWGS:
INSTR.BUS #21-- 263980
INSTR.BUS #22-- 263981
INSTR.BUS #23-- 263982
INSTR.BUS #24-- 263983
NOTES:
1. FOR INSTRUMENT BUSES 21, 22 & 24
ALL 15A MOLDED CASE CIRCUIT BREAKER
CUTLER-HAMMER TYPE GHB
2. FOR INSTRUMENT BUS 23
ALL 15A MOLDED CASE CIRCUIT BREAKER
WESTINGHOUSE TYPE REA.
REFERENCE DWG.
ONE LINE DIAGRAM 480VAC MCC 21, 22, 23, 25 & 25A---DWG.#9321-F-3004
ONE LINE DIAGRAM 480VAC MCC 27 & 27A---------------DWG.#9321-F-3005
ONE LINE DIAGRAM 480VAC MCC 26A & 26B--------------DWG.#9321-F-3006
W/D 118VAC INSTRUMENT BUS PANELS 21 & 22-----------DWG.#9321-F-3199
W/D 118VAC INSTRUMENT BUS PANELS 23 & 24-----------DWG.#9321-F-3200
GENERAL ARRANGEMENT OF BKR PANEL BOARD 21 & 24 DWG.# 2004MD1129
SYMBOLS
S----SAFETY INJECTION SIGNAL
T----TRIP OR CLOSE ON HIGH CONTAINMENT PRESSURE
SIS--SAFETY INJECTION SYSTEM
ACS--AUXILIARY COOLANT SYSTEM
RCS--REACTOR COOLANT SYSTEM
17---CONTROL ROOM PANEL
*---MAIN BKR'S ARE "AB" TYPE 100A-1POLE AND ARE MECHANICALLY INTERLOCKED SO THAT ONLY ONE BKR CAN BE CLOSED
**---MAIN BKR IS CUTLER-HAMMER TYPE GHB 100A-1 POLE
PANELS ARE TYPE NEB
FOR OTHER SYMBOLS SEE CON ED DWG 225113
SHIELDED SQUARE D ISOLATION TRANSFORMER 120-120V 1Ø 1KVA
LOCATION
PNL.DESIGNATION
SOLATRON-LINE VOLTAGE REGULATOR 120-120V, 1Ø, 1KVA
LOCATION
PNL.DESIGNATION
FOR OTHER CONNS.& EQUIPT. ON THIS PNL.SEE DWG#. 9321-F-3006
FOR SCHEM.INFO.OF 118VAC INST.BUSES#21A,22A,23A & 24A SEE DWG#A208503
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
61 INCORPORATED DRN-05-03452, ER-05-2-067 AND DRN-05-04042, ER-05-2-064 5/4/06 DM N/A
TITLE-SINGLE LINE DIAGRAM
118 VAC. 1 PHASE INST. BUSSES
NO. 21,22,23 AND 24
- UFSAR FIGURE No. 8.2-13
I. WATKINS
SCALE NONE
Entergy
STATION
INDIAN POINT #2
DWG. NO. A208502-61
DZ



(*) CONTINUED FROM CIRCUIT #9 ABOVE
JD6-JA4/02 TO T-SAT (CH.B) NR46, NR47,
PR403, TR433 PANEL FDF. DWG. 9321-F-3274

REFERENCE DWGS.:

SINGLE LINE DIAG. D-C SYSTEM ________ 9321-F-3008
D/C FOR INSTR. BUSES 21A, 22A, 23A& 24A ________ 208504

NOTES:

1- FOR SCHEM. INFO. OF 118V AC INSTR. BUSES# 21,22,23&24 SEE DWG. #208502

FOR ADDITIONAL LOAD INFO
REGARDING THESE INSTR. BUSSES
SEE THE FOLLOWING DWGS:
INSTR BUS #21A-- 263984
INSTR.BUS #22A-- 263985
INSTR.BUS #23A-- 263986
INSTR.BUS #24A-- 263987

34	INCORPORATED DRN-06-01615 ER-04-2-234	6/21/06	RML		
REV	DESCRIPTION	DATE	BY	CHK'D	APP

04/13/88 | CP | BS | FRANCIS HOFFMAN 12/08/87 | K.S. 04/20/87 | A.K. FOR G.L. BLENKLE 04/20/87
DATE | REVIEW | APPROVALS

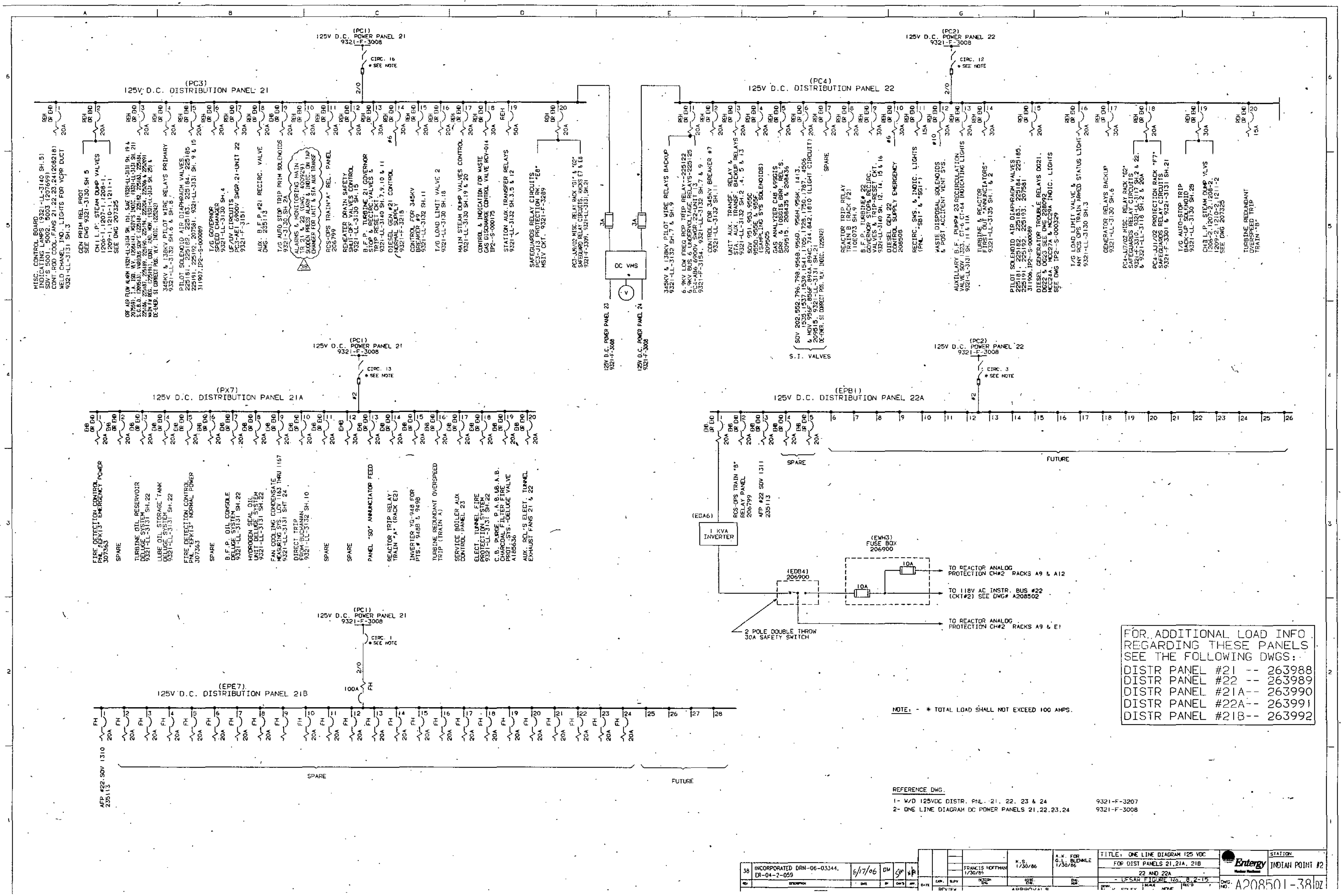
TITLE: SCHEM DIA OF 118 VAC INST BUSES 21A,22A,23A AND 24A (LOCATED IN CCR) - UFSAR FIGURE No. 8.2-14

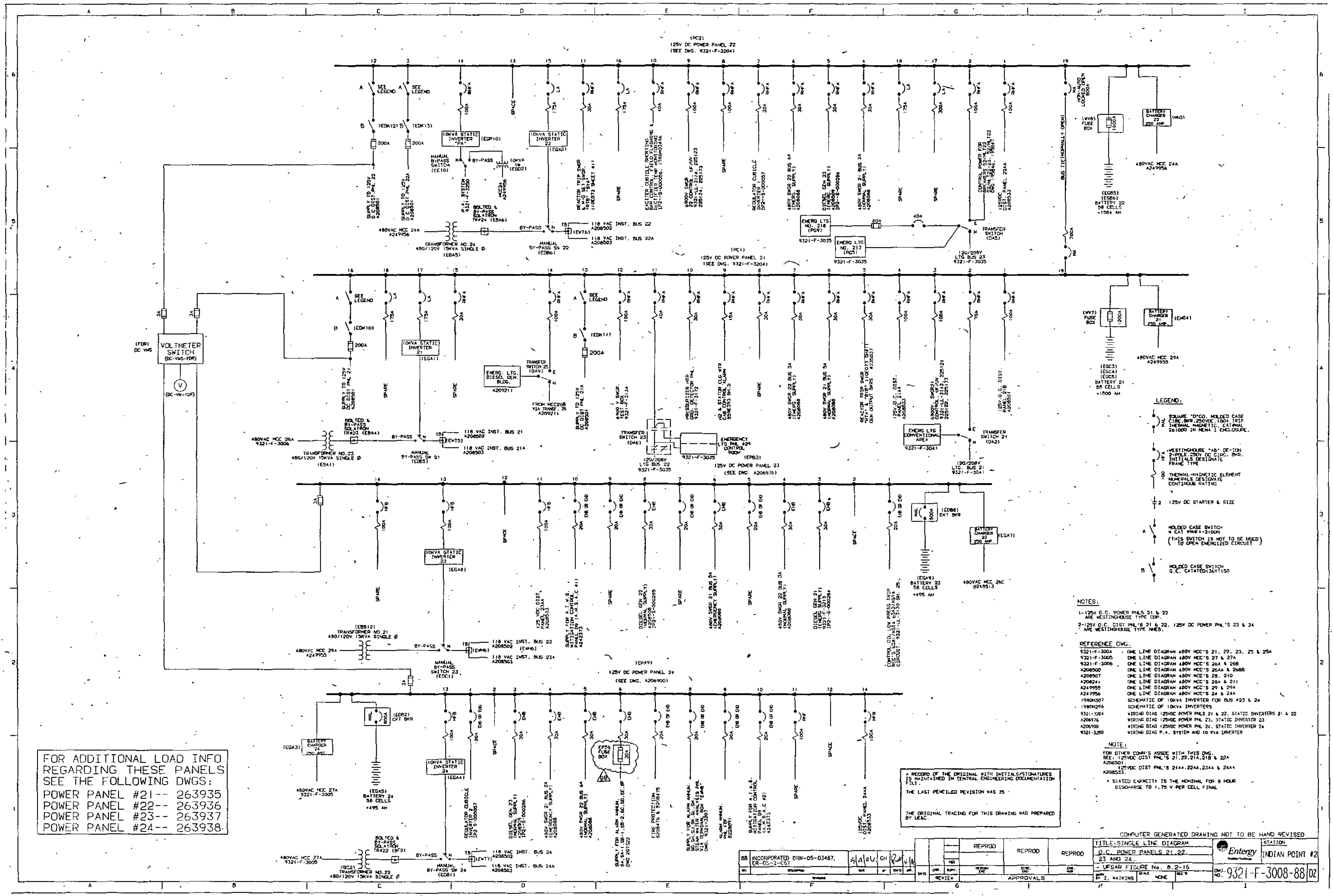
DRAWN BY Z. WATKINS | SCALE NONE

Entergy

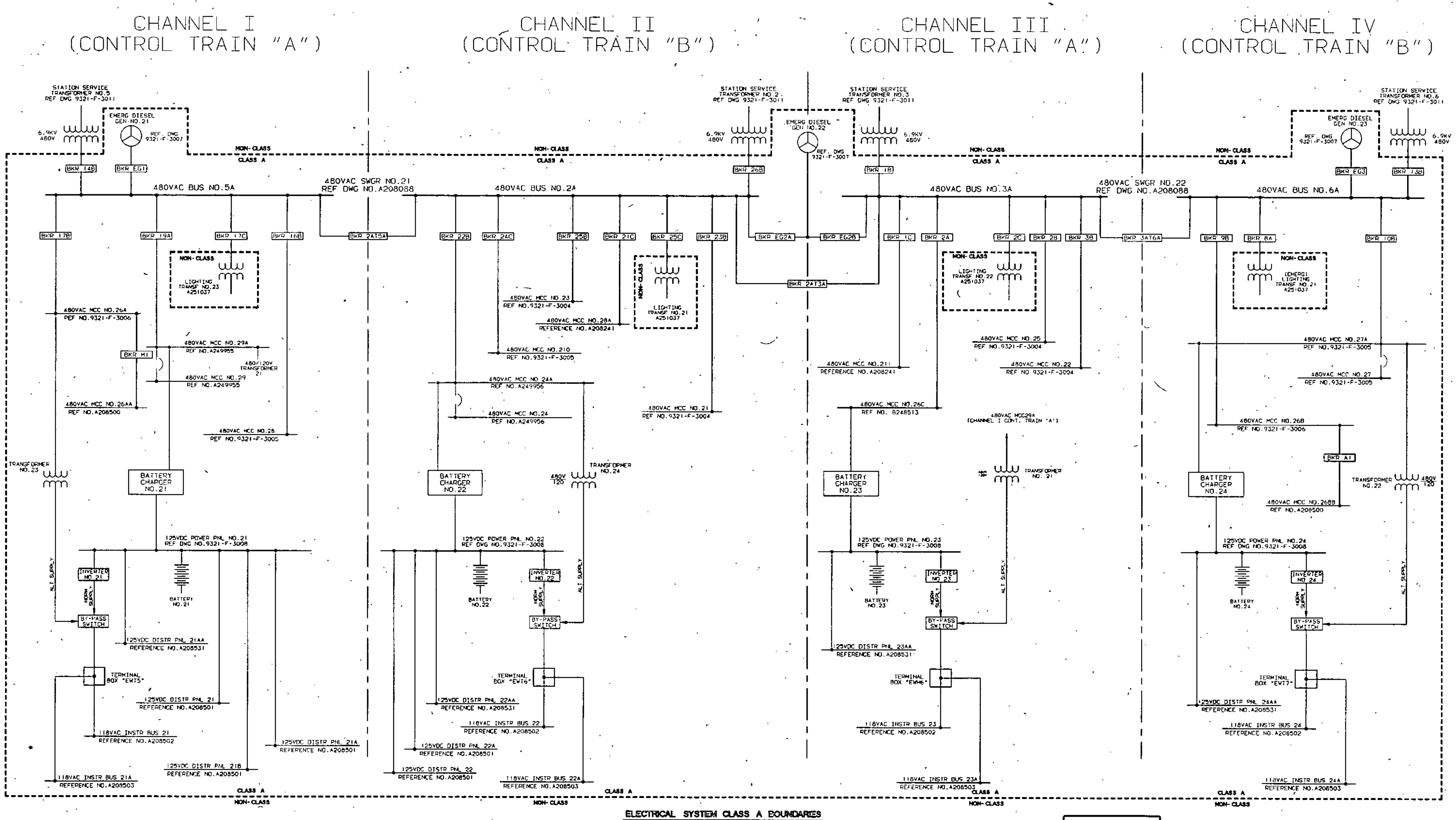
STATION: INDIAN POINT #2

DWG. NO. A208503-34 DZ


(PC1) 125V D.C. POWER PANEL 21 9321-F-3008
CIRC. 16 * SEE NOTE
(PC3) 125V D.C. DISTRIBUTION PANEL 21
(PC2) 125V D.C. POWER PANEL 22 9321-F-3008
CIRC. 12 * SEE NOTE
(PC4) 125V D.C. DISTRIBUTION PANEL 22
DC VMS
125V D.C. POWER PANEL 23 9321-F-3008
125V D.C. POWER PANEL 24 9321-F-3008
S.I. VALVES
(PC1) 125V D.C. POWER PANEL 21 9321-F-3008
CIRC. 13 * SEE NOTE
(PX7) 125V D.C. DISTRIBUTION PANEL 21A
(PC2) 125V D.C. POWER PANEL 22 9321-F-3008
CIRC. 3 * SEE NOTE
(EPB1) 125V D.C. DISTRIBUTION PANEL 22A
SPARE
FUTURE
(EGA6) 1 KVA INVERTER
(EWH3) FUSE BOX 206900
(EDB4) 206900
TO REACTOR ANALOG PROTECTION CH#2 RACKS A9 & A12
TO 118V AC INSTR. BUS #22 (CKT#2) SEE DWG# A208502
TO REACTOR ANALOG PROTECTION CH#2 RACKS A9 & E1
2 POLE DOUBLE THROW 30A SAFETY SWITCH
(PC1) 125V D.C. POWER PANEL 21 9321-F-3008
CIRC. 1 * SEE NOTE
(EPE7) 125V D.C. DISTRIBUTION PANEL 21B
AFP #22 SOV 1310 235113
SPARE
FUTURE
FOR ADDITIONAL LOAD INFO REGARDING THESE PANELS SEE THE FOLLOWING DWGS:
DISTR PANEL #21 -- 263988
DISTR PANEL #22 -- 263989
DISTR PANEL #21A-- 263990
DISTR PANEL #22A-- 263991
DISTR PANEL #21B-- 263992
NOTE: - * TOTAL LOAD SHALL NOT EXCEED 100 AMPS.
REFERENCE DWG.
1- W/D 125VDC DISTR. PNL. 21, 22, 23 & 24 9321-F-3207
2- ONE LINE DIAGRAM DC POWER PANELS 21,22,23,24 9321-F-3008
38 INCORPORATED DRN-06-03344, ER-04-2-059 6/17/06
TITLE: ONE LINE DIAGRAM 125 VDC FOR DIST PANELS 21,21A, 21B 22 AND 22A
UFSAR FIGURE No. 8.2-15
Entergy
STATION INDIAN POINT #2
A208501-38



(PC2)
125V DC POWER PANEL 22
(SEE DWG. 9321-F-3204)
(PC1)
125V DC POWER PANEL 21
(SEE DWG. 9321-F-3204)
(EPB3)
125V DC POWER PANEL 23
(SEE DWG. A206976)
(EPA9)
125V DC POWER PANEL 24
(SEE DWG. A206900)
VOLTMETER SWITCH
LEGEND:
MOLDED CASE SWITCH
(THIS SWITCH IS NOT TO BE USED TO OPEN ENERGIZED CIRCUIT)
MOLDED CASE SWITCH G.E. CAT#TED136YT150
NOTES:
1-125V D.C. POWER PNLS 21 & 22 ARE WESTINGHOUSE TYPE CDP.
2-125V D.C. DIST PNL'S 21 & 22, 125V DC POWER PNL'S 23 & 24 ARE WESTINGHOUSE TYPE NHEB.
REFERENCE DWG.
9321-F-3004 - ONE LINE DIAGRAM 480V MCC'S 21, 22, 23, 25 & 25A
9321-F-3005 ONE LINE DIAGRAM 480V MCC'S 27 & 27A
9321-F-3006 ONE LINE DIAGRAM 480V MCC'S 26A & 26B
A208500 ONE LINE DIAGRAM 480V MCC'S 26AA & 26BB
A208507 ONE LINE DIAGRAM 480V MCC'S 28, 210
A208241 ONE LINE DIAGRAM 480V MCC'S 28A & 211
A249955 ONE LINE DIAGRAM 480V MCC'S 29 & 29A
A249956 ONE LINE DIAGRAM 480V MCC'S 24 & 24A
1980M307 SCHEMATIC OF 10KVA INVERTER FOR BUS #23 & 24
1980M296 SCHEMATIC OF 10KVA INVERTERS
9321-3204 WIRING DIAG 125VDC POWER PNLS 21 & 22, STATIC INVERTERS 21 & 22
A206976 WIRING DIAG 125VDC POWER PNL 23, STATIC INVERTER 23
A206900 WIRING DIAG 125VDC POWER PNL 24, STATIC INVERTER 24
9321-3250 WIRING DIAG P.A. SYSTEM AND 10 KVA INVERTER
NOTE:
FOR OTHER CONN'S ASSOC WITH THIS DWG.
SEE: 125VDC DIST PNL'S 21,22,21A,21B & 22A A206501.
125VDC DIST PNL'S 21AA,22AA,23AA & 24AA A208533.
* STATED CAPACITY IS THE NOMINAL FOR 8 HOUR DISCHARGE TO 1.75 V PER CELL FINAL
FOR ADDITIONAL LOAD INFO
REGARDING THESE PANELS
SEE THE FOLLOWING DWGS:
POWER PANEL #21-- 263935
POWER PANEL #22-- 263936
POWER PANEL #23-- 263937
POWER PANEL #24-- 263938
A RECORD OF THE ORIGINAL WITH INITIALS/SIGNATURES IS MAINTAINED IN CENTRAL ENGINEERING DOCUMENTATION FILE.
THE LAST PENCILED REVISION WAS 35
THE ORIGINAL TRACING FOR THIS DRAWING WAS PREPARED BY UE&C.
COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED
88 INCORPORATED DRN-05-03487, ER-05-2-C67
REPROD
REPROD
REPROD
REVIEW
APPROVALS
TITLE: SINGLE LINE DIAGRAM
D.C. POWER PANELS 21,22, 23 AND 24.
- UFSAR FIGURE No. 8.2-16
DWN BY I. WATKINS
SCALE NONE
Entergy
STATION
INDIAN POINT #2
DWG. NO. 9321-F-3008-88
DZ



NOTE

THIS DWG IS INTENDED TO SHOW "SAFEGUARD CHANNELING AND CONTROL TRAIN DEVELOPMENT" ONLY. FOR MORE INFORMATION CONCERNING SPECIFIC BKR POSITION, SIZING AND EQUIPMENT RATING SEE REFERENCE DWG AS INDICATED.

CLASS A ITEMS
PER CI-240-1

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

Revision	THIS REVISION IS NON-CLASS PER THE QAPD. REVISED DRAWING PER CPS #200104889 P/N 69901-AF J.H./A.L. 05/18/01
	STRATUS ENGINEERING
Approvals	J. LOWNEY 10/01/80; P. DUGGAN 10/07/80; ROBERT SAYA 10/07/80
Title	SINGLE LINE DIAG OF UNIT SAFEGUARD CHANNELING AND CONTROL TRAIN DEVELOPMENT - UFSAR FIGURE No. 8.2-17
Station	INDIAN POINT
Dwg No.	A208376-11
Scale	NONE
By	I. WATKINS 11/24/80

11

INDIAN POINT | A208761 | CABLE TRAY SEPARATION FUNCTIONS / ROUTING

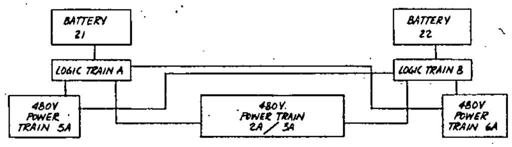
CHANNEL / CONTROL TRAIN / POWER TRAIN SEPARATION DESIGNATIONS	FUNCTION	PHYSICAL ROUTING DESIGNATIONS (SEE NOTE 5)
I (RED) II (WHITE) III (BLUE) IV (YELLOW)	120 VOLT A.C. INSTRUMENT BUS FEEDS AND ANALOG & DIGITAL SIGNAL OUTPUTS ASSOCIATED WITH 120 VOLT A.C. INSTRUMENT BUSES 21, 22, 23 & 24 RESPECTIVELY	J1, J2, J3, J4 } FOR PROTECTION SYSTEM CIRCUITRY. CHANNEL / ROUTING ASSOCIATIONS ARE FIXED (I IN J1, II IN J2, ETC.) SPECIFIC EXCEPTIONS (e.g. A CHANNEL I CIRCUIT ROUTED IN A J2, J3 OR J4 TRAY) MUST BE APPROVED BY E.E. AND WILL ONLY BE PERMITTED FOR NON-SAFETY (NON-IE) FUNCTIONS ALL PORTIONS OF A PARTICULAR INSTRUMENT LOOP SHALL BE ROUTED IN THE SAME CHANNEL.
CONTROL TRAIN A (RED) CONTROL TRAIN B (WHITE)	125 VOLT D.C. CONTROL AND SMALL POWER FEEDS ASSOCIATED WITH 125 VOLT D.C. BATTERIES 21 AND 22 RESPECTIVELY * * IN THE ORIGINAL PLANT DESIGN ONLY TWO BATTERIES (BATTERIES 21 & 22) EXISTED AND REDUNDANT (TRAIN A AND TRAIN B) CONTROL SIGNALS ARE SENT TO EQUIPMENT IN EACH POWER TRAIN. THIS PERMITS THE 3RD POWER TRAIN ASSOCIATED WITH 480 VOLT BUSES 2A AND 3A TO MEET SINGLE FAILURE CRITERIA	K1 Δ K2 Δ Δ A THIRD D ROUTING EXISTS FOR SELECTED CIRCUITS REQUIRING 3 TRAIN SEPARATION
480 VOLT M.C.C. POWER TRAIN 5A AND ASSOCIATED 120 VOLT A.C. (M.C.C. CONTROL TRANSFORMER) SMALL POWER & CONTROL CIRCUITS (RED)	480 V. M.C.C. POWER & CONTROL	K1 SEE NOTES #1 & 4 — FIXED ASSOCIATION (i.e. 5A IN K1) FOR ALL IE CIRCUITS. SPECIFIC EXCEPTIONS (e.g. A NON IE M.C.C. POWER OR CONTROL FEED FROM BUS 5A ROUTED IN K2 MUST BE APPROVED BY E.E.
480 VOLT M.C.C. POWER TRAIN 6A (YELLOW)	" " " " "	K2 SEE NOTES #1 & 4
480 VOLT M.C.C. POWER TRAIN 2A (WHITE)	" " " " "	VARIOUS "D" CHANNELS SEE NOTES #1 & 4
480 VOLT M.C.C. POWER TRAIN 3A (BLUE)	" " " " "	VARIOUS "D" CHANNELS SEE NOTES #1 & 4
CONTROL TRAIN C (BLUE)	125 VOLT D.C. CONTROL AND SMALL POWER FEEDS ASSOCIATED WITH 125 VOLT D.C. BATTERY 23 (ADDED AFTER PLANT START-UP)	K3D AND VARIOUS "D" CHANNELS SEE NOTES #1 & 4
CONTROL TRAIN D (YELLOW)	125 VOLT D.C. CONTROL AND SMALL POWER FEEDS ASSOCIATED WITH 125 VOLT D.C. BATTERY 24 (ADDED AFTER PLANT START-UP)	SEE NOTES #1 & 4
HEAVY POWER (480 VOLT & 125 VOLT D.C.) BUS 5A (RED) BUS 6A (YELLOW) BUS 2A (WHITE) BUS 3A (BLUE)	480 VOLT HEAVY POWER & 125 VOLT HEAVY POWER ASSOCIATED WITH 480V BUS 5A/BATTERY 21, 480 VOLT BUSES 2A & 3A/BATTERY 22 AND 480 VOLT BUS 6A RESPECTIVELY	C4 (ASSOCIATED WITH BUS 5A) C3 (ASSOCIATED WITH BUS 6A) C6 (ASSOCIATED WITH BUS 2A) C5 (ASSOCIATED WITH BUS 3A) SEE NOTE #4
D.C. CONTROL FEEDS FOR DIESELS	SPECIAL ROUTINGS ASSOCIATED WITH D.C. CONTROL FEEDS FOR DIESELS 21, 22 & 23 RESPECTIVELY THROUGH THE CONTROL TUNNEL	F(21) DC FEED FROM BATTERY 21 F(22) " " " " 22 F(23) " " " " 23 F(24) " " " " 24

NOTES:

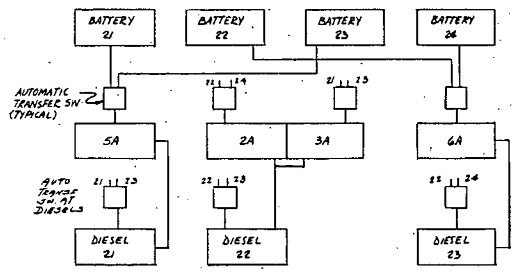
1. K1 AND K2 ARE THE KEY BASIC 480 VOLT SMALL POWER AND 120 VOLT M.C.C. ROUTING DESIGNATIONS. THESE DESIGNATIONS HAVE BEEN FURTHER EXPANDED IN THE RACEWAY SYSTEM TO PROVIDE ADDITIONAL ROUTING OF FUNCTIONAL INFORMATION

ROUTINGS ADAPTABLE WITH K1 480/120 VAC EXCEPT AS NOTED	ROUTING ASSOCIATED WITH K2D BATTERY 22	ROUTING ASSOCIATED WITH K3D BATTERY 23	ROUTINGS ADAPTABLE WITH K2	ROUTING OR FUNCTIONS
K1 (RED)	—	— ▲	K2 (YELLOW)	GENERAL DESIGNATIONS USED IN MOST AREAS OF THE PLANT AND FOR MOST FUNCTIONS ▲ D-D400 - EXISTS FOR THIRD TRAIN SEPARATION IN ORIGINAL PLANT DESIGN
K1A (RED)	—	— *	K2A (YELLOW)	ROUTING BETWEEN DIESEL AND CONTROL BUILDING * D-D200 - EXISTS FOR THREE TRAIN SEPARATION IN ORIGINAL PLANT DESIGN
K1B (RED)	—	—	K2B (YELLOW)	ROUTING BETWEEN P.A.B. & CONTAINMENT FOR MCC. 26A & M.C.C. 26B
K1AA (RED)	—	—	K2BB (YELLOW)	POWER AND CONTROL ASSOCIATED WITH MOTOR CONTROL CENTERS 26AA AND 26BB RESPECTIVELY WHICH WERE ADDED AS PART OF "THREE MILE ISLAND" PLANT MODIFICATIONS
125 V DC K1 LOGIC & CONTROL POWER K1D (RED)	125 V DC K2 LOGIC & CONTROL POWER K2D (WHITE)	125 V DC. K1 LOGIC ONLY K3D (BLUE)	125 V DC K2 LOGIC ONLY K4D (YELLOW)	BATTERY 21 & 22 LOGIC SIGNALS AND CONTROL POWER (K1 & K2) RESPECTIVELY AND NEW ROUTINGS FOR 125 VOLT D.C. BATTERIES 21 THROUGH 24 RESPECTIVELY FOR CIRCUITS WHICH WERE ADDED AS PART OF "THREE MILE ISLAND" PLANT MODIFICATIONS SEE NOTES 3 & 4

2. "CIRCUIT TYPE" DESIGNATIONS ARE USED TO FUNCTIONALLY DESCRIBE THE PURPOSE OF A CIRCUIT. THESE ARE PURELY FUNCTIONAL DESCRIPTIONS AND SHOULD NOT BE CONFUSED WITH PHYSICAL ROUTING DESIGNATIONS. LIST TABLE OR CIRCUIT TYPE DESIGNATIONS - FROM CABLE SCHEDULE



480 VOLT SYSTEM CHANNELIZATION OF LOGIC SIGNALS



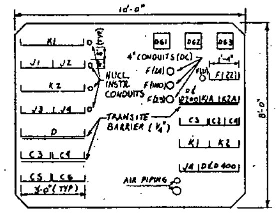
480 VOLT SYSTEM CHANNELIZATION OF D.C. CONTROL POWER

NOTES CONTINUED:

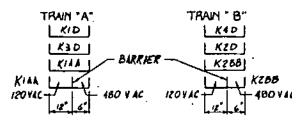
4. IN THE ORIGINAL PLANT DESIGN SEPARATION WAS SET UP ON A CIRCUIT BY CIRCUIT BASIS RATHER THAN A "UNITIZED" FIXED "BUS TO ROUTING CHANNEL" ASSOCIATION (e.g. C1 ≡ BUS 5A) SINGLE FAILURE IS MET FOR THESE CASES BECAUSE OF THE FLEXIBILITY OF REDUNDANT TRAIN A AND B LOGIC AND CONTROL SIGNALS TO EACH BUS (i.e. LOSS OF ONE TRAY MAY FAIL A CONTAINMENT SPRAY PUMP ON ONE BUS AND AN SI PUMP ON ANOTHER BUS BUT CONTROL FROM ONE OR THE TWO D.C. SYSTEMS WILL STILL BE AVAILABLE TO BOTH BUSES. IN ALL FUTURE MODIFICATIONS THE "UNITIZED" BUS / ROUTING ASSOCIATIONS AS SHOWN ON THE TABLE ARE PREFERRED. EXCEPTIONS WILL BE PERMITTED FOR NON-IE EQUIPMENT WHERE NECESSARY TO MAINTAIN THE ORIGINAL PLANT CRITERIA OF MINIMIZING PHYSICAL CROSSOVERS IN THE CABLE RACE-WAY SYSTEM.

5. AS ESTABLISHED BY THE ORIGINAL PLANT DESIGN CRITERIA AND SUBSEQUENT MODIFICATIONS ALL NON CLASS IE CIRCUITS (POWER, CONTROL AND INSTRUMENTATION) WERE ROUTED IN TRAYS OR CONDUITS CONVENIENT TO THE TERMINATION POINTS. THIS WAS ACCOMPLISHED BY ROUTING CABLE IN ANY SAFTEY GRADE CHANNELS AND AS SUCH TREATED AS AN "ASSOCIATED CIRCUIT". THEREFORE NO "TRAY HOPPING" WAS PERMITTED AND ONCE A NON IE CIRCUIT WAS ASSIGNED TO A SAFEGUARD ROUTING CHANNEL IT MUST HAVE REMAINED IN THAT CHANNEL THROUGHOUT THE WHOLE RUN.

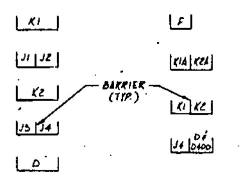
6. ALL CABLES IN RACEWAYS SHALL MEET THE LATEST CON EDISON SPECIFICATION EO-13 AND BE QUALIFIED TO IEEE 383. COMMERCIAL GRADE CABLE AND IMC CONDUIT IS ONLY PERMITTED FOR LIGHTING, RECEPTACLES, AND OTHER SERVICES NOT ASSOCIATED WITH PLANT PROCESS SYSTEMS (M.O. BUILDING, TSC, RESPIRATOR FACILITY, PLANT OFFICES ETC.). ALL TERMINAL BLOCKS INSTALLED SHALL BE QUALIFIED TO IEEE 323 AND 344 TO ASSURE THEIR AVAILABILITY FOR FUTURE CLASS "A"/CLASS "IE" TERMINATIONS.



TYPICAL SECTION CABLE TUNNEL



TYPICAL SECTION ON EL. 98'-0" P.A.B.



TYPICAL SECTION CABLE SPREADING ROOM

THIS DRAWING CONTAINS ITEMS WHICH MUST BE CONTROLLED WITHIN CON EDISON AS "CLASS A" ITEMS PER CI-240-1

Con Edison clean energy

REVISIONS

0	THIS REV. IS CLASS "A" AS PER CI-240-1 MOD. PROC. & ESG 80-2-21 RELEASED FOR INFORMATION P.N. 90049-50 2/4/81
1	THIS REV. IS CLASS "A" AS PER CI-240-1. ADDED NOTE #6. MOD. PROC. ESG 80-2-21 REL. FOR INFO. P/N 90049-50
2	THIS REVISION IS CLASS "A" PER CI-240-1 UPDATED DWG TO SHOW WORK OF REV. 0 & 1 MOD. PROC. ESG-80-2-21 RELEASED FOR AS CONSTRUCTED P.N. 90049-50 6-8-84
03	V1 4/16/99 THIS REVISION IS NON-CLASS PER CI-240-1 UPDATED DRAWING TO INCLUDE UFSAR FIGURE No. IN TITLE P/N 6991I-NP RELEASED FOR RECORD DLA/4/16/99

STRATUS ENGINEERING

A 208761-3

CONSOLIDATED EDISON CO. OF NEW YORK, INC.

STATION LOCATION INDIAN POINT

CABLE TRAY SEPARATION FUNCTIONS & ROUTING DESIGNATIONS - OUTLINE - UFSAR FIGURE No. 8.2-18

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APPROVALS

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EXHIBIT 3

CHAPTER 8

ELECTRICAL SYSTEMS

8.1 DESIGN BASES

The main generator feeds electrical power at 22 kV through an isolated phase bus to two half-sized main power transformers. The bulk of the power required for station auxiliaries during normal operation is supplied by an auxiliary transformer connected to the isolated phase bus. This practice has been proven highly satisfactory. Deviations from past practices are reflected in the provisions for stand-by or emergency power which have been included to further ensure the continuity of electrical power for critical loads.

The function of the Auxiliary Electrical System is to provide reliable power to those auxiliaries required during any normal or emergency mode of plant operation.

The design of the system is such that sufficient independence or isolation between the various sources of electrical power is provided in order to guard against concurrent loss of all auxiliary power.

The Authority is engaged in a program to perform a detailed evaluation of safety related electrical equipment to ensure that the equipment will perform their safety functions during and following the postulated accident. The scope of the program includes safety concerns and qualification criteria.

The General Design Criteria presented and discussed in this section are those which were in effect at the time when Indian Point 3 was designed and constructed. These general design criteria, which formed the bases for the Indian Point 3 design, were published by the Atomic Energy Commission in the Federal Register of July 11, 1967, and subsequently made a part of 10 CFR 50.

The Authority has completed a study of compliance with 10 CFR Parts 20 and 50 in accordance with some of the provisions of the Commission's Confirmatory Order of February 11, 1980. The detailed results of the evaluation of compliance of Indian Point 3 with the General Design Criteria presently established by the Nuclear Regulatory Commission (NRC) in 10 CFR 50 Appendix A, were submitted to NRC on August 11, 1980, and approved by the Commission on January 19, 1982. These results are presented in Section 1.3.

An additional diesel generator has been installed to comply with 10 CFR 50 Appendix "R" requirements; also supports compliance with Station Blackout (SBO). The diesel generator is considered non-safety related.

8.1.1 Principal Design Criteria

Performance Standards

Criterion: Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that will enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design. (GDC 2 of 7/11/67)

All electrical systems and components vital to plant safety, including the emergency diesel generators, are designed as Class I so that their integrity is not impaired by the maximum potential earthquake, wind, storms, floods or disturbances on the external electrical system. Power, control and instrument cabling, motors and other electrical equipment required for operation of the engineered safety features are suitably protected against the effects of either a nuclear system accident or of severe external environment phenomena in order to assure a high degree of confidence in the operability of such components in the event that their use is required.

Emergency Power

Criterion: An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single component. (GDC 39 and GDC 24 of 7/11/67)

Independent alternate power systems are provided with adequate capacity and testability to supply the required engineered safety features and protection systems.

The plant is supplied with normal, standby and emergency power sources as follows:

1) The normal sources of auxiliary power during plant operation are both the generator and offsite power.

2) Offsite power is supplied from Buchanan Substation (approximately ¾ mile from the plant) by 138kV and 345kV feeders, and two underground 13.8kV feeders. The Buchanan Substation has two 345kV and two 138kV circuits to Millwood Substation and a 345Kv circuit to Ladentown Substation which interconnects with the PJM system. Millwood Substation has ties to Pleasant Valley Substation which is the interconnection point between Consolidated Edison Company, Niagara Mohawk and Connecticut Light and Power systems. In addition, there are 1-25.4 MW and 1-16.9 MW combustion turbine generators at Buchanan Substation and a 21MW combustion turbine generator located at the Indian Point site. 138Kv feeders are connected to the 6.9 KV buses through the station auxiliary transformer, 13.8 kV feeders and combustion turbines are connected to the 6.9kV buses through autotransformers. 480 volt engineered safety features are connected to the 6.9kV buses through station auxiliary transformers.

3) Three diesel generators are each connected to their respective engineered safety features buses to supply emergency shutdown power in the event of loss of all other AC auxiliary power. There are no automatic ties between the buses associated with each diesel generator.

   Each diesel will be started automatically on a safety injection signal or upon the occurrence of under voltage on its associated 480 volt bus. Any two diesels have adequate capacity to supply the engineered safety features for the hypothetical accident concurrent with loss of outside power. This capacity is adequate to provide a sage and orderly plant shutdown in the event of loss of outside electrical power. The diesel generator units are capable of being started and sequence load begun within 10 seconds after the initial signal.

The three diesel-generators are located adjacent to the control building and are connected to three (3) of the four (4) separate 480 volt auxiliary system buses. The fourth 480 volt bus is automatically connected to the third bus during diesel generator operation, and the two buses are operated as a unit from a single diesel generator for this mode of operation only.

4) Emergency power supply for vital instruments, control, and emergency lighting is from the four 125 volt DC station batteries.

5) A 2500 KW diesel generator capable of providing on-site power for safe shutdown loads has been installed in compliance with 10 CFR 50 Appendix "R"; also support compliance with SBO requirements.

8.2 ELECTRICAL SYSTEM DESIGN

8.2.1 Network Interconnection

The offsite transmission system provides two basic functions for the station; namely, it provides auxiliary power as required for startup and normal shutdown and transmits the output of the station.

Electrical energy generated at 22 kV is raised to 345 kV by the two main generator transformers and delivered to the Buchanan 345 kV Switching Station via 345 kV, 3000 Amp, 25,000 MVA synchronizing circuit breakers. The Buchanan Substation has two 345 kV and two 138 kV circuits to Millwood Substation and a 345 kV circuit to Ladentown Substation which interconnects with the PMJ system. Millwood Substation has ties to Pleasant Valley Substation which is the interconnection point between Consolidated Edison Company and Niagara Mohawk and Connecticut Light and Power System. The Buchanan 138 kV Substation has connections to Lovett Station.

Offsite (standby) power is supplied from Buchanan Substation (approximately ¾ mile from the plant) by 138 kV and 345 kV feeders, and two underground 13.8 kV feeders. In addition, there is 1-25.4 MW and 1-16.9 MW combustion turbine generators at Buchanan substation connected to the 13.8 kV feeders and a 21 MW combustion turbine generator located at the Indian Point Site. The 13.8 kV feeders are connected to the 6.9 kV buses through autotransformers. The 480 volt engineered safety feature buses are connected to the 6.9 kV buses through station auxiliary transformers.

Single-Line Diagram

A single-line diagram, showing the connections of the main generator to the power system grid and to standby power source is shown on Plant Drawing 9321-F-33853 [Formerly Figure 8.2-1].

Reliability Insurance

There are four independent sources of emergency power available to Indian Point 3. They are the 138 kV and 345 kV ties from Buchanan and the two 13.8 kV feeders from Buchanan. In addition, there are three combustion turbine generators, one located on the Indian Point site and the others connected to 13.8 kV feeders at Buchanan, providing a completely independent supply from the rest of the offsite transmission system. The 138 kV supply from the Buchanan bus with its connections to the Consolidated Edison Company system and Orange & Rockland County provide a dependable source of station auxiliary power.

An analysis of the 1971 system demonstrated that the interconnected power system remained stable for the loss of the largest unit, Ravenswood No. 3 (1000 Mwe). Since the transmission system is as strong after the installation of Indian Point 3, and since Indian Point 3 is not as large capacity wise, this analysis can be applied to confirm the stability of the interconnected system for the sudden loss of the largest unit. In addition, a 2500 kw self-contained diesel generator is available to provide on-site power for safe shutdown loads having alternate feed capability.

8.2.2 Station Distribution System

The Auxiliary Electrical System was designed to provide a simple arrangement of buses requiring the minimum of switching to restore power to a bus in the event that the normal supply to that bus is lost.

The relays that are used for bus clearing and sequencing of safeguards components on the four 480 volt buses have been physically located in the 480 volt switchgear and the circuitry has been developed on an individual, independent bus scheme. That is, each bus has its own set of bus clearing and load sequencing relays physically located within its own line-up, independent of the other bus sections. Diesel generator No. 31 is connected to bus No. 2A and bus No. 2A is then connected to bus No. 3A in the event of a diesel requirement. Buses No. 2A and 3A together form one of the three 480 volt safeguards power trains with buses No. 5A and 6A used for the remaining two power trains.

In addition, Indian Point 3 has a five-battery DC System. Each of the three 480 volt safeguards power trains and associated circuitry receives its DC control power from its own individual battery (Nos. 31, 32 and 33). Battery No. 36 feeds power panel No. 36. Battery No. 34 feeds instrument bus No. 34.

Batteries 31, 32, 33, and 34 are safety batteries which supply DC power to safe shutdown systems. Battery 36 is a non-safety battery which supplies DC power to non-essential loads.

Single Line Diagrams

The basic components of the station's electrical system are shown on the electrical one line diagrams, Plant Drawings 617F645, 617F643, 617F644, 9321-F-30063, -30083, 9321-H-36933, and 9321-F-39893 [Formerly Figures 8.2-2 through 8.2-6, 8.2-8 and 8.2-9], which include the 6900 volt, the 480 volt, the 120 volt AC instrument, and the 125 volt DC bus systems.

Unit Auxiliary, Station Auxiliary and Station Service Transformers

Unit Auxiliary Transformer

The unit auxiliary transformer is a three phase, two winding, forced oil/air type. During unit operation, it transforms 22 kV power from the main generator bus to 6.9 kV and, through appropriate switching, supplies four of the six 6900 volt auxiliary buses. These four buses supply virtually all of the unit 6900 volt auxiliaries and approximately 50% of the 480 volt auxiliaries.

Station Auxiliary Transformer

The station auxiliary transformer is a three phase, two winding forced oil/air type. It transforms 138 kV power from the offsite network to 6.9 kV and, through appropriate switching, supplies the remaining two of the six 6900 volt auxiliary buses. During unit operation it supplies the 6900 and 480 volt auxiliary loads that are not supplied by the Unit Auxiliary Transformer.

When the Unit Auxiliary Transformer is not available, such as during unit trip, unit downtime, or startup, the four buses normally supplied by this transformer are reconnected to the two remaining buses, and the Station Auxiliary Transformer supplies all auxiliary loads.

Station Service Transformers

The seven station service transformers are three phase, two winding, air insulated, dry type. Insulation material is fire resistant and non-explosive. Solid insulation in the transformers consists of inorganic materials such as porcelain, mica, glass or asbestos, in combination with a sufficient quantity of high temperature binder to impart the necessary mechanical strength to the insulation structure. This insulation is defined by ASA standards as Group III material. The Station Service Transformers transform 6.9 kV power form the 6900 volt buses to 480 volts to supply low voltage auxiliary loads.

The above transformers were designed and constructed in accordance with the applicable standards of ASA, IEE and NEMA. During normal operation and auto engineered safeguards loading, these transformers will not be loaded beyond their rating. However, during peak accident loading scenarios, these transformers are allowed to be loaded up to 3600 amps, for up to 4 hours. This short time overload capability is necessary to support the 480V buses 2A, 3A, 5A, and 6A loading requirements during the manual recovery phase of a design basis accident. Manufacturer shop tests of the transformers were conducted in accordance with the latest revision of American Standard Test Code C 57.12.90. This series of tests consisted of the following:

1) Resistance measurements of all windings,
2) Ratio tests,
3) Polarity and phase relation tests,
4) No-load losses,
5) Exciting current,
6) Impedance and load loss,
7) Temperature test,
8) Applied potential tests, and
9) Induced potential tests.

6900 Volt System

The 6900 volt system is divided into seven buses. These buses supply 6900 volt auxiliaries directly and 480 volt auxiliaries via the station service transformers. Two buses, numbers 5 and 6, are connected to the 138 kV system via bus main breakers and the Station Auxiliary Transformer. An alternate connection is available to the 13.8 kV gas turbine and/or the 13.8 kV off-site power network via a step-down auto transformer. Buses No. 1, 2, 3, and 4 are connected to the generator leads via bus main breakers and the Unit Auxiliary Transformer. Buses No. 1 and 2 can be tied to Bus No. 5 and Buses No. 3 and 4 can be tied to Bus No. 6 via bus tie breakers to provide auxiliary power during unit down time. These bus tie connections are automatically initiated, in the event of unit trip, to assist continuity of service. BUS 3NBY01 is connected to the 13.8 kV off-site power network via a step-down auto transformer.

480 Volt System

The 480 volt system consists of seven buses, each supplied from a 6900 volt bus via a station service transformer. Four of these Buses, No. 2A, 3A, 5A and 6A, supplied from Buses No. 2, 3, 5, and 6 respectively, comprise the safety related 480 volt system. The required safeguards equipment circuits are dispersed among these buses. These buses are provided with diesel generator back-up in the event of voltage failure, and are protected against a sustained undervoltage condition, which could cause mis-operation of, or damage to, safeguards equipment. 480V Buses 2A, 3A, 5A and 6A are each rated 3200 amps continuous. However, during peak accident loading scenarios, these buses can be loaded up to 3600 amps for up to 4 hours, based on a maximum ambient switchgear room temperature of 40°C. For Buses 2A and 3A, this short time limit applies to the combined loading, when these buses are tied together and powered from a single station service transformer. (Buses 2A and 3A are considered a single safeguards bus.)

480 Buses 2A, 3A, 5A and 6A load breakers are rated to interrupt up to 50kA short circuit current. Maximum short circuit current at the 480V load breakers during emergency diesel generator testing parallel to the system, was initially and conservatively calculated to be slightly greater than 50kA. However, taking into account cable and raceway construction, and establishment of "safe zone" areas during diesel testing (CAT I areas), the maximum fault current was analyzed to be less than the 50kA rating which would allow the breaker to safely interrupt a fault if it occurs.

The three remaining 480 volt buses, Buses No. 312, 313, and 3NGY01 are supplied from 6900 volt Buses No. 1, 3 and 3NBY01 respectively, and supply auxiliary power to additional plant facilities installed subsequent to the initial installation. A tie breaker between Buses 312 and 313 permit one bus to serve as a backup for the other. Interlocking prevents the cross connecting of the two 6.9 kV sources to Buses 312 and 313 through the 480 volt system. The interlock can be defeated temporarily for performing a live transfer of 480 volt buses 312 and 313 when both 6.9 kV supply buses are fed from the same 6.9 kV power source.

The 480 volt feeders for the Fire Protection System are from the 480 Volt Buses No. 312 and 313 to the 480 volt Motor Control Center G and H, respectively. Buses No. 312 and 313 are located in the Turbine Hall and Motor Control Centers G and H are located in the Fire Pump House. The motor driven fire pump normal feed is Bus No. 312 and the emergency feed is 480 volt Bus No. 5A. These feeders run through the manual transfer switch which is used to manually transfer the feeders to the motor driven fire pump from the normal feed to the emergency feed and from the emergency feed to normal feed. The electrical feeds to the remaining equipment installed as part of the additional facilities program are supplied through individual breakers.

The normal source for Buses No. 5A and 6A is the 138 kV system, via the station auxiliary transformer and 6900 volt Buses No. 5 and 6. The normal source for Buses No. 2A and 3A is the main generator, via the unit auxiliary transformer and 6900 volt Buses No. 2 and 3. When the unit is not operating, Buses No. 2A and 3A are supplied from the 138 kV system, via switching at the 6900 volt level. The normal source for Bus No. 3NGY01 is the 13.8 kV system via an autotransformer and 6900 volt Bus 3NBY01.

The relays that are used for bus clearing and sequencing of safeguards components on the four safety related 480 volt buses have been physically located in the 480 volt switchgear, and the circuitry has been developed on an individual, independent bus scheme. That is, each bus has its own set of bus clearing and load sequencing relays physically located within its own lineup, independent of the other bus sections.

Two independent sets of under-voltage protective relays are installed on each bus: one set to initiate load stripping, diesel generator start, bus transfer, and sequencing of safeguards loads upon bus voltage failure; the other set to initiate bus disconnection from the offsite power source upon the occurrence of a sustained period of voltage low enough to cause mis-operation of, or damage to, safeguards equipment.

Coordination between 480V Buses 2A, 3A, 5A and 6A supply breakers and their downstream load breakers ensures that an entire bus will not be lost due to a fault on any feeder circuit.

One emergency diesel-generator set is connected to bus No. 5A, one to 6A and the third to the combination of Bus No. 2A and Bus 3A. Each diesel generator is automatically started upon under-voltage on its associated 480 volt bus.

Interlocks are provided so that a fault on any bus locks out all possible sources of power to that bus. Interlocks are also provided to prevent circuit breakers connecting emergency diesel generator No. 31, 32 and 33 to Buses No. 2A, 6A and 5A from automatically closing if there is a voltage on the bus. The power for the safeguards valve motors is supplied from two motor control centers which in turn are supplied from the safety related 480 volt system. Each motor control center can be supplied by an emergency diesel generator.

Each of the four 480 volt switchgear bus sections which supply power to the safeguards equipment receives DC control power from its associated battery source. Batteries No. 31, 32, and 33 supply DC control power to 480 volt bus No. 5A, 6A and 2A/3A, respectively.

<u>125 Volt DC System</u>

The 125 volt DC system is divided into five buses with one battery and battery charge (supplied from the 480 volt system) serving each. The battery chargers supply the normal DC loads as well as maintaining proper charges on the batteries.

One battery charger is available to each battery so that the five batteries are maintained at full charge in anticipation of loss-of-AC power incident. This ensures that adequate DC power is available for starting the emergency generators and other emergency uses.

Battery chargers 31, 32, and 33 are also relied upon to support the continued operation of systems and components required to either mitigate the consequences of a design basis accident or provide post-accident monitoring subsequent to depletion of Batteries No. 31, 32, and 33.

The DC system is redundant from battery source to actuation devices which are powered from the batteries. Five batteries feed five DC power panels, which in turn feed major loads, such as instrument bus inverters, switchgear control circuits and DC motors. Two of the DC power panels sub-feed DC distribution panels, which in turn feed relaying and instrumentation loads. Redundant safeguards relays and devices which use DC as a power source receive their power from one of three DC distribution buses.

Bus ties exist between Power Panels 31 and 32 and between Power Panels 33 and 34. These bus ties are administratively controlled open when the plant is in any condition above cold shutdown, to preserve the 125 VDC system independence. During cold shutdown, only one of these bus ties, either between Power Panel 31 and 32, or between Power Panels 33 and 34 can be closed. The bus tie feature is provided to allow maintenance, and / or removal of one of the four Station batteries. The remaining battery on the two cross connected buses has adequate capacity to supply DC power for the tied Power Panel loads for a minimum of two hours during a loss of AC power design basis event.

Safeguards pump controls which are DC actuated receive power from their associated DC distribution buses.

The physical locations of the DC system equipment is such as to minimize vulnerability of vital circuits to physical damage and prevent concurrent loss of all power as a result of accidents. The DC system is designed such that a single random failure will not result in the loss of redundant DC power and/or Distribution Panels due to a common mode electrical failure.

Major loads with their appropriate operating times on each battery are listed in Table 8.2-2.

<u>120 Volt AC System</u>

The 120 volt AC instrument supply is split into four buses. All four buses are fed by inverters which are in turn supplied from separate 125 volt DC buses. In addition, an alternate power supply is provided for the fourth bus consisting of a constant voltage transformer connected to a 480 volt safeguards motor control center No. 36B. In the event that inverter 34 or the constant voltage transformer is taken out of service, a backup source consisting of a second constant voltage transformer connected to a different 480 volt safeguards MCC is available to feed the associated bus.

Inverters 31, 32, and 33 have manual bypass switches which can bypass the inverter and supply the associated instrument bus from a backup constant voltage transformer connected to a 480 volt MCC. In addition, inverters 31, 32, and 33 have automatic static transfer switches which will transfer to the backup constant voltage transformer supply in the event of loss of inverter voltage, loss of DC voltage, inverter circuit failure, electrical fault or inverter undervoltage.

Inverters 31, 32, and 33, each have a harmonic filter installed to maintain voltage total harmonic distortion (VT_{HD}) within design limits. This reduces instrumentation biases to VT_{HD} sensitive instruments to acceptable limits.

<u>Evaluation of Layout and Load Distribution</u>

The physical locations of the electrical distribution system equipment are such as to minimize vulnerability of vital circuits to physical damage as a result of accidents.

Station and unit auxiliary transformers, and the main transformer are located outdoors and are physically separated from each other.

Lightning arresters are used where applicable for lightning protection. All oil filled transformers are covered by automatic spray systems to extinguish oil fires quickly and prevent the spread of fire. Transformers are spaced to minimize their exposure to fire, water and mechanical damage.

The 6900 volt switchgear and 480 volt load centers are located in areas which minimize their exposure to mechanical, fire and water damage. This equipment is properly coordinated electronically to permit safe operation of the equipment under normal and short circuit conditions.

The 480 volt motor control centers are located in the areas of electrical load concentration. Those associated with the turbine-generator auxiliary system in general are located below the turbine-generator operating floor level. Those associated with the nuclear steam supply system are located in the Primary Auxiliary Building.

Non-segregated, metal-enclosed 6900 volt buses are used for all major bus runs where large blocks of current are to be carried. The routing of this metal-enclosed bus is such as to minimize its exposure to mechanical fire and water damage.

The application and routing of control, instrumentation and power cables are such as to minimize their vulnerability to damage from any source. All cables are designed using conservative margins with respect to their current carrying capacities, insulation properties and mechanical construction. Power cable insulation in the Reactor Building has fire resistant sheathing, selected to minimize the harmful effects of radiation, heat and humidity.

Appropriate instrumentation cables are shielded to minimize induced voltage and magnetic interference. Wire and cables related to engineered safeguard and reactor protective systems are routed and installed to maintain the integrity of their respective redundant channels and protect them from physical damage.

The following design and construction procedures were followed to assure a safe and adequate design:

Redundancy and separation requirements were initiated by the cognizant electrical or mechanical design engineer. These were then reviewed by the designers of the electrical system installation, thus providing a check. The work of the designer, who prepared the applicable circuit schedule sheet (which designates the cable routing and termination), was spot checked by the cognizant electrical engineer.

The construction group installed the cable as directed by the circuit schedule sheet. The installations were verified by WEDCO field engineers and spot checks of circuit installations were made to further ensure that the installation was in accordance with the design. Consolidated Edison spot checked the installation.

Cable loading of trays and consequently heat dissipation of cable throughout the plant has been carefully studied and controlled to ensure no overloading. The criteria for electrical loading has been developed using IPCEA Standard P-46-426, manufacturer recommendations and good engineering practice.

Derating factors for cables in trays without maintained spacing were taken from Table VIII of the IPCEA publication. Derating factors for the maximum ambient temperature existing in any area of the plant were also taken from the IPCEA publication. These factors were applied against capacities selected from appropriate tables in other portions of the standard.

For physical loading of trays, the following criteria was followed: 6.9 kV power, one horizontal row of cables with spacing was allowed in a tray; 480 volt power, two horizontal rows of cables were allowed in a tray (if derating requirements did not dictate less); for control and instrumentation, the tray was filled to a point just below the top (the total cable area for this configuration is 60% of tray cross-sectional area). A computer program was used to monitor cable routing and tray loading.

Cables which do not require channeling may be run in any tray or conduit; however, once it entered a tray or raceway containing a channeled cable, it does not leave this channel and enter another tray containing a cable from a different channel.

To assure that only fire retardant cables were used throughout the plant, a careful study of cable insulation systems was undertaken early in the design. Insulation systems that have superior flame retardant capability were selected and manufacturers were invited to submit cable sample for testing. An extensive flame testing program took place which included ASTM vertical flame testing and Consolidated Edison Company vertical flame and bonfire tests as described below. These flame tests were used as one of the means of qualifying cables and specifications were written on the basis of the results from the tests.

The following tests were made to determine the flame resistant qualities of the covering and insulation of various types of cables for Indian Point 3:

1) Standard Vertical Flame Test – made in accordance with ASTM-D-470-59T, "Test for Rubber and Thermalplastic Insulated Wire and Cable."*

2) Five-Minute Vertical Flame Test – made with cable held in vertical position and 1750 F flame applied for five minutes.

3) Bonfire Test – Consisting of exposing, for five minutes, bundles of three or six cables to flame produced by igniting transformer oil in 12-inch pail. The cable was supported horizontally over the center of the pail, the lowest cable three inches above the top of the pail. The time to ignite the cable and the time the cable continued to flame after the fire was extinguished were noted.

On the basis of these tests, the cables were selected for the Reactor Containment Building for Indian Point 3.

*NOTE: This Standard has since been revised and the provisions of the currently approved version (ASTM-D-470-71) are less restrictive than the requirements of Tests 2) and 3). Therefore, cable procured by Consolidated Edison and the Authority after 1971 is qualified in accordance with the more stringent requirements of the Five-Minute Vertical Flame Test and the Bonfire Test.

Cables are protected in hostile environments by a number of devices. Running the cable in rigid, galvanized conduit is the most frequently of used method protection. For underground runs, PVC heavy wall conduit encased in a concrete envelope provides maximum protection. When cable is run in a tray, peaked covers are used in areas where physical damage to cables may result from falling objects or liquids. In addition, covers are provided on horizontal cable trays which are exposed to the sun.

Fire protection measures to prevent propagation of flame are discussed in Section 9.6-2. Fire detection is provided for areas where there are large groupings of cables in stacked cable trays. The plant has a protective signaling system that transmits fire alarm and supervisory signals to the Control Room where audible and visual alarms are provided. The system includes signals for actuation of fire detectors, and automatic sprinkler, water spray, foam and CO2 systems. Electrical supervisory signals are received from tamper switches on fire water system control valves.

Cables and wireways are marked by means of metal tags attached at each end. These tags are embossed to conform with the identification given in the Conduit and Cable Schedule. At each multiple conductor cable termination, a plastic covering is attached which as been premarked to indicate the terminal designation of each conductor. In addition, cable trays are marked at frequent intervals to indicate the channel number and voltage level of the tray. Color coding is discussed in Section 7.2.

In areas where missile protection could not be provided (such as near the Reactor Coolant System) redundant instrument impulse lines and cables were run by separate routes. These lines were kept as far apart as physically possible, or were protected by heavy (1/4") metal plates interposed where inherent missile protection could not be provided by spacing.

8.2.3 Emergency Power

Sources Description

Standby power required during plant startup, shutdown and after turbine trip is supplied from one 345kV feeder and one 138 kV feeder from the Buchanan Substation (approximately 3/4 mile from the plant) which as connections to the Millwood Substation and the Lovett Station of the Orange and Rockland system. These connections are made through the station auxiliary transformer.

In addition, there are two underground 13.8 kV feeders from the Buchanan Substation. There is also 1-25.4 MW and 1-16.9 MW combustion turbine generator at Buchanan connected to these 13.8 kV underground feeders, and a 21 MW combustion turbine generator located on the Indian Point site. The 13.8 kV feeders are connected to the 6.9 kV buses via autotransformers. If these sources should fail, the on-site sources of emergency power are three emergency diesel generator sets, each consisting of an Alco model 16-251-E engine coupled to a Westinghouse 2188 KVA, 0.8 power factor, 900 rpm, 3 phase, 60 cycle, 480 volt generator. Each unit has a 2000 hour and a 2 hour rating of 1950 kW and a 1750 kW continuous rating. There is also a vendor stated maximum ½ hour rating of 2000 kW. This is not an operational limit but an area of additional margin for handling power surges and spikes which may occur during testing. In addition, an alternate on-site source of power for safe shutdown loads is available from the

Appendix "R" Diesel Generator which consists of an ALCO model 251 engine coupled to a KATO model 8P103600 3125 KVA, 0.8 power factor, 900 rpm, 3 phase, 60 cycle, 6900 volt Generator.

On July 21, 1988, 10 CFR 50 was amended to include a new Section 50.63 entitled, "Loss of All Alternating Current Power," (Station Blackout). The Station Blackout (SBO) Rule requires that each light-water-cooled nuclear power plant be able to withstand and recover from an SBO of specified duration.

The Authority submitted to the NRC its response to the SBO rule. The NRC responded by issuing a Safety Evaluation dated December 23, 1991 and a Supplemental Safety Evaluation dated June 8, 1992. Based on these safety evaluations, and IPN-94-127, dated October 13, 1994, the following SBO-related items are resolved:

1) Habitability of the areas from which the AFW flow control valves and steam generator PORVs are operated during the first hour after the onset of an SBO event was evaluated and determined acceptable.

2) In order to address the effects of loss of ventilation of the control room, control room cabinet doors will be opened within 30 minutes of the onset of an SBO event.

3) The containment Isolation Valve design and operation meets the intent of the guidance described in Regulatory Guide 1.155. Specific containment isolation valves which cannot be excluded based on the 5 criteria given in Regulatory Guide 1.155 are documented to justify their exclusion and ensure that containment integrity will be maintained during an SBO event.

4) All equipment required for response to an SBO shall be classified (at least) Category M, and included in the QA Program.

5) The EDG reliability program follows the guidance and meets the intent of Regulatory Guide 1.155. This program includes monitoring of EDG reliability, surveillance and testing of the EDGs, maintenance program, an information and data collection system and management oversight.

6) The coping duration categorization of IP3 has been revised from four to eight hours.

Any two emergency diesel generator units, as a backup to the normal standby AC power supply are capable of sequentially starting and supplying the power requirement of one minimum required set of safeguards equipment. The three units are located in a seismic Class I structure located near the Control Building.

Each emergency diesel is automatically started by two redundant air motors, each unit having a complete 53 cu ft air storage tank and compressor system powered from a 480 volt motor. The piping and the electrical services are arranged so that manual transfer between units is possible. Each air receiver has sufficient storage for 4 starts. The diesel will consume, however, only enough air for one automatic start during any particular power failure. This is due to the engine control system which is designed to shutdown and lock out any engine which did not start during the initial try.

The emergency units are capable of being started and sequence load begun within 10 seconds after the initial signal. The starting system is completely redundant for each diesel generator. The units have the capability of being fully loaded within 30 seconds after the initial starting signal.

To ensure rapid start the units are equipped with water jacket and lube oil heating and pre-lube pump for circulation of lube oil when the unit is not running. The units are located in heated rooms.

An audible and visual alarm system is located in the main control room and will alarm off-normal conditions of jacket water temperature, lube oil temperature, fuel oil level, and starting air pressure.

The abnormal conditions that can shut down the diesel generator during an accident are:

1) overcranking
2) low oil pressure
3) overspeed

An auto shutdown alarm system provided three alarms in the Control Room; one for each emergency Diesel Generator. The alarm annunciates when a shutdown, lock out, control switch off auto or loss of DC power condition occurs. These alarms, located in the Control Room, will identify the diesel generator that has been tripped or is prevented from starting, because of a lock-out shutdown condition or loss of DC power.

Each emergency diesel generator was designed to start and come up to speed within ten seconds after initiation of the starting signal. Failure of the engine to start within the timing period of the overcrank time indicates a malfunction. The overcrank relays have a setpoint (approximately 15 seconds) that allows the diesel engine enough time to start and at the same time, does not allow the air tank to deplete itself. Shutdown conserves the starting air supply so that the engine can be subsequently started after the malfunction is corrected. Low oil pressure indicated by two out of three oil pressure switches shuts down the diesel generator, since the engine cannot run without proper lubrication. Shutdown permits corrective action to be taken before the engine is damaged, and the diesel generator can then be returned to normal operation.

An overspeed condition causes improper generator output and therefore the diesel generator should be shut down for corrective action to be taken to restore the generator output to normal.

For operator indication that one or more emergency diesel generators have been disabled for test or maintenance purposes there is an annunciator window labeled "SAFEGUARDS EQUIPMENT LOCKED OPEN." This alarm is initiated on signals from various safeguards components including the diesels. From any one of the three diesels the following signals would actuate the alarm:

1) Main Control Board Generator Breaker Control Switch in pull-out position
2) Local Generator Breaker Control Switch in pull-out position
3) Local Diesel Control Switch in off or manual position.

Fuel oil for the emergency diesel generators is stored in three 7,700 gallon underground storage tanks located on the south side of the Diesel-Generator Building. There is one common truck hose connection and a 4-inch fill line for all three tanks, complete with a four-inch shutoff valve at each tank. The overflow from any tank will cascade into an adjacent tank. Each tank is equipped with a single vertical fuel oil transfer pump that discharges to either a normal or emergency header. Each header independently supplies the day tank at each diesel. An alarm will sound in the control room if the level in any underground storage tank approaches the level equivalent of the minimum total required inventory identified below less the indicating uncertainty. Administrative action will be taken to refill the tank. In addition, there is a low-level pump cutout switch located on each tank to prevent damage to the fuel oil transfer pump. Each tank is also equipped with a sounding connection and a level indicator. Decrease in level in a day tank to approximately 115 gallons (65% full) will cause the transfer pump in the corresponding underground storage tank to start. Once started, the pump will continue to run until the day tank is filled. When the tank is filled, a level switch will initiate closing of the day tank inlet valve and discontinue operation of the fuel oil transfer pump.

The minimum required usable inventory for each of the three storage tanks is specified in the Technical Specifications. The safety design criteria are based on the need to provide adequate fuel to support forty-eight (48) hour operation of minimum safeguards equipment following a design basis accident. The minimum required inventory (gallons) for fulfillment of the safety design criterion is based on the following:

	31 Tank	32 Tank	33 Tanks
Calculated consumption (TS Required Usable)	5,365	5,365	5,365
Margin reduction due to re-coating	20	20	20
Level indication uncertainty	50	50	50
Unusable (pump cutoff worst case drift)	915	915	956
Total minimum required Inventory	**6,350**	**6,350**	**6,396**

No credit is taken in the above tabulation for the inventory of oil in the EDG day tanks. Each emergency diesel is equipped with a 175-gallon day tank. The transfer pump start and fill valve open function is initiated when the level in the tank approaches (decreases toward) 65% (of nominal full) level, approximately 115 gallons. The 32 fuel oil storage tank was re-coated during RO10. A conservative estimate of the volume reduction of the tank was made and the required inventory for fulfillment of the safety design criterion adjusted accordingly.

Fuel flows by gravity to the engine, insuring a static head of fuel oil on the injection manifolds. Excess fuel oil is collected in a drip tank located in the base of the diesel engine. A manually operated drain pump is provided so that the drip tank can be emptied. The diesel fuel oil storage and transfer system diagram is shown in Plant Drawing 9321-F-20303 [Formerly Figure 8.2-7].

A usable amount of 37556 gallons of fuel oil is required to operate two emergency diesels at minimum safeguards load continuously for 168 hours. An assumed 10730 gallons is available assuming the unlikely event that one underground storage tank is unavailable. Based on No. 2 diesel fuel oil with a minimum density of 6.91 lbs/gallon and an average consumption rate of 0.363 lbs/hp-hr, this capacity is sufficient to operate two diesels at minimum safeguards for at least 48 hours. An additional minimum usable storage of 26,826 gallons is necessary to assure continuous operation of two diesels at minimum safeguards load for a total of 168 hours. This reserve is in addition to the storage requirements for other plants at the site. The usable amount of 37,556 gallons of fuel oil is necessary to operate two diesels for seven days to maintain the unit in a cooldown condition concurrent with a loss of offsite power.

The Technical Specifications require 26,826 gallons of fuel as minimum usable storage available for Indian Point 3 usage in other normal supply tanks on site or at the Buchanan Substation. Also, additional supplies of diesel fuel oil are available locally.

There are two 30,000 gallon seismic Class III tanks located in the Indian Point 1 Superheater Building and a 200,000 gallon seismic Class III tank in the Buchanan Substation located immediately across Broadway. These tanks contain fuel oil for operation of combustion turbines that is compatible for use with the diesels. Each tank has a level indicator and a capacity check is made weekly. When the combustion turbines are being operated, the dispatcher will be notified to start oil deliveries and to keep the tanks filled. The gas turbines consume approximately 2000 gallons per turbine per hour. A truck with hose connections compatible with the underground storage tanks will be provided. If the diesels require the reserves in these tanks, the contents of these tanks would be transported by truck to the underground diesel storage tanks. Additional supplies of diesel oil are available locally. Under normal conditions, 25,000 gallons can be delivered on a one or two-day notice. Additional supplies are also maintained in the region (about 40 miles from the plant) and are available for use during emergencies, subject to extreme cold weather conditions (increased domestic heating usage) and available transportation.

All components of the emergency diesel fuel oil supply system are seismic Class I and as such were designed in accordance with the criteria of Section 16.1. In addition, all components of the diesel fuel oil supply system are tornado protected and as such are able to withstand the design tornado and the tornado driven missiles delineated in Section 16.2. These components are also protected against the turbine missiles described in Appendix 14A of Chapter 14. The power supply and control system for the diesel fuel oil transfer system were designed in accordance with IEEE-279, meeting fully the single failure criteria specified therein.

Fuel oil for the emergency diesel generators is stored in three buried storage tanks. Each tank is equipped with a single vertical fuel oil transfer pump that discharges oil into either of two headers according to the manual valving arrangement selected. Both of these headers connect to a 175-gallon day tank mounted on each of the three diesel engines.

Decrease in level in any one of the three day tanks to the 65 percent level automatically starts its associated fuel oil transfer pump (local manual controls are also available). The fuel oil transfer pumps are powered from motor control centers 36C, 36D, and 36E. Since each pump is capable of supplying fuel oil to all three diesels, this arrangement assures the availability of fuel oil to each diesel.

Each day tank is provided with AC normal level and low level indicating lights. In addition, each day tank has a DC low-low alarm on its respective diesel generator control panel which also annunciates a common Diesel Generator Trouble Alarm on the supervisory panels in the Control Room.

Diesel-Generator Separation

The emergency diesel generators are located in a tornado-proof reinforced concrete building immediately adjacent to the Control Building. The diesel generators are arranged on 13'-0" centers, parallel to each other with approximately 10'-0" between engine components. The structure is provided with internal walls to separate the three diesel generators and their associated cabling and control panels from each other for fire protection. Fire protection and detection systems for the diesel generators are discussed in Section 9.6.2.

Each control panel contains relays and metering equipment for its diesel generator. In the event of an electrical fire the event is annunciated in the main control room. With the compartmentalized diesel generator separation design, and the fire protection systems provided, spread of fire from one unit and its associated equipment to the other units is minimized.

Each emergency diesel generator has its own small fuel storage (day) tank that feeds the fuel oil pump on the engine. All day tanks are automatically filled during engine operation from three separate underground storage tanks outside the diesel generator building. Each storage tank has its own supply pump mounted in a manhole opening in the top of the tank above oil level. It is therefore unlikely that a fire associated with any one of the small fuel oil storage (day) tanks would prevent oil from being supplied to the remaining two diesels.

Loading Description

Each unit is to be started on the occurrence of either of the following incidents:

1) Initiation of safety injection operation;
2) Undervoltage on its own bus.

On occurrence of undervoltage without safety injection the engines are started and connected to their respective bus.

If there is coincident or subsequent requirement for engineered safeguards, automatic sequencing is initiated as follows:

1) Emergency diesel No. 31 is connected to and capable of supplying bus No. 3A in addition to bus No. 2A (via a bus tie between buses No. 2A and 3A) in the event of a safeguards system requirement.

2) All 480 volt breakers, except those feeding the motor control centers numbers 36A, 36B, 36C, 36D, 311 and 36E are tripped and all automatically operated non-safeguards' feeders are locked out. All engineered safeguards motors are operated from the 480 volt buses.

3) Connect the diesel generators to their respective buses.

4) Magnitude of loads for each emergency diesel generator is given in Table 8.2-1A.

If a diesel fails to start or a bus fault occurs, the loads as indicated on the associated bus will not start. The remaining loads on the unaffected buses meet the minimum safeguards requirements.

The recirculation phase is manually initiated by control switches on the supervisory panel in the main control room. As the sequence switches are operated, the bus loads are modified to give those shown in Reference 1 for the respective Design Basis Accidents.

Emergency Diesel Generator Loading

The following "minimum safeguards" equipment is required and assumed to be operating for a design basis event at Indian Point Unit 3:

2 of 3 Safety Injection (SI) Pumps
1 of 2 Residual Heat Removal (RHR) Pumps
1 of 2 Motor Driven Auxiliary Feedwater (AFW) Pumps
1 of 2 Recirculation Pumps
3 of 5 Containment Recirculation (CR) Fans
1 of 2 Containment Spray (CS) Pumps
1 of 3 Nonessential Service Water (NE SW) Pumps
2 of 3 Essential Service Water (ESW) Pumps
1 of 3 Component Cooling Water (CCW) Pumps

Due to interactions between systems, minimum requirements for safety vary with the loss of any one diesel generator. See Chapter 14.3 for details.

This configuration is based on the assumptions of a single active failure of an emergency diesel generator and that 1 CCW and 1 NE SW pump may be out of service at the time of the accident. In addition to the required equipment listed above, the operator may manually load other equipment during the recovery process as instructed by the Emergency Operating Procedures (EOPs) or System Operating Procedures (SOPs).

The maximum steady state power requirements for equipment that is either automatically or manually loaded in the emergency diesel generators following a loss of offsite power and SI actuation have been conservatively calculated in Reference 1. The diesel generator loading in each of the following design base accidents; large break loss of coolant, small break loss of coolant, main steam line break, and steam generator tube rupture are evaluated in Reference 1 for the actual sequence of loading that the control room operators would initiate as they respond to a DBA. In the initial stage for the worst case accident, the peak load is less than 1950 kW. As the plant approaches steady state (accident stabilized) conditions the EDG loading is less than the unit 1750 kW continuous rating. The maximum steady state power requirements for equipment loading in the emergency diesel generators following a reactor trip without engineered safeguard actuation (SI) with loss of offsite power have been conservatively calculated in Reference 2. Similar to the SI accident scenarios, at the initial stage of the accident the peak load is less than 1950 kW. At steady state, the diesel load is less than 1750 kW. Equipment loading range on the EDG's for both the SI and Non-SI accidents is summarized in Table 8.2-1A.

The worst case transient loading histories were computed assuming the possibilities of a diesel failure combined with equipment out of service.

Design basis events which do not actuate the safety injection system will result in lower emergency diesel loading than those that do.

Testing

To verify that the emergency power system will respond within the required time limit and when required, the following tests shall be performed periodically.

a) Manually initiated demonstration of the ability of the diesel generators to start and deliver power up to nameplate rating when operating in parallel with other power sources. Normal plant operation will not be affected. The duration of the test is at least one hour to at least 50% of continuous rating.

b) Demonstration of the readiness of the system and the control systems of vital equipment to automatically start or restore to operation particular vital equipment by simulating a loss of all normal AC station service power supplies. This test is conducted as required by the Technical Specifications.

The starting of the diesel generator sets can be tested from the Diesel Generator Building. The ability of the units to start within the prescribed time and to carry intended loads are checked periodically. (See Section 8.5).

In addition, each diesel generator shall be inspected and maintained following the manufacturer's recommendations for this class of standby service.

Batteries and Battery Chargers

Lead acid station Batteries No. 31, 32, 33, and 34 have been sized to carry their expected shutdown loads following a plant trip and a loss of all AC power for a period of 2 hours without battery terminal voltage falling below its minimum required voltage. Lead acid station Battery No. 36 has been sized to carry its load for a period of 3 hours without falling below 105 volts. Major loads with their approximate operating times on each battery are listed in Table 8.2-2.

The five battery chargers have been sized to recharge the above partially discharged batteries within 15 hours while carrying its normal load. Battery chargers 31, 32, and 33 are also relied upon to support the continued operation of systems and components required to either mitigate the consequences of a design basis accident or provide post-accident monitoring subsequent to depletion of Batteries No. 31, 32, and 33.

Battery Charger 35 is an installed spare charger which can be utilized as a replacement for any one of Battery Chargers 31, 32, 33, or 34. Battery Charger 35 can be supplied from either MCC -36C, -36D, or –36E via a plug / receptacle arrangement. This arrangement will allow BC 35 to be supplied from the same source as the Battery Charger it is being used to replace, or in the case when it is replacing BC 34, a more reliable source. This will allow BC35 to be supplied from the proper train for its intended use.

The battery system consists of four batteries (No. 31, 32, 33, and 34), each of which generates hydrogen during a floating charge or an equalizing charge. For batteries No. 31, 32, and 34 with the worst case assumptions of the exhaust fan out of service and no natural ventilation, or for battery No. 33 with no exhaust systems or any natural ventilation in effect, with temperatures as high as 104°F, the time to accumulate a hydrogen buildup to four percent under various charging conditions is:

Battery No. 31	floating charge equalizing charge	>23 hours >3 hours
Battery No. 32	floating charge equalizing charge	>30 hours >3 hours
Battery No. 33	floating charge equalizing charge	>77 hours >7.7 hours
Battery No. 34	floating charge	>11.5 hours

	equalizing charge	>3.8 hours
Battery No. 36	floating charge equalizing charge	>17 hours >7.8 hours

The ventilation system for Battery Rooms No. 31, 32, 34 and 36 operate continuously, to preclude any hydrogen build-up. (Station Battery No. 33 is located in Diesel Generator Room No. 31 and does not require forced ventilation.) Loss of the battery room ventilation is annunciated in the Control Room; loss of diesel operating room ventilation is detected by supervisory personnel observations and/or normal operating maintenance procedures.

Normally the batteries are on continual floating charge. They are placed on a 24 hour equalizing charge every quarter or after an emergency battery discharge. (Manual actuation is required at the battery chargers to place the batteries on equalizing charge.)

There is one (1) annunciator window labeled "Battery Charger Trouble." This alarm is set off on the following signals from battery chargers as indicated:

SIGNAL	CHARGERS
1) Low DC Voltage	31, 32, 33, 34, 35, & 36
2) Ground Detection	31, 32, 33, 34, 35, & 36
3) AC Power Failure	31, 32, 33, 34, 35
4) High-Low AC Voltage	36
5) Over Temp	31, 32, 35 & 36
6) High DC Voltage	36
7) High DC Voltage Shutdown	31, 32, & 35
8) Battery Discharge	31, 32, 35 & 36
9) Charger Failure	36

Each individual signal can be isolated on each individual charger listed. Indication is provided at each charger when at any signal is isolated on that charger.

<u>Reliability Assurance</u>

The electrical system equipment is arranged so that no single contingency can inactivate enough safeguards equipment to jeopardize the plant safety. The 480-volt safeguards equipment is arranged on 4 buses. The 6900-volt equipment is supplied from 7 buses.

The plant auxiliary equipment is arranged electrically so that multiple items receive their power from the two different sources. The charging pumps are supplied from the 480 volt buses No. 3A, 5A and 6A. The nine service water pumps and the five containment fans are divided among five of the 480-volt buses. Valves are supplied from motor control centers, No. 36A and 36B, which are supplied from buses No. 5A and 6A.

The outside source of power is adequate to run all normal operating equipment. The 138 kV – 6.9 kV station transformer can supply all the auxiliary loads.

The bus arrangements specified for operation ensure that power is available to an adequate number of safeguards auxiliaries.

Minimum engineered safeguards can be carried by any two diesel generators. These safeguards can adequately cool the core and maintain containment pressure within the design value for the Design Basis Accident.

One battery charger is available to each battery so that the four batteries will always be at full charge in anticipation of loss-of-AC power incident. This ensures that adequate DC power will be available for starting emergency generators and other emergency uses.

8.2.4 Engineered Safeguards Components

The initiation, control and sequencing design of engineered safeguards components, Auxiliary Feedwater System, and Component Cooling Water System is as shown on the schematics listed on Table 8.2-3.

References

1) Calculation IP3-CALC-ED-00207, 480V Bus 2A, 3A, 5A & 6A and EDGs 31, 32 & 33 Accident Loading.

2) Calculation IP3-CALC-ED-00358, Electrical Load Study 480 Volt Safeguard Bus Loading Reactor Trip / No SI, and Loss of Feedwater Transient / No SI, with Offsite Power Available.

TABLE 8.2-1A

LOAD SCHEDULE FOR DIESEL GENERATORS

Loads on Bus 5A (Emergency Diesel Generator 33)

Automatic Loads		Manual/Optional Loads	
Equipment	Load Range (KW)	Equipment	Load Range (KW)
SI Pump 31	327-330	CR Pump 31	294-296 (3)
CS Pump 31	324-332	NE SW Pump 31	276-281
CR Fan 31	157-160	CCW Pump 31	219-224
CR Fan 33	157-160		
ESW Pump 34	276-280	MCC 39	116-131
MCC 36A	93-145 (1)	Chg Pump 31	149-150
		Przr Htrs 33	208-485
		MCC 38 (CRDM Fans)	77-83
MCC 311	75-600 (4)	MCC 311	75-600 (5)

Loads on Bus 2A/3A (Emergency Diesel Generator 31)

Automatic Loads		Manual/Optional Loads	
Equipment	Load Range (KW)	Equipment	Load Range (KW)
SI Pump 32	327-330	NE SW Pump 32	276-281
RHR Pump 31	315-317 (2)	CCW Pump 32	219-224
AFW Pump 31	361-367	MCC 32	104-116
CR Fan 32	157-160	MCC 35	60-63
CR Fan 34	157-160	Chg Pump 32	149-150
ESW Pump 35	276-280	Przr Htrs 31	208-555
MCC 36C	38-96	Przr Htrs 32	208-485
		PAB Vent Fan 31	86-123
		MCC 34	46-62

Loads on Bus 6A (Emergency Diesel Generator 32)

Automatic Loads		Manual/Optional Loads	
Equipment	Load Range (KW)	Equipment	Load Range (KW)
SI Pump 33	327-330	CR Pump 32	294-296 (3)
CS Pump 32	324-332	NE SW Pump 33	276-281
RHR Pump 32	315-317 (2)	CCW Pump 33	219-224
AFW Pump 33	361-367	MCC 37	65-211
CR Fan 35	157-160	Chg Pump 33	149-150
ESW Pump 36	276-280	PAB Vent Fan 32	86-123
MCC 36B	76-104 (1)	Przr Htrs Cntl Group	277

(1) Does not include transient MOV Loads
(2) This load is reduced to 182 KW when RHR pump is in mini-flow
(3) This load is reduced to 200 KW on High-head recirculation
(4) Auto Closure loads on MCC 311 (BFD 90-1 through 90-4 and BFD 5-1 through 5-4) are transient loads

(5) Manual Load MCC 311 as required by EOP to restore Feedwater to faulted Steam Generator

TABLE 8.2-2

MAJOR BATTERY LOADS

Battery No. 31	
Inverter No. 31 (25 KVA)	2 Hours
Emergency Lighting & Control Power (17 KW)	2 Hours
Battery No. 32	
Inverter No. 32 (25 KVA)	2 Hours
Emergency Lighting & Control Power (23 KW)	2 Hours
Battery No. 33	
Control Power (1.8 KW)	2 Hours
Inverter No. 33 (25 KVA)	2 Hours
Battery No. 34	
Inverter No. 34 (7.5 KVA)	2 Hours
Battery No. 36	
Turbine Generator Emergency Oil Pump (60hp)	3 Hours
Boiler Feed Pump Emergency Oil Pump (15 hp)	3 Hours
Air Side Seal Oil Back-up Pump (25 hp)	3 Hours
PCE LCI Drives (10.875kW)	2 Hours

TABLE 8.2-3

ENGINEERED SAFEGUARDS COMPONENTS, AUXILIARY FEEDWATER AND COMPONENT COOLING SYSTEMS INITIATION, CONTROL & SEQUENCING SCHEMATICS LIST

Drawing No.	Sheet No.	Revision No.
500 B 971	5	3
	6	1
	7	2
	9	3
	10	2
	11	8
	12	4
	13	4
	14	4
	27	7
	28	7
	29	9
	31	8
	32	7
	33	8
	34	7
	37	6
	40	8
	42	7
	44	6
	45	8
	46	7
	47	6
	48	6
	51	4
	70	7
	75	10
	76	7
	78	7
	79	4
	85	4
	89	9
	90	6
	91	10
	92	5
	93	7
	94	3
	95	7
	96	9
	96A	2
	96B	0
	97	5
	98	10
	99	9

TABLE 8.2-3
(Cont.)

ENGINEERED SAFEGUARDS COMPONENTS, AUXILIARY FEEDWATER AND COMPONENT COOLING SYSTEMS INITIATION, CONTROL & SEQUENCING SCHEMATICS LIST

Drawing No.	Sheet No.	Revision No.
	105	8
	106	10
	107	4
	108	6
	110	15
	111	11
	112	15
	113	13
	114	10
	115	6
	116	9
	117	15
	117A	1
	117B	1
	119	7
	119A	1
	120	4
	121	3
	122	5
	123	9
	124	2
	124A	1
	124B	1
	124C	1
	124D	3
	124E	0
	125	3A
	125A	4
	125B	4
	126	5
	127	5
	128	4
	129	5
	130	6
	131	7
	132	7
	132A	0
	133	6
	134	7
	135	4
	136	6
	137	8
	138	8
	139	8
	140	8

TABLE 8.2-3
(Cont.)

ENGINEERED SAFEGUARDS COMPONENTS, AUXILIARY FEEDWATER AND COMPONENT COOLING SYSTEMS INITIATION, CONTROL & SEQUENCING SCHEMATICS LIST

Drawing No.	Sheet No.	Revision No.
	141	7
	152	3
	153	5
	154	5
	155	4
	160	7
	183	9
	209	1
	210	1
	211	2
113 E 301	4	7
	5	7
113 E 302	1	13
	2	10
	3	7
113 E 303	1	21
	2	6
	3	9
	4	20
	5	10
	6	11
	7	13
	8	8
9321-LL-31313	10	13
	13	4
	15	8
	15A	9
9321-LL-31343	3	14
	7	14
9321-LL-31333	1	3
	2	5
	3	4
	4	4
	6	6
	9	4
	11	3
	14	5
	15	4

TABLE 8.2-3
(Cont.)

ENGINEERED SAFEGUARDS COMPONENTS, AUXILIARY FEEDWATER AND COMPONENT COOLING SYSTEMS
INITIATION, CONTROL & SEQUENCING SCHEMATICS LIST

Drawing No.	Sheet No.	Revision No.
9321-LL-31173	1	9
	2	9
	3	12
	4	10
	5	14
	6	12
	6B	0
	7	8
	8	11
	10	5
	12	5
	13	10
	14	12
	18	7
	19	5
	20	1
9321-LL31183	1	5
	2	9
	3	10
	4	12
	5	16
	6	7
	7	9
	11	4
	12	6
	15	5
	16	3
	17	9
	18	9

8.3 MINIMUM OPERATING CONDITIONS

The minimum operating conditions for electrical systems are given in Sections 3.8.1 and 3.8.10 of the Technical Specifications.

8.4 CABLE AND PENETRATION SEPARATION

The reactor protection and engineered safety system cable circuits are divided into as many channels as is required to preserve the basic redundancy and independence of the systems. Channel separation is maintained as indicated below and is continuous from the sensors to the entrance to the receiver racks, logic cabinets, and actuation devices in such a manner that failure within a single channel is not likely to cause the loss of the basic protection system or cause a failure which would prevent actuation of the minimum safeguards devices when called for.

In general, this requires the use of four (4) protection system instrumentation channels (Section 7.2), three (3) heavy power channels, two (2) medium power channels and four (4) control channels. In addition to such channels of separation, cables are assigned to individual routing systems, in accordance with their voltage level, size and function, by means of a three digit circuit code identification.

The circuit code is broken down as follows:

FIRST CHARACTER – Voltage level

B = heavy 6900V
C = heavy 480V or DC
D = control, misc. 120V AC/DC
F = medium AC or DC power
G = vibration pick-up
H = rod control
J = instrumentation

SECOND CHARACTER – Channel

A = Channel I
B = Channel II
C = Channel III
D = Channel IV
E = Channel V

THIRD CHARACTER – Category – cables required to be in a particular channel to provide separation of redundant circuits are assigned a circuit code whose description includes the channel identification. Non-vital cables of the same voltage level, which are routed in the same channel, are assigned one of the remaining circuit codes (e.g., a safety injection pump would be assigned CA1, while a pressurizer heater would be assigned CA2. Both cables would be routed in the same tray where their paths are parallel).

There is no mixing of vital cables of the above categories in the same tray or conduit, except inside the containment building, where due to space limitations it becomes necessary to mix D and F (first character) cables of the same channel in the same tray. For the most part, these F cables are for valve motors which are less than ten (10) horsepower, and are energized only intermittently.

Conduit fill for all systems is based on standard National Electric Code recommendations.

Tray fill for 6900 volt power cables is limited to one (1) layer of cables. Tray fill for heavy 125 volt DC power cables, heavy 480 volt AC (over 100 hp) power cables, lighting panel feeders and medium power (greater than No. 12 AWG wire size) 480 volt AC cables is limited to two (2) layers of cables. Cables included for control and light power are 120 volt AC and DC control and power cables, alarm, communication, instrument transformer, and 480 volt AC power cables. In most cases, these cables are a maximum of No. 12 AWG wire size. Tray fill limitation for control and small power cables is that total cross sectional area of cables will not exceed 60% of the tray's cross sectional area. Exceptions occur where a larger wire size has been used to limit voltage drop on long runs.

Separation of channels is established throughout the plant by the use of separate trays or conduit (exceptions are documented and justified in Reference 1). In addition, whenever in a heavy power tray is located less than three (3) feet beneath any tray of a different channel a transite or marinite fire barrier is installed between the trays. A vertical barrier is installed where trays of different channels are installed less than one (1) foot apart, horizontally. Additionally, a horizontal barrier is installed where trays (other than heavy power) are installed less than one (1) foot beneath any tray of a different channel.

Fire retardant barriers have been installed between cable trays carrying cables for safety related pumps. Isolating switches are provided for fire protection of the control circuits of Diesel Generator No. 31, the control circuits for feeder breakers to 480 volt buses 2A and 3A and the tie breaker between the two buses. Safety related instrumentation have isolation switches and alternate power supplies for fire protection.

In some areas of the turbine-generator building, separation between D, F, and J cables of the same channel is by means of a 16-gauge sheet metal barrier, 4" high, within the tray. The barriers are used as a means of providing a continuous identifiable route of a given voltage level. Raceways in the turbine hall were laid out and installed specifically for the Low Pressure Steam Dump System. Among the cables in these raceways are those associated with the overspeed protection systems. The bypass system was designed to nuclear protection system criteria of redundancy, separation and reliability.

The electrical tunnels, which run from the control building past the primary auxiliary building, to the containment penetration vault, consist of two (2) concrete conduits located one above the other. Both the upper and lower tunnels are eight feet wide by eight feet high.

Channel separation in the tunnel is maintained by placing all Channel 1 trays on the left hand side of the upper tunnel (as viewed when facing north), and Channel 2 trays on the right hand side. Channel 3 and 4 trays are located on the left and right side of the lower tunnel respectively.

In the lower tunnel, two (2) 480 volt power feeders from bus 5A (to MCC 38 and to the Pressurizer Heater Backup Group 33) run with redundant cables from bus 2A. Also, one (1) 480 volt power feeder from bus 6A (to the Pressurizer Heater Control Group) runs with redundant cables from bus 3A. These feeders are not redundant and may be run in any channel provided they remain in that channel throughout their route.

The electrical penetrations are in a single area, comprised of some sixty-four assemblies (including spares). The main group of assemblies (penetration canisters) are arranged four rows high, with each row separated from another row by three (3) feet. Each assembly in a row is spaced on approximately three (3) foot centers. Each assembly contains only one category of circuit, except D and F cables previously noted as running in the same tray will also be in the same assembly. The various penetration canisters consist of units of #12 AWG, shielded twisted pairs, shielded twisted quads, #8 AWG, #2 AWG, 250 MCM, 350 MCM, triax and coax.

The penetrations are capable to withstand short circuit currents under worst case operating conditions, and to maintain their pressure boundary integrity until either the primary protection (for safety related circuits) or backup protection (for safety or non-safety related circuits) protective devices operate.

As may be seen on Plant Drawing 9321-F-30533 [Formerly Figure 8.4-1], the canisters are arranged according to separation channels, and those canisters identified by a given channel will carry only cables whose entire route are of the same channel.

In general, the separation between redundant or channelized circuits is expected to be greater than the spacing between two adjacent assemblies. However, some channels are in adjacent units and free air spacing can be expected to be twenty-eight inches or more at the face of the penetration. The control, instrument, and small power assemblies are furnished with factory installed pigtails. The cable spreading and penetration areas are in a concrete vault.

The four (4) channels of nuclear instrumentation sensor cables are in individual conduits, which are supposed from the ceiling of the two tunnels, above the trays of the same channel.

Fire Protection for the electrical system is as described in Sections 8.22 and 9.6.2.

References

1) NSE 94-3-124 ED. Revision O, "Evaluation of Cable Channelization Deficiencies."

8.5 TESTS AND INSPECTIONS

The tests discussed in this Section are designed to demonstrate that the Diesel Generators will provide power for operation of equipment. They also assure that the emergency generator system controls and the control systems for safeguards equipment will function automatically in the event of a loss of all normal 480 volt AC station service power.

The testing frequency dictated by the Technical Specifications provides for testing often enough to identify and correct deficiencies to systems under test before they can result in a system failure. The fuel supply and starting circuits and controls are continuously monitored and any faults are indicated by alarms. An abnormal condition in these systems would be signaled without having to place the Diesel Generators themselves on test.

To verify that the emergency power system does respond properly and within the required time limit when required, the following tests are performed periodically:

a) Manually initiated demonstration of the ability of the Diesel Generators to start, and deliver power up to name plate rating, when operating in parallel with other power sources. Normal plant operation will not be affected. The duration of the test shall be at least one hour to at least 50% of continuous rating.

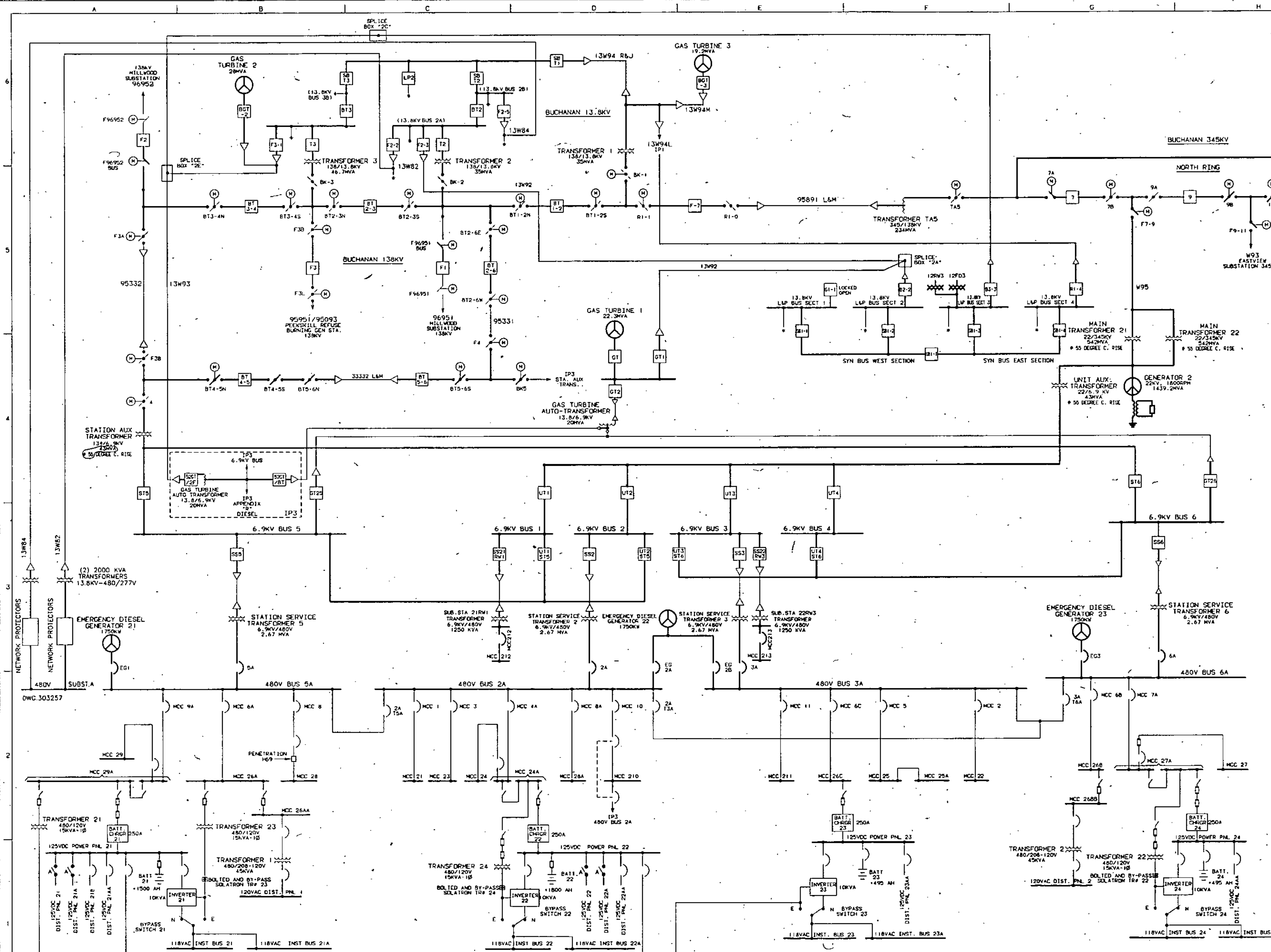
b) Demonstration of the readiness of the system and control systems of vital equipment to automatically start or restore to operation particular vital equipment by initiating an actual loss of all normal AC station service power supplies. This test is conducted as dictated by the Technical Specifications.

The starting of the diesel-generator sets can be tested from the Diesel Generator Building. The ability of the units to start within the prescribed time and to carry intended loads is checked periodically.

To verify that the 480 V safeguards bus undervoltage alarms operate properly they shall be tested monthly and calibrated every 24 months.

In addition, each diesel generator shall be inspected and maintained following the manufacturer's recommendations for this class of standby service.

EXHIBIT 4



NOTES:

1. SEE REFERENCE DRAWINGS FOR ALL ADDITIONAL CONNECTIONS TO SWITCHGEAR AND CONTROL CENTERS
2. ---* DISTRIBUTION LOAD
   A MOLDED CASE SWITCH W CAT #RHFA-2100N
   THIS SWITCH IS NOT TO BE USED TO OPEN ENERGIZED CIRCUIT
   * STATED CAPACITY IS THE NOMINAL FOR 8 HOUR DISCHARGE TO 1.75 V PER CELL FINAL.
3. FOR MORE DETAILED VERSION REFERENCE DWGS. 1410186, 1410187, AND 1360936 21

REFERENCE DRAWINGS:

480VAC SWITCHGEAR BUSES 1-LINE	A208088
MAIN AC 1-LINE	A208377
118 VAC INSTRUMENTATION BUS 1-LINE	A208502
6.9 KV 1-LINE	A231592
125 VDC POWER PANELS 1-LINE	9321-F-3008

CLASS A ITEMS
PER CI - 240 - 1

COMPUTER GENERATED DRAWING NOT TO BE HAND REVISED

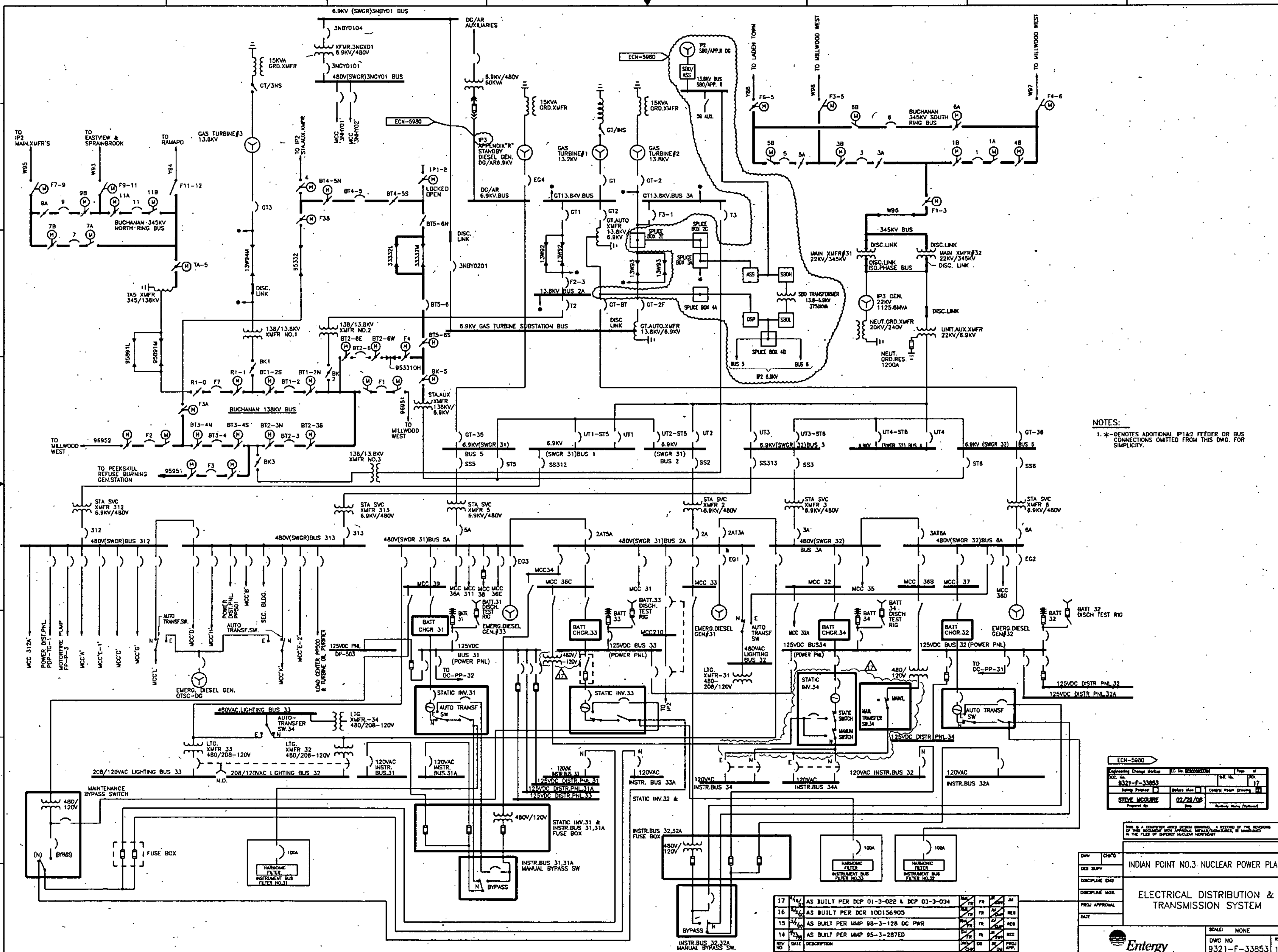
REVISION				
REVIEWER V. HYDRO 6/27/03	THIS REVISION IS NON-CLASS PER THE QAPD. UPDATED DRAWING PER CR-IP2-2002-11039 RELEASED FOR RECORD P/N 69901-AF 6/27/03 SL/YN	F. HOFFMAN (DESIGN ENG)	A. KAFFASHAN (DISC. ENG.)	G. BLENKLE 9/12/91 (ENG. MGR.)

TITLE: ELECTRICAL DISTRIBUTION AND TRANSMISSION SYSTEM - UFSAR FIG. NO. 8.2-1 & 8.2-2

Con Edison — STATION: INDIAN POINT

DRWN BY BOWE/WATKINS — SCALE NONE — DWG. NO. A250907-21 DZ

EXHIBIT 5



NOTES:

1. *-DENOTES ADDITIONAL IP1&2 FEEDER OR BUS CONNECTIONS OMITTED FROM THIS DWG. FOR SIMPLICITY.

REV	DATE	DESCRIPTION
17		AS BUILT PER DCP 01-3-022 & DCP 03-3-034
16		AS BUILT PER DCR 100156905
15		AS BUILT PER MMP 98-3-128 DC PWR
14		AS BUILT PER MMP 95-3-287ED

REVISIONS

INDIAN POINT NO.3 NUCLEAR POWER PLANT

ELECTRICAL DISTRIBUTION & TRANSMISSION SYSTEM

Entergy

SCALE: NONE

DWG NO 9321-F-33853 REV 17

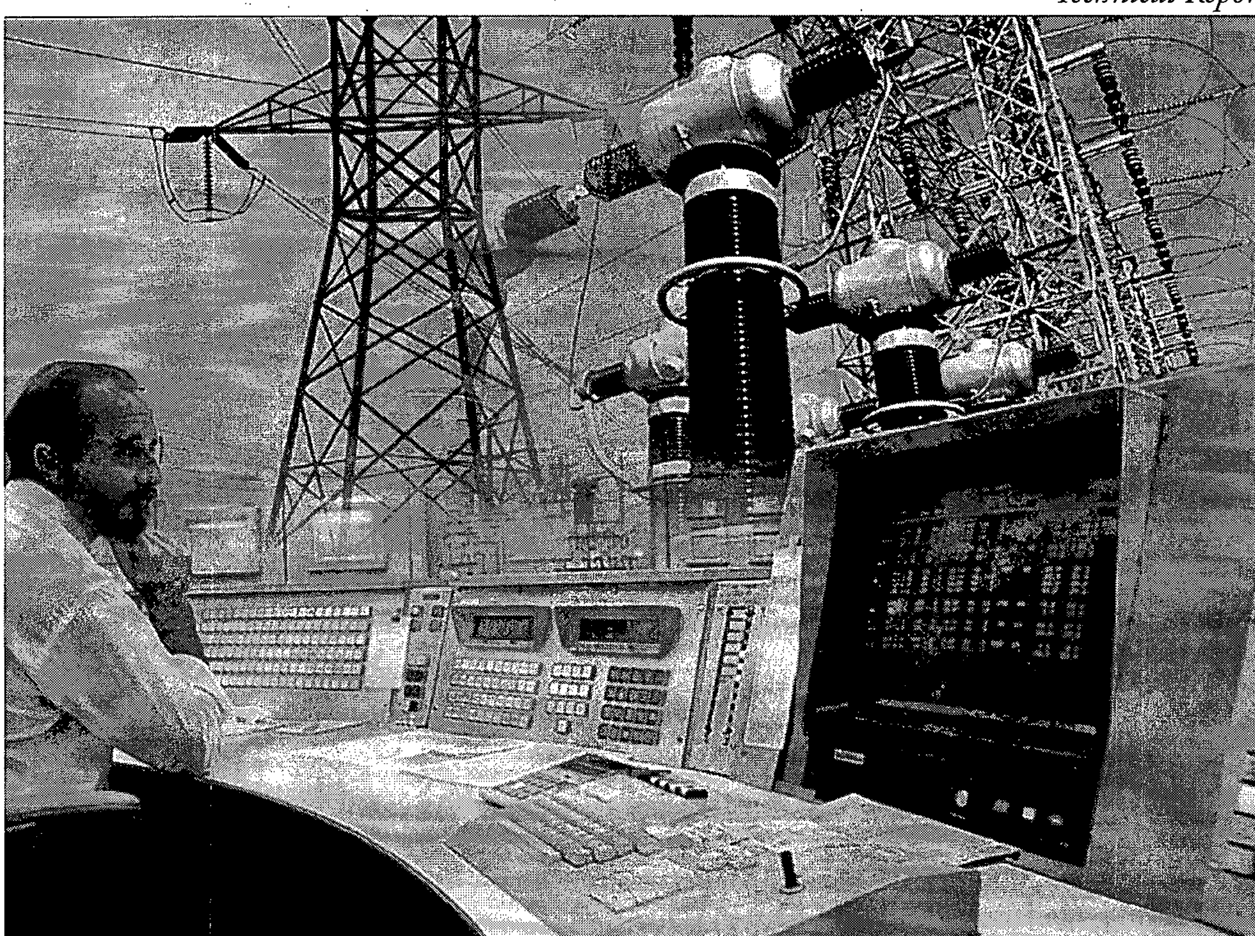
TYPE A (FSAR)

EXHIBIT 6

ELECTRIC POWER RESEARCH INSTITUTE

Plant Support Engineering: Large Transformer End-of-Expected-Life Considerations and the Need for Planning

Technical Report



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Plant Support Engineering: Large Transformer End-of-Expected-Life Considerations and the Need for Planning

1013566

Final Report, December 2006

EPRI Project Manager
G. Toman

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PRODUCT DESCRIPTION

The purpose of this report is to alert plant managers and component/system engineers of the point in life of large, oil-filled transformers when long-term planning or contingency planning is desirable to preclude end-of-life failure or to make its impact manageable. This report defines the expected life of large, oil-filled transformers and specifies actions that can be taken to identify the approach of end-of-life failures or to reduce the cost of responding to them.

Results and Findings

Based on expert input, the report identifies the onset of end-of-life failure mechanisms and provides condition monitoring techniques that can be used to determine if the transformer is succumbing to failure. It also conveys the lead times that the condition monitoring technique can provide between the point of detection and the point of near or complete failure. Finally, the report covers a discussion of the logistics related to replacement of a transformer including the length of time required under varied scenarios. This information is useful in determining the need for contingency or long-term planning for an aging transformer.

Challenges and Objectives

The report is aimed at plant managers and component/system engineers responsible for equipment reliability and assessment of the impact of failures on plant operations. The report indicates the time at which long-term aging mechanisms can result in catastrophic failures and provides insights in identifying the onset of such conditions and the impacts of responding to an in-service failure. Given an understanding of this information, the plant staff can then assess alternatives such as preparing for replacement or refurbishment of the transformer, improvement of condition monitoring systems, and/or the development of contingency plans should a failure occur.

Applications, Value, and Use

This is the first End-of-Expected-Life report. There is one more in development for generators, with three more schedule to be developed in 2007. Depending on the industry response to these documents, EPRI will generate reports for further components and systems, modify the content of the reports, or determine that no further reports are needed. The reports are expected to be of use to personnel responsible for long-term planning for operation of equipment and should help such personnel to determine when actions are needed to preclude end-of-life failures.

EPRI Perspective

Life cycle management (LCM) and long-term planning efforts have generally focused on resolving issues with systems and components that have caused continuous problems for plants. This project provides the impetus for beginning the planning for prevention and mitigation of equipment failures, mainly focusing on equipment that has generally provided trouble-free service but is likely to degrade and fail due to long-term aging. With information on expected life, monitoring techniques, and logistics issues, the need for long-term planning can be determined. Once the need has been confirmed, existing utility methods for assessment of alternatives or Electric Power Research Institute (EPRI) economic decision-making tools such as *Life Cycle Management Value Planning Tool (LcmVALUE) Code* (EPRI product 1003455) and *Lcm Plato Code* (EPRI product 1002860) may be used to support planning. Further planning information for transformers may be found in the *Life Cycle Management Planning Sourcebooks, Volume 4: Large Power Transformers* (EPRI report 1007422). Additional discussions of preventive maintenance and condition monitoring that may be applied throughout the life of the transformer are contained in the *Preventive Maintenance Database* (EPRI product 1011923) and the *Power Transformer Maintenance and Application Guide* (EPRI report 1002913).

Approach

The goal of the project was to provide decision-making information to determine when a long-term plan or contingency plan is needed as transformers approach the expected end of life. The report has purposely been kept short so that users could readily understand key issues and be ready to quickly make decisions concerning long-term planning for large transformers. The report uses tables to provide key information on expected life, condition monitoring techniques useful for detecting the onset of end-of-life conditions, key stressors that would shorten the expected life, and logistics associated with replacement during a planned outage or upon failure. Discussions have also been kept purposely short. References are provided to allow readers to obtain more detailed information if desired, much of which is contained in other EPRI reports.

Keywords

Expected life
Large oil-filled transformers
Logistics of transformer replacement
Condition monitoring

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1 INTRODUCTION

With the implementation of license renewal, nuclear plant staffs must determine if the lives of long-lived components are sufficient for operating 60 or more years. Their considerations must take into account the actions necessary to preclude in-service failures of major components or contingency plans to ensure as rapid a return to service as possible should a failure occur.

The purpose of this report is alert plant managers and component/system engineers of the point in life of large transformers when long-term or contingency planning is desirable to preclude end-of-life failure or to make its impact manageable. This report defines the expected life of large, oil-filled transformers and specifies actions that can be taken to identify the approach of end-of-life failures or to reduce the cost of responding to them. The transformers covered by this report are large, oil filled transformers with oil coolers, such as main step-up transformers, substation auto transformers between substations with different transmission voltages, and auxiliary and startup transformers.

Expected life is defined as the time from start of service to the point when the basic periodic maintenance regime needs to be changed to one of a major refurbishment or replacement of the equipment to preclude catastrophic failure of a component. In this report, the expected life has been determined by polling experts on large, oil-filled transformers. The experts provided estimates of the point through which transformers receiving appropriate maintenance and condition monitoring would be expected to provide satisfactory service. After that point, a catastrophic failure would be more likely. These predictions of expected life will help utilities determine when heightened monitoring and maintenance, refurbishment, or replacement would be prudent. Figure 1-1 provides the basic concept of expected life and its relationship to the need for planning. Reviewing the need for a long-term and/or contingency plan well before the end of the expected lives of large transformers can be valuable. Knowing the condition and location of spare transformers, the lead times before failure provided by condition monitoring techniques, the availability of transportation routes, and the logistical and outage issues associated with transformer failures may indicate that having long-term or contingency plans in place early is appropriate.

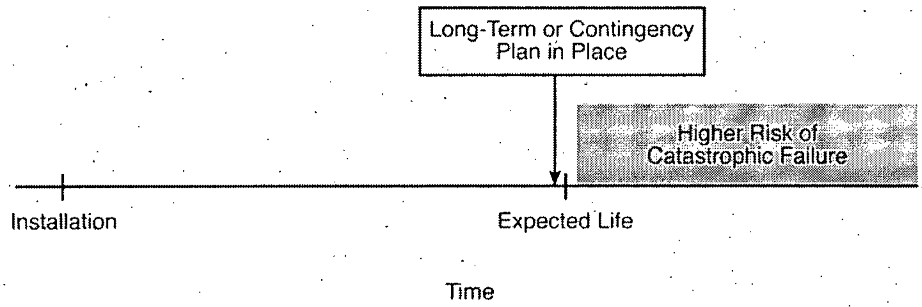

Figure 1-1
Expected Life and Long-Term Planning

The value of expected life estimates for equipment results from avoiding or limiting the effect of catastrophic failures from degradation mechanisms not addressed by normal maintenance. Expected life estimates will make plant technical staff more aware of the need to consider alternative equipment reliability strategies beyond normal maintenance regimes. It will also help technical staff support business cases indicating that investments in plant equipment are warranted.

This report has been generated to help in determining the need for long-term plans; it is not meant to be a basis for the plan or for determining the types of normal maintenance and monitoring that should be applied to large transformers. Other EPRI reports and methods have been developed for those purposes. For example, *Life Cycle Management Planning Sourcebooks, Volume 4: Large Power Transformers* (EPRI report 1007422) [1] provides a discussion of the overall life cycle management (LCM) planning process, presents transformer failure data for the industry, discusses appropriate maintenance, and monitoring, and discusses possible alternative plans. This information can be used to compare to plant-specific information in order to determine how plant transformers have fared with respect to the overall industry. The report describes sources of plant-specific data and the means of evaluating that data. *Life Cycle Management Value Planning Tool (LcmVALUE) Code* (EPRI product 1003455) [2] provides a program that may be used to perform economic assessments of alternative plans. Figure 1-2 shows the context for the use of this report.

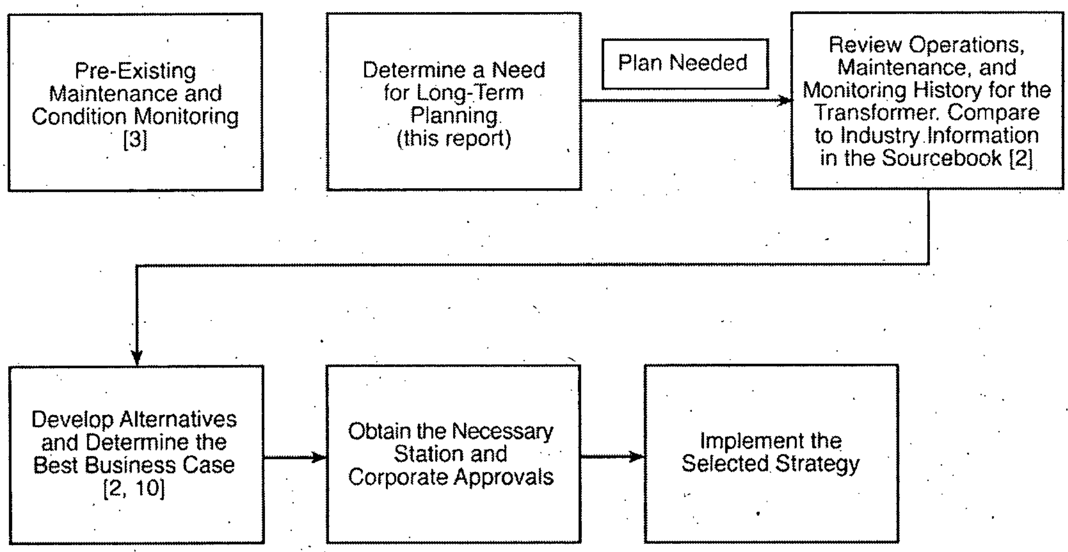

Figure 1-2
Context of Expected-Life Issues

In addition to identifying the expected life of long-lived transformer subcomponents, this report identifies condition monitoring techniques that will be useful for identifying the onset of failure mechanisms that could lead to a catastrophic failure related to end-of-life failure mechanisms. The degree to which the condition monitoring results provide a leading indication is provided as well. This lead time is supplied for use in considering contingency planning and/or the need for replacement or refurbishment before or at the end of expected life.

The report describes the logistics related to equipment replacement or refurbishment and/or the development of contingency plans. These logistics discussions provide an estimate of time for the procurement of a replacement transformer and the time and cost of moving a spare in place and readying it for service. For large transformers, these times can be quite long, leading to extended outages.

With the information in the report, a utility can make a decision on the most appropriate action to take and the expected costs associated with the action. A utility may wish to proceed with the development of an LCM plan as defined in *Nuclear Plant Life Cycle Management Implementation Guide* (EPRI report TR-106109) [3] and supported by EPRI report 1007422 [1] to develop contingency plans or to implement another form of long-term planning.

2 EXPECTED-LIFE CONSIDERATIONS

Table 2-1 provides the expected-life of long-lived transformer components that upon failure could ultimately cause either a long-term or complete loss of use. Many other subcomponents have shorter lives, but diligent maintenance and replacement practices allow long-term use of the transformer. The listed expected lives indicate the point to which there is reasonable certainty that the transformer can perform its function. Thereafter, without intervention, the probability of catastrophic failure increases from long-term degradation.

The life expectancies listed in Table 2-1 are based on expert opinion rather than statistical data, which are not available. The life expectancies are provided to support planning activities and to indicate the point at which planning is desirable for additional monitoring and maintenance, refurbishment, or replacement as appropriate.

Estimating Station-Specific Expected Lives

The transformer component expected-life ranges in Table 2-1 are based on the assumption that reasonable maintenance, inspection, and monitoring activities have been performed throughout the service life of the transformer and that appropriate corrective actions have been taken in response to the inspection and monitoring findings. The Degradation Influence and Preventive Maintenance Supporting Expected Life information is provided to support station-specific evaluation of the part of the Life Expectancy range that applies to the station's transformer(s). It is not the intent to indicate that the listed condition monitoring techniques should be applied only at or near the end of expected life. Many of the listed techniques and others are expected to be used throughout the life of the transformer in order to identify failure mechanisms that could lead to early failure. For example, dissolved combustible gas analysis is a condition monitoring technique that should be applied to transformers throughout their lives. Other techniques, such as infrared thermography, are useful in detecting abnormalities, such as a clogged heat exchanger or a cooling fan that is running in reverse. The information in Table 2-1 focuses on the identification of long-term aging mechanisms that could lead to catastrophic failure rather than shorter-term mechanisms that are readily identifiable, correctable, and generally will not lead to failure if corrected in a reasonable period of time.

Life expectancy of these major subcomponents can be affected by the lack of maintenance performed on the transformer and by grid/electrical system disturbances, such as through faults and voltage surges. Maintenance activities that can improve the length of expected life are listed in Table 2-1 and short descriptions of these activities are given in the following sections. Detailed descriptions of these and other useful preventive maintenance tasks are discussed in

EPRI report 1007422 [1] and *Power Transformer Maintenance and Application Guide* (EPRI report 1002913) [4]. Evaluation of the maintenance and operating experience for a transformer will help determine whether a shorter or longer expected life is likely.

Operating the transformer under higher than normal stresses, such as over temperature or excessive operating voltages, will shorten the life of the transformer. Table 2-1 indicates the stresses that influence and could shorten expected life. Evaluating the historical incidences of elevated stressors will also help improve the estimation of the expected life for a specific transformer. For example, if the transformer is oversized and operated well below normal load limits, the thermal life of the transformer would be significantly longer. Conversely, if the transformer coolers function poorly due to lack of maintenance and the transformer operated for long durations during summer at or above normal operation thermal limits, the thermal life would be shorter. This review is not meant to definitively identify the expected life, but rather to determine if adverse conditions that could shorten life have occurred. Through faults or bushing faults are significant factors that would stress winding and core integrity. If the transformer experienced a number of through faults, expected life could be shortened due to the loosening or breakage of internal components.

Table 2-1 was also developed under the belief that the oil has also been monitored for moisture content and that any significant increases in moisture content as indicated by oil analysis will be corrected by identifying the source of ingress and repairing it. It also assumes that the oil was conditioned as needed to preclude breakdown of the oil and the insulating oil.

Table 2-1
Expected Life, Diagnostics, and Logistics for Large Transformers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods [Confirmatory] (see Note 1)**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Potentially Catastrophic											
Winding insulation	Electrical breakdown	Thermal aging; contamination; worsened by high operating temperature	Clean coolers; maintain cooling fans and verify direction of flow; verify circulating pump operation; verify single core ground; monitor transformer temperature; calibrate temperature monitor.	30–40 years	0–1 1/2 years or more (see Note 2)	Gas-in-oil analysis (high CO and CO_2 with H_2 and without hydrocarbons indicates paper degradation; high CO and CO_2 with CH_4 C_2H_6 and C_2H_4 indicate overheating of insulation.) [Furan in oil analysis (insulating paper assessment)]	Techniques are well established and linked to transformer failure mechanisms.	If transformer fails, low likelihood of repairability. If removed from service before failure, possibly repairable, but may require shipping to service facility.	Not readily definable	Oil must be removed from transformer; breathable air needed for internal inspection.	See Table 4-1
Internal bus supports	Failure of under-designed supports leading to tracking to ground	Multiple faults in adjacent equipment and transmission lines	No useful maintenance. Repair upon identification.	20–30 years [2]	Days to months	Gas-in-oil analysis (H_2 or C_2H_2 [acetylene] indicates arcing. C_2H_2 is indicative of high-intensity arcing and is more serious.) [Acoustic partial discharge detection]	Techniques are well established.	If transformer fails, moderate likelihood of repairability. If removed from service before failure, very likely to be repairable on site.	4–8 weeks	Oil must be removed from transformer; breathable air needed for internal inspection. After repairs, lengthy oil reconditioning needed. Transformer may have to be removed from tank to repair (see Note 3).	If failed, see Table 4-1. If not failed, replacement unlikely to be needed.

Table 2-1 (continued)
Expected Life, Diagnostics, and Logistics for Large Transformers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods [Confirmatory] (see Note 1)**	**Diagnostic Effective-ness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Core	Multiple grounds; leads to circulating currents in core and overheating	Assembly error; vibration; loss of insulation between core and tank	Identify additional grounds possible; no useful maintenance.	40 years [2]	Not available	Transformer temperature; gas-in-oil analysis [Core insulation resistance]	Techniques are well established.	If transformer fails, low likelihood of repairability. If removed from service before failure, very likely to be repairable on site.	4–6 weeks	Oil must be removed from transformer; breathable air needed for internal inspection. After repairs, lengthy oil reconditioning needed. Transformer may have to be removed from tank to repair (see Note 3).	If failed, see Table 4-1. If not failed, replacement unlikely to be needed.
Core	Loss of ground leading to static charge buildup and arcing	Assembly error; vibration	Core grounding verification possible; no useful maintenance.	40 years [2]	Not available	Transformer temperature; gas-in-oil analysis (H_2 or C_2H_2 [acetylene] indicates arcing. C_2H_2 is indicative of high-intensity arcing and is more serious.) [Acoustic partial discharge detection]	Techniques are well established.	If transformer fails, low likelihood of repairability. If removed from service before failure, very likely to be repairable on site.	4–6 weeks	Oil must be removed from transformer; breathable air needed for internal inspection. After repairs, lengthy oil reconditioning needed. Transformer may have to be removed from tank to repair (see Note 3).	If failed, see Table 4-1. If not failed, replacement unlikely to be needed.

Table 2-1 (continued)
Expected Life, Diagnostics, and Logistics for Large Transformers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods [Confirmatory] (see Note 1)**	**Diagnostic Effective-ness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Core and winding	Loosening; leading to damage of lamination insulation or chafing of insulation	Multiple faults in adjacent equipment and transmission lines; vibration	N/A	40 years [2]	Relatively rare event	Increased 60 Hz noise, acoustic monitoring. [Frequency response analysis - an off-line test]	Techniques are well established.	If transformer fails, low likelihood of repairability. If removed from service before failure, very likely to be repairable.	Depends on severity of damage to insulation and laminations. May require repair in service shop.	Oil must be removed from transformer; breathable air needed for internal inspection. After repairs if done locally, lengthy oil reconditioning needed.	Replacement may be necessary to correct damage. See Table 4-1.
Oil-filled bushings	Insulation failure	Internal contamination; low oil; voltage surge (lightning); manufacturing problem; cracked porcelain	Inspect and clean external bushing surfaces; repair oil leaks; replace if leak cannot be repaired; replace if porcelain is cracked or chipped.	>15 years	If externally contaminated, may fail quickly, especially in wet conditions. Internal issue may worsen relatively rapidly.	External visual inspection for contamination and oil leakage. Oil level verification. Infrared thermography. [Power factor testing]	Techniques are effective and well established.	If deteriorated or failed, likely to be replaceable. If failure induces internal fault, low likelihood of repairability.	Days to a week	N/A	N/A
Solid bushings	Insulation failure	Chipped or cracked porcelain	Inspect and clean external bushing surfaces; replace if porcelain is cracked or chipped; replace on unacceptable power factor test.	>15 years	If externally contaminated, may fail quickly, especially in wet conditions. Internal issue may worsen relatively rapidly.	External visual inspection for contamination. [Power factor testing]	Techniques are effective and well established.	If deteriorated or failed, likely to be replaceable. If failure induces internal fault, low likelihood of repairability.	Days to a week	N/A	N/A

Table 2-1 (continued)
Expected Life, Diagnostics, and Logistics for Large Transformers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods [Confirmatory] (see Note 1)**	**Diagnostic Effective-ness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Conservator tank	Bladder failure allowing moisture contamination of oil and paper insulation	Thermal aging of rubber bladder	Periodically inspect bladder or diaphragm. Respond to bladder failure relay.	40 years [2]	Failure not immediately damaging.	Gas-in-oil analysis (moisture and air). [Physical inspection]	Techniques are effective and well established.	Repairable on site. Partial drainage of oil necessary.	4 weeks; possibly less	N/A	Should not be necessary if corrected within a reasonable period.
Tank	Weld failure/ leakage	Corrosion/ untreated external rust	Remove rust and paint as appropriate.	40 years + [2]	Slow process	Visual external examination.	Easy to detect and correct.	Clean rust and repaint area.	Easy to correct at unit outage	N/A	N/A

Note 1. Not all condition monitoring methods are listed. Commonly used methods with reasonable ability to detect the listed end-of-life failure mechanism are listed. See discussion.

Note 2. The time from leaving the "normal state" to failure assumes at least yearly diagnostics. If continuous on-line diagnostics are employed, earlier detection is possible, and months of earlier warning may be possible.

Note 3. Removal of the transformer from the tank is generally done only at a repair facility. Accordingly, the time to repair can be greatly extended by having to ship the transformer to and from the repair facility.

Major End-of-Life Failure Mechanisms and Factors That Affect Them

Table 2-1 lists a number of end-of-life failure mechanisms and factors that affect them. The following sections discuss this information. The discussion of condition monitoring tests is not meant to be all inclusive, and many other useful tests exist. The additional tests and their usage are described in *PMB C/S 1.5 Preventive Maintenance Basis Database Client/Server, Version 1.5* (EPRI report 1011923) [5] and EPRI report 1002913 [4]. The basis for intervals for transformer maintenance and inspections under severe and mild operating conditions are provided by EPRI report 1002913 [4].

The following discussions are provided to indicate the types of preventive maintenance required to retard the degradation when a means of preventive maintenance exists. The discussions also indicate condition monitoring activities that detect the adverse condition. For a number of the problems, removal of the transformer from service and the performance of internal maintenance will be necessary. Some problems will require the transformer to be shipped to a maintenance facility where the internals can be removed for repairs or refurbishment.

Winding Insulation Degradation

The winding insulation of these transformers is comprised of heavy craft paper between layers of the windings, between the windings, and between phases of multi-phase transformers. Over long periods of time, the effects of temperature will cause the cellulose in the craft paper to break down. The rate of degradation is logarithmically proportional to temperature. Accordingly, a transformer whose windings operate at or near the normal operating temperature limit for long periods will age much faster than one that operates 10 to 20°C or more lower than the rated normal operating temperature. If a transformer is known to have to operate near normal operating limits each summer, cleaning the coolers, verifying the operability of the cooling fans, and verifying the direction of flow prior to each summer operating period is very important. The verification of cooling oil pump flow is also important. Infrared assessment of the coolers will indicate if there is flow blockage within a cooler. Verification of cooler function is especially important for locales with long, hot summers and grids having summer peaking conditions. Thermal aging is expected to be slower for locations with lower summer temperatures and winter peaks. EPRI report 1011923 [5] indicates that cooler maintenance and calibration of indicators, such as the temperature indicator, can affect the failure rate by 50% or more. Infrared imaging is particularly useful in identifying problems with the cooling system.

In addition, localized heating within the transformer can cause rapid localized damage to the insulating paper. Conditions such as eddy current heating in the core, arcing, and loose connections can cause localized heating and rapid deterioration of insulating paper in the vicinity of the problem. If any of these conditions are recognized by dissolved combustible gas assessments or other monitoring methods, appropriate actions to monitor the condition and to repair it are recommended. Furan analysis indicates when the paper insulation is deteriorating significantly from either localized thermal aging or general aging from long-time thermal conditions.

While not listed in Table 2-1, wetting of the paper insulation will greatly reduce its capability to withstand voltage. Wetting would occur if there is an air or oil leak that allows the transformer to breathe in moisture. If a significant level of water is detected in the oil, the leak should be repaired as soon as possible, and the oil should be treated to reduce moisture content, which in turn reduces the moisture content of the paper. Moisture intrusion is not an end-of-life degradation mechanism. Moisture intrusion could happen early in life if seals fail or are improperly installed. If the cause is not corrected, continued ingress of moisture could cause an early failure.

Internal Bus Supports

Busses in the transformers connect the windings to the bushings. These busses need to be supported in a manner that prevents the busses from moving significantly upon inrush and fault currents. In some transformers, the bus supports were underdesigned such that they could break or crack upon being subjected to through faults. Failure mechanisms that could result are tracking paths between the bus and ground through the crack area or shorting of the bus to surrounding conducting surfaces during the next through fault.

There are no effective preventive maintenance activities for underdesigned bus supports. However, should arcing or overheating be indicated by dissolved gas analysis or other means, further investigation, confirmatory monitoring, and repairs should be implemented. EPRI report 1011923 [5] indicates that dissolved gas analysis is an important test method for assessing transformer conditions. Partial discharge evaluation is another possible way to detect bus support failure if tracking is occurring.

A transformer with underdesigned bus supports is sensitive to through fault currents that cause the busses and windings to thrash. Accordingly, evaluating the number of fault events that have occurred in the electrical vicinity of the transformer will provide information indicating where this failure mechanism is likely to occur. Also, certain vintages of transformers are known to be prone to this type of problem. Industry experience with similar designs and manufacturers can provide insights for any specific transformer.

Loss of Core Ground or Multiple Core Grounds

The transformer core is grounded to preclude buildup of static charge on the core that could cause a flashover to the windings. Accordingly, loss of the core ground is an unacceptable condition. At the same time, the core is composed of layers of sheet steel that are insulated from each other in order to prevent eddy currents from overheating the core and, in turn, the winding. Multiple grounds on the transformer core could short the core layers and allow eddy currents to cause heating of the insulation and windings. Although a fairly rare condition, multiple grounds on the core would need to be corrected. The severity of the overheating can be determined by the results of the dissolved combustible gas analysis. While there are no useful preventive maintenance actions for loss of ground or multiple grounds, testing of the core ground system is possible during transformer shutdown. Depending on how and where the core is grounded in the design, the ground system may be repairable locally, or the transformer may have to be moved to a repair shop to allow the windings to be removed from the tank. EPRI report 1011923 [5] lists core ground assessment as part of calibration and testing that would change the failure rate by 50% or more if not performed.

Loss of the core ground or the occurrence of additional grounds is associated with the number of instances of through fault currents. Evaluating the number of fault events that have occurred in the electrical vicinity of the transformer will provide information indicating where this failure mechanism is likely to occur.

Loosening of Core and Winding

Many clamps and wedges are used to construct a transformer. These clamps and wedges are constructed of insulating fiber board. If these wedges come loose due to the trashing of the coils during through faults, the winding and/or core can loosen, leading to chafing of the insulation, and could lead to failure. There are no preventive maintenance activities that will preclude such loosening; however, the use of periodic acoustic or vibration monitoring following a major through fault could identify loosening. Assessment of the importance of an increase in vibration and the identification of the location of the problem within the transformer will require a transformer expert and/or the support of the manufacturer. EPRI report 1011923 [5] indicates that not performing vibration analysis will cause less than a 25% increase in the failure rate. However, should faults occur close to a large transformer causing a large through current, acoustic monitoring after a return to service would determine if significant loosening of transformer internal components has occurred. The more numerous the number of through faults, the higher the likelihood that loosening could be a problem for a transformer as it nears end of life.

Insulation Failure of Bushings

Maintaining the electrical condition of transformer bushings is very important. Bushings have shorter lives than the overall transformer. Their failure can cause severe to catastrophic damage to the transformer winding. Paying close attention to the condition of the bushings is a key factor in ensuring that the transformers attain their expected lives.

The two basic types of bushings are oil-filled and solid insulation. Both may be subject to external flashover if the external surface becomes contaminated or significantly damaged. Soot, dirt, and salt spray are some of the causes of contamination. Cracks or the loss of segments of the bushing petticoats could result in a reduction of their ability to withstand surge voltage. Visual inspection and cleaning are effective means of detecting physical problems and eliminating contaminants that build up on the surface over time. In some areas where contamination levels are high, surface treatments, such as silicone grease, may be used to absorb contaminants as they deposit on the bushing surface, thereby retaining the surface insulation length that is desired.

Oil-filled bushings are filled with insulating oil. Possible dominant failure mechanisms include the leakage of oil from the bushing into the transformer tank with air replacing the oil, and the loss of the top seal allowing water and moisture to enter. Loss of oil is detectable by the use of infrared thermography. The oil-filled section will run warmer due to better heat transfer than the air-filled section. If moisture is entering the bushing, the oil level is likely to be higher than required due to the fact that water is heavier than oil.

The insulation of solid bushings may degrade with time. Periodic power factor testing will identify such deterioration. Such tests require the transformer to be out of service and disconnected. EPRI report 1011923 [5] indicates that this activity should be part of the normal periodic testing and calibration for the transformer.

Conservator and Transformer Breathing System Failures

Atmospheric pressure changes frequently, and a transformer must be allowed to breathe to preclude over-pressure and vacuum conditions in the tank. Transformers with conservator tanks generally have bladders or diaphragms in the conservator with atmospheric pressure on one side and transformer oil on the other in order to allow for changes in atmospheric pressure. Failure of the bladder or diaphragm could lead to rapid moisture buildup in the oil and winding insulation. These systems generally have a desiccant on the breather. Some conservators may have just a breather with a desiccant and not employ a bladder or diaphragm. In all cases, maintaining the desiccant helps preclude moisture ingress. Oil analysis can also be used to detect water ingress. Inspection of the condition of bladders and diaphragms when used should be part of the normal periodic maintenance activities. EPRI report 1011923 [5] indicates that evaluation of the desiccant color should be performed during system engineer walkdowns every three months and that such walkdowns are critical to long life of the transformer. The PM Database indicates that oil analysis should be performed on an annual basis.

Tank Leakage

Seal and gasket leakage should be detectable by walkdowns and oil analysis. Tank seam leakage should not be a significant problem if the seams and welds are inspected for rust. Any noticeable rust on the tank should be removed. The affected area of the tank should then be treated and painted. Leakage of tank welds would be likely only if rusting were allowed to go unchecked for extremely long periods.

The tank could rupture upon a fault internal to the transformer. Such a fault is likely to cause irreparable damage to the transformer, making the transformer unusable.

3
CONDITION MONITORING RELATED TO END OF EXPECTED LIFE

As large, oil-filled transformers reach the point where long-term aging is causing a higher likelihood of failure, condition monitoring becomes increasingly important. Section 5 of EPRI report 1007422 [1], Section 6 of EPRI report 1002913 [4], and Section 6 of *Transformer: Basics, Maintenance, and Diagnostics* [6] provide discussions of condition and performance assessment methods that may be performed both on line and off line. This section discusses tests for assessing end-of-life conditions. The discussion is not all inclusive. Other tests exist and may be useful in assessing end-of-life conditions.

Table 3-1 lists a diagnostic method and a confirmatory condition monitoring method for each of the failure mechanisms that could lead to catastrophic failure due to advanced aging. The table also indicates the range of the possible periods from time of first detection of an abnormal condition to a time near or at the failure point.

In EPRI report 1007422 [1], gas-in-oil analysis is listed as a primary means for determining the nature of the problems within a large, oil-filled transformer. Gas-in-oil analysis can indicate deterioration of the paper insulation, overheating of an insulated part of a transformer, overheated metal components, partial discharges, water in contact with the steel core, overheating of the core, and arcing. Different gases and concentrations of gases allow differentiation between deterioration types. Table 3-1 indicates the relationship of the gases to advanced aging failure mechanisms.

Gas-in-oil analysis can be judged on a total dissolved combustible gas basis or on the basis of individual gases in the oil. Table 5-1 of EPRI report 1007422 [1] lists the limits for total dissolved gas concentrations in the transformer oil for four conditions ranging from normal through excessive degradation. It also lists the limits for individual gases that are indicative of specific failure modes. Based on *Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers* [7], Table 3-2 provides these total and individual gas limits. Note that the limits for some gasses are much smaller than for others. The limit for carbon dioxide concentrations can be a factor of 7 times higher than the limit for carbon monoxide. Because carbon dioxide can be so dominant, its concentration is not counted in the total dissolved combustible gas limit. When one or more dissolved combustible gasses exceed normal operation limits, it is important to increase the frequency of testing and to determine the rate of change in the presence of the gases. Observing the change in the rate of gas generation will indicate whether the degradation is proceeding slowly or accelerating. Evaluation of the individual gases is recommended because observation of only the total dissolved combustible gas could mask the changes to acetylene, ethane, and ethylene. Acetylene is indicative of severe arcing in the transformer. Ethane and ethylene, along with methane, are indicative of breakdown of the mineral oil.

Per "Nuclear Electric Insurance Limited (NEIL) Transformer and Switchyard Standards" [8] presentation, NEIL uses similar conditions to those listed in Table 3-1, but indicates that at Condition 4, NEIL will review continued insurance coverage if the utility/plant operator decides to continue operation.

Table 3-2 provides recommendations for rate of gas generation limits developed by the Bureau of Reclamation for their large transformers [6]. Evaluating the rate of generation of combustible gases should provide earlier warning that deterioration is progressing rapidly and would indicate a more immediate need for action than by assessing quantities of dissolved gas alone. For example, if the dissolved hydrogen increased from 100 to 500 ppm in a six-month period, dissolved gas analysis would indicate Condition 2 (Greater than normal, begin analysis [Table 3-1]). Rate of gas generation analysis would take the difference from the previous measurement (400 ppm) and divide it by 6 months to get 67 ppm/month, which would indicate that the transformer is in Condition 4 (Action [Table 3-2]). In this case, the rate of gas generation would indicate that more intense study and action is required than just the analysis of gas quantity.

Table 3-1
Dissolved Combustible Gas Action Limits (ppm)

Condition	H_2 Hydrogen	CH_4 Methane	C_2H_2 Acetylene	C_2H_4 Ethylene	C_2H_6 Ethane	CO Carbon Monoxide	CO_2 Carbon Dioxide	TDCG (see Note 1)
1. Normal operation.	100	120	35	50	65	350	2,500	720
2. Greater than normal, begin analysis.	101–700	121–400	36–50	51–100	66–100	351–570	2,501–4,000	721–1,920
3. High level of insulation degradation. Sample frequently to establish trend of gas evolution.	701–1800	401–1000	51–80	101–200	101–150	571–1,400	4,001–10,000	1,920–4,630
4. Dissolved gas in this range indicates excessive decomposition. Continued operation could result in failure of the transformer.	>1800	>1000	>80	>200	>150	>1,400	>10,000	>4,630

Note 1. Total dissolved combustible gas excluding CO_2.

Table 3-2
Dissolved Combustible Gas Rate of Gas Generation Limits (ppm generation/month) [6]

Condition	H_2 Hydrogen	CH4 Methane	C_2H_2 Acetylene	C_2H_4 Ethylene	C_2H_6 Ethane	CO Carbon Monoxide	CO_2 Carbon Dioxide
1. Good	<10	<8	<.5	<51	<8	<70	<700
2. Fair	>9 <30	>7 <23	>.4 <1.5	>50 <101	>7 <23	>69 <220	>699 <2100
3. Poor	>29 <50	>22 <38	>1.49 <2.5	>100 <201	>22 <38	>219 <350	>2099 <3500
4. Action	>49	>37	>2.49	>200	>37	>349	>3499

Confirmatory and Alternate Diagnostic Methods

In addition to the commonly used diagnostic for identifying end-of-life failure mechanisms, Table 2-1 provides a test for confirming the existence of the presence of the failure mechanism. Other confirmatory tests may be used as well. Further tests may be identified from EPRI report 1002913 [4]. Short descriptions of the confirmatory tests are provided here.

Furan in Oil Test

When transformer insulating paper decomposes thermally, oil-soluble chemical compounds are released in addition to carbon monoxide and dioxide gases. These are furanic compounds with 2-furfuraldehyde being the principal one [4]. The furanic compounds are identified through the use of high-performance liquid chromatography. Normally, operating transformers have less than 100 ppb (parts per billion) of furans. Table 6 of *Transformer: Basics, Maintenance, and Diagnostics* [6] provides further detail on furan limits.

Acoustic Partial Discharge

Arcs and partial discharges within the transformer give off acoustic signals that travel through the oil and may be detected on the outside surface of the transformer tank. To detect arcs and partial discharges, multiple acoustic sensors are attached to the outside of the transformer. Data are recorded and analyzed by a computer. Systems may be temporary or continuous in nature.

Core Insulation Resistance

The core must be insulated from the windings and tank and connected to the tank through a single ground strap. The ground strap can be disconnected, and the insulation resistance of the system between the ground strap and ground can be measured. If a short remains, it is indicative of one or more additional grounds that would cause eddy current heating of the core and adjacent insulation and oil.

Frequency Response Analysis

Frequency response analysis testing can detect looseness in the winding and core. The test is performed off line. A transformer has both inductive and capacitive coupling that provide a characteristic frequency spectrum response when subjected to a low-voltage pulse or a low-voltage frequency sweep. This response will change when the core or winding shifts or is misshaped. The test is performed by comparing the current measurement to an initial measurement taken on the same or identical transformer. Figure 6-5 of EPRI report 1002913 [4] provides the difference in response for a loose winding to a tightly clamped winding.

Power Factor Testing

Power factor testing is an off-line test and is performed with voltages up to 10,000 Vac. When an insulator has deteriorated, the dielectric power losses through the insulation increase. The power factor is defined as the cosine of the voltage to the current phase angle. A perfect insulator has no losses, and the phase angle between the voltage and current would be 90° (cosine 90° = 0). In a real insulator, the power factor should be very low. There should be little or no change in power factor over time in a healthy insulation system.

Combustible Gas in Oil Monitoring Frequency

Most nuclear plants perform dissolved gas analysis once every six months on equipment operating normally. Some types of transformer degradation proceed slowly such that detection six months after it starts provides a reasonable lead time between detection and the point of failure. Others proceed rapidly once they begin such that six-month intervals would not be useful. Generally, when gas-in-oil analysis indicates that the transformer is operating in Condition 2, per Table 3-1, the frequency of sampling is increased to monthly. As the condition worsens, sampling is increase to weekly or even daily. However, if the condition is worsening rapidly, the delay in performing the laboratory tests (1–2 days) may be too long to be helpful.

One means of providing more timely results is to install a continuous gas-in-oil analyzer. The original on-line monitors detected hydrogen gas in the oil and alarmed when limits were exceeded. New systems can assess the full list of combustible gas in the oil and provide an immediate indication of problems without the delay that could occur with six-month interval samplings. The following section is provided to indicate the progression of failure that has occurred in a few instances to show the variability of times to failure from the time of detection.

Main Power Transformer Failure (INPO SER 3-06) [9] describes the progression from essentially normal gas levels through the point of failure for a main transformer. The trend from Condition 1 to Condition 2 progressed slowly and took over a year. Thereafter, the trend in gas concentration increased such that Condition 4 was exceeded in less than four months, and failure occurred shortly thereafter. Even though the utility had been preparing the spare transformer at the time of the failure, the rapid deterioration rate subsequent to July 2005 precluded having the full-sized spare ready. The short, three-month window, from the point at which Condition 3 was exceeded, precluded options other than the use of an existing spare transformer. Because a full-size transformer that was available was not in a serviceable condition, the plant had to return to service with a 90% capacity transformer and operate at reduced capacity until a full-size transformer could be placed in service. Figure 3-1 shows the rate of degradation by action levels and also shows the point at which the rate increased suddenly, approximately four months before failure.

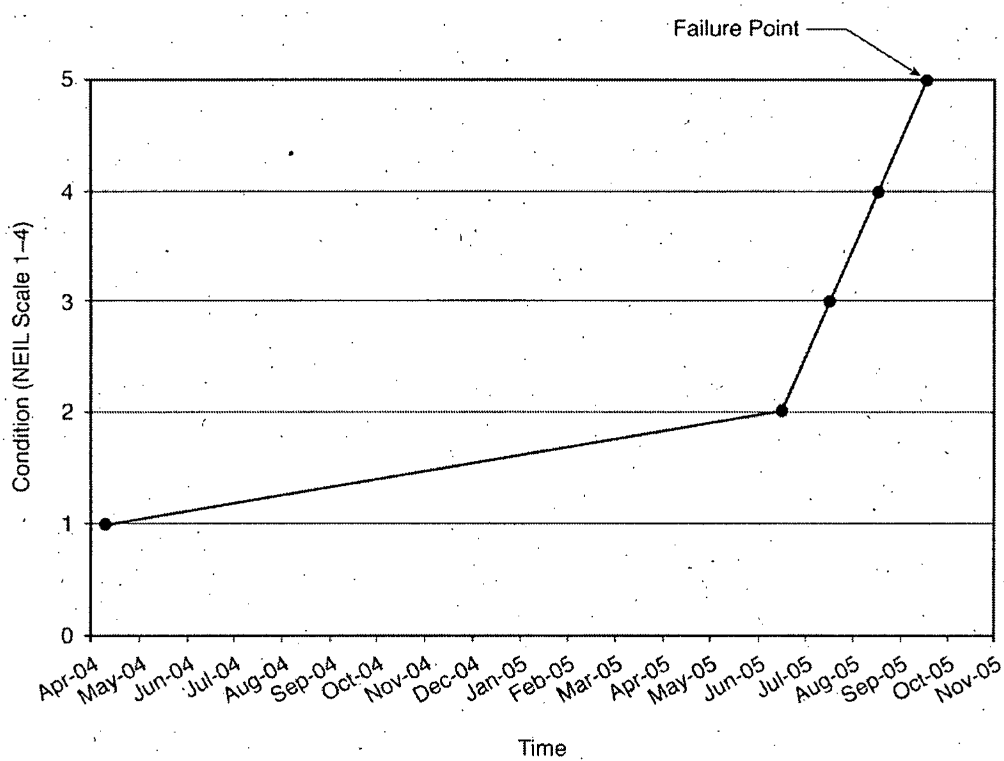

Figure 3-1
Progression Through Condition Levels from Time of Exceeding Condition Level 1 Through Failure of a Specific Main Unit Transformer

Main Power Transformer 2 Taken Off Line Due to Excessive Gassing (INPO OE 12812) [10] describes an event where the transformer gas in oil was monitored on a weekly basis. The unit was being operated while in Condition 2. Within a one-week period, the total gas in oil result shifted from 1267 to 2469 ppm. Periodic purging of the gas volume with nitrogen was begun in order to limit the amount of combustible gas in the transformer and to reduce the gas in oil results. About one month later, the off gas generation rate began climbing again, even though 24-hour purging with nitrogen was underway. Load on the main generator was decreased twice over the next few days, after which the unit was taken out of service to allow the transformer to be inspected and repaired. From the start of this event through having to remove the transformer from service was approximately nine weeks.

Supplement 2 to U2 Scram Due to Lightning Strike and Fire in Main Power Transformer (INPO OE 13116) [11] describes an event where no warning was observed when the transformer failed. In this failure, a design error caused undersized bus bars to be used that overheated and caused loosening of the bus bar support system. A through fault from the flashover of a transmission line off site caused the bus to move and create a phase-to-phase fault.

As shown by these examples, in some cases, there is no early warning. In such cases, the transformer has a sudden failure, or on-line monitors indicate a serious problem that requires immediate removal from service. In other cases, the lead time, as indicated by condition monitoring, between transition from an elevated level of concern to failure can be of intermediate length (weeks to months), giving reasonable time to start corrective measures. In nearly all cases, the lead times are shorter than the time necessary for the procurement of a new transformer. Generally, condition monitoring data allow plant operators to contact transformer experts and bring additional assessment tools into play. Often the monitoring results allow the operator to remove the transformer from service prior to a catastrophic failure. The results also allow operators to consider the risk of continuing to use the transformer.

4 LOGISTICS AFFECTING END OF USEFUL LIFE AND RECOVERY FROM FAILURE

Proactive replacement of an old transformer during a planned outage can occur more rapidly than replacement of a transformer that fails in service, even when a spare exists on site. The following sections provide an indication of the time to restoration to service after a significant failure or an adverse condition monitoring result indicates that removal of the transformer from service is prudent.

Logistics Issues

Two basic types of replacements are planned replacement and replacement upon in-service failure. There is a third condition in which a transformer fails while in service, but is repairable in place (for example, a condition such as a bushing failure that does not damage the internals of the transformer). Depending on the time to repair, such a failure may be repaired in place or the spare may be installed to shorten the outage time. The following sections describe issues associated with spares, replacement, and off-site repairs.

Spare Transformers

The three major logistic issues related to spare transformers are the existence of a spare transformer, the condition of the spare, and the location of the spare. The first issue is whether a spare transformer exists. If there is no spare, a search will be required to determine if a similar transformer exists that may be purchased and transported to the site or if a new transformer must be purchased and manufactured.

Assuming that a spare exists, the spare must be properly maintained, and its condition must be known. A spare that has not been properly receipt inspected and tested upon arrival at the site and maintained over the years is likely to be unacceptable for service. *Main Power Transformer Failure* [9] describes an attempt to use a spare transformer after the failure of a main unit transformer. The spare had had oil sampling performed, but had never had an internal inspection until the time of attempted use. This spare was found to have copper spatters and internal bus connection anomalies that could not be readily repaired. Accordingly, an undersized transformer had to be put in place, causing a reduction in plant output.

Location of Spare

Spare transformers may be located on or off site. Some utilities have a system spare for like transformers, which may be located at another station or substation. Transportation of large transformers is not a trivial issue. Even moving a transformer a few hundred yards requires the oil to be removed and a major rigging effort in order to move the transformer in place. Once the transformer is in place, it must be refilled with oil, and the oil and transformer must be treated to remove contaminants and moisture that entered during the transfer process.

If the transformer must be shipped from another site, a special underslung rail car or a Schnabel car may be required to allow the transformer to be moved through the height and width restrictions of the railroad rights of way. The availability of the special car and the planning with the railroads and the Department of Transportation may add to the period needed to ship the transformer. If the transformer must be moved by road, very special transporters with 16 or more axles may be necessary. Department of Transportation approval may be needed for moving the transformer by road.

Some plants may use river and ocean transportation via barge or a combination of barge and land transportation. Barge transportation also entails obtaining approvals. In addition, special cranes may be necessary to load and unload the barge.

A key issue is whether the railroad rights of way to the site remain in acceptable condition. The railroad rights of way originally used to ship equipment to the site may have deteriorated or have been removed from service such that moving large loads could be a problem.

Uprates and Spare Transformers

Uprates may have required the main transformer to be upgraded with respect to cooling or to have been replaced with a larger transformer. If so, the spare transformer should have been upgraded or replaced to preclude having to run the plant at a reduced output should an in-service failure occur.

Planned Replacement

Case 1. Replacement with a Staged Spare or New Transformer

In this scenario, a spare or new transformer is staged adjacent to the transformer to be replaced. The replacement transformer is filled with oil. The oil is filtered and moisture is removed.[1] The appropriate on-site tests are completed. During the plant outage, the old transformer will be moved from its location, and the replacement transformer will be carefully moved into place,

[1] Care must be taken during the initial operation of a transformer that has had its oil dried. Static charge buildup, especially in cool weather, can occur when oil is pumped through the winding, leading to flashovers of the transformer insulation. Cooling pumps should remain in automatic temperature control condition rather than be manually placed in the on position. See Section 4.6 of EPRI 1002913 [4].

connected, and an acceptance test must be performed. Table 3-1 lists the activities and an estimated period of one to two weeks to complete the installation. The period covers only installation. Much of the previous work involving the movement of the new or spare transformer to the new location and preparing it adjacent to the transformer to be replaced may take several weeks. In addition, if a new or spare transformer is being used that does not match the original transformer, many modification packages may have to be prepared. Also, modifications may be needed to mounting pads, leads, and instrumentation and control connections for the transformer.

Failure in Service – No Spare

Case 2. No Transformer Available

In this case, a transformer has failed, no spare is available, and a transformer suitable for the application cannot be identified. A new transformer must be purchased. If transformers of this type have not been purchased recently, it is very likely that the existing transformer specification will have to be upgraded to include current technical and test requirements. The procurement documents must be issued, and the transformer must be manufactured and subjected to acceptance tests at the manufacturer's site. The oil will have to be removed, and the transformer will have to be shipped by rail or ground using special vehicles (for example, Schnabel cars and 16- or more axle tractor trailers). Special permission is likely to be needed from the Department of Transportation in order to move the transformer through railroad rights of way or on highways. Once on site, the transformer must be moved to the final location, inspected for transportation damage, refilled with oil, have the oil processed, and subjected to acceptance tests. Table 4-1 lists the activities, and an estimated period of 100 weeks or more may be needed to complete them. Most plants will take any viable option other than this one, including installing an undersized transformer and operating at reduced output. In addition, unless the replacement transformer is identical in configuration to the original transformer, modifications to the connections, mounting, and cooling systems may be required in order to allow the transformer to be used.

Case 3. Transformer Is Available in the Market Place

In this scenario, a transformer is available in the market place that is known to be in serviceable condition. The transformer must be emptied of oil, shipped to the site, placed in its final location, inspected, and filled with oil; the oil has to be processed; and the transformer must be subjected to acceptance tests. Table 4-1 lists the activities and states that an estimated five or six weeks may be necessary to complete them. Unless the replacement transformer is identical in configuration to the original transformer, modifications to the connections, mounting, and cooling systems may be required in order to allow the transformer to be used. Such modifications may significantly extend the required time to install and test the transformer.

Failure in Service – Spare Exists

Case 4. Spare Available But Condition Unknown

In this case, the two possibilities that exist are that the spare is unfit for service or through testing and processing of oil and any other maintenance activity, it is ascertained that the transformer can be made ready for service. In the first instance, a different transformer must be located or manufactured. The result is the same as in Case 2 or 3 with one to two additional weeks that will be lost due to the need to evaluate the unfit spare.

In the second instance, the spare is found to be acceptable. Table 4-1 lists the activities and states that an estimated time of four to seven weeks may be necessary to complete them if the spare is off site. Two and a half to four weeks may be necessary to complete the activities if the spare is on site.

Case 5. Spare Exists and Is Known to Be in Satisfactory Condition

In this case, the spare transformer has been maintained and tested to ensure that its acceptability is fully understood. The spare may be located off site and would require the removal of the oil, transportation to the site, inspection, refilling, and processing of the oil. Table 4-1 states that it may take three to six weeks to complete these activities. If the spare is on site, Table 4-1 lists that an estimated two and a half to five weeks may be necessary for the completion of the activities. The spare transformer may not be identical to the original. In this case, additional time is likely to be needed in order to implement modifications to allow the spare to be used.

The lead times for Cases 2, 3, and 4 may be partially offset by beginning preparation activities at the onset of adverse condition monitoring results for the in-service transformer. Evaluating the condition of the spare transformer, preparing work plans, and other activities can reduce outage time should the transformer need to be replaced or if it fails in service. While Table 4-1 lists activities associated with replacement, additional time may be necessary to perform cleanup should the in-service transformer fail catastrophically. Tank rupture and fire are not unusual in such cases.

Table 4-1
Transformer Replacement Logistics

Case	Condition	Procurement	Manufacture	Shipping	Site Preparation and Testing	Total Duration
1	No failure: Fully prepared transformer staged adjacent to the transformer to be replaced. Oil in tank and processed.	N/A	N/A	N/A	Remove old transformer, shift new transformer in place, perform tests: one to two weeks.	One to two weeks Note: If three single-phase transformers are being installed, the duration is likely to be four or more weeks.
2	Failure: No spare	No useful transformer available. Procure new unit. Update specification and issuance: one to two weeks.	Manufacture new transformer, perform specified manufacturing tests: 80+ weeks.	Remove oil. Obtain specialty rail car or over-the-road vehicle, identify route, obtain permissions for moving oversized load, and ship: one to three weeks.	Transfer transformer to final location, inspect, refill with oil, process oil, perform on-site tests, and place unit in service: two to three weeks.	84 to 88 weeks
3	Failure: No spare, but transformer available in market place (possibly undersized)	Useful transformer available (possibly undersized with respect to need) and known to be in good condition.	N/A	Proceed the same as Item 2: one to three weeks.	Transfer transformer to final location, inspect, refill with oil, process oil, perform on-site tests, and place unit in service: two to three weeks.	Five to six weeks

Table 4-1 (continued)
Transformer Replacement Logistics

Case	Condition	Procurement	Manufacture	Shipping	Site Preparation and Testing	Total Duration
4	Failure: Spare available but condition is unknown	N/A	N/A	Evaluate before shipping. If off site and acceptable, proceed with shipping per Case 2 or 3: Two to four weeks including pre-shipping evaluation and testing. If on site, evaluate before moving the transformer to the final location. Remove oil, and move to final location: a few days to one week. If unacceptable, proceed with the best option of Case 2 or 3 with one to two weeks added to the schedule.	If acceptable, proceed the same as Case 1 or 2: Two to three weeks.	If acceptable and off site: Four to seven weeks If acceptable and on site: Two and a half to four weeks (see Note 1) If not acceptable: Case 1 or 2 with one to two weeks additional time
5	Failure: Spare known to be in service-ready condition	N/A	N/A	If off site, proceed the same as Item 1: one to three weeks. If on site, remove oil, and relocate to final position: A few days to two weeks.	Transfer transformer to final location, inspect, refill with oil, process oil, perform on-site tests, and place unit in service: Two to three weeks.	If off site: Three to six weeks If on site: Two and a half to five weeks (see Note 1)

Note 1: Some plants have a spare phase adjacent to the associated transformer in a ready-to-use condition. If one of the phases fails, the wiring and bus work to the phases are reconfigured to take the failed phase out of service and place the spare in service. This reconfiguration takes approximately two days.

5 CONCLUSIONS

Table 1-1 indicates that the useful life of a large, oil-filled transformer is between 30 and 40 years with insulation or bus supports being the most likely to fail due to age. For the insulation, thermal aging of the paper insulation is the likely cause of failure. The life of the insulation can be shortened further by ingress of moisture or elevated operating temperatures. Internal bus supports, especially for transformers from the early 1970s, may also cause failure, especially if the transformers have been exposed to numerous through faults[2].

Having a spare transformer is a business decision on the part of a plant owner. However, a spare that has not been maintained and tested to ensure its readiness may be unfit for service and may be the equivalent of having no spare. If the spare is located off site, the availability of rail or road rights of way and special vehicles must be considered. The condition of the rights of way is also a consideration if a transformer must be shipped off site for repair or if a new transformer is purchased.

Replacement of an aging transformer may be necessary if condition monitoring results indicate the onset of deterioration. Proactive replacement can preclude catastrophic failure that could lead to environmental cleanup problems if the transformer tank fails. Catastrophic failure often leads to a transformer fire. Given adverse condition monitoring indications, the removal of a transformer from service prior to failure may allow for repair or refurbishment of the transformer and may shorten the unit's return-to-service time than if a catastrophic failure had occurred.

In the replace-before-failure scenario and in a proactive replacement scenario, the replacement transformer can be staged adjacent to the transformer to be replaced. Most preservice inspection, oil processing, and testing can be performed prior to a plant outage so that a transformer can be replaced in the shortest period possible.

The previous information has been provided in order to allow the reader to determine if long-term or contingency planning is desirable for large transformers and to help identify possible outage durations that could be expected and logistics problems that can occur. The choice to plan and the type of planning to employ are left to the reader. EPRI reports TR-106109 [3] and 1007422 [1] provide the information and methodology for LCM assessment. EPRI report 1003455 [2] provides an economic assessment tool that may be used to prepare cost assessments of different alternatives.

---

[2] A through fault is a fault external to the transformer that causes very high currents to flow through the transformer windings and causes high magnetic forces on the internal components of the transformer.

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A
QUESTIONS TO CONSIDER

The following questions can be used to determine the need for developing a long-term or contingency plan for a large, oil-filled transformer that is at or is approaching its expected end of life.

Expected Life

1. Has an evaluation of the expected life of the transformer been conducted?
2. Have industry and site-specific operating and maintenance experiences related to the transformer been assessed?
3. Has the transformer experienced failures that may have stressed long-lived transformer components?

Condition Monitoring and Assessment

1. What is the frequency of combustible gas in oil analysis? Are individual combustible gas limits assessed? (see Table 3-1) Are trends in the periodic results evaluated?
2. Has an on-line combustible gas analyzer been considered or installed?
3. Has an analysis of the rate of generation of combustible gases in oil been considered or used in assessing the condition of large transformers? (see Table 3-2)
4. Is the condition of on-line monitoring systems and alarms, such as temperature monitors, Buchholz relays, and gas analyzers, known to be acceptable?
5. Are operators and operations managers aware and trained in responding to condition monitoring results and transformer alarms?
6. Has the overall battery of predictive maintenance tests and assessments (for example, infrared thermography of transformer components, power factor testing of bushings, inspections for leaks, and a confirmation of function of cooling systems) been reviewed for adequacy with respect to a transformer approaching or at its expected end of life?

Logistics Questions

1. Does a spare transformer exist?
2. If a spare does not exist, has a contingency plan been developed to optimize the replacement time should a failure occur?

3. Are personnel (engineers and technicians) who understand transformer repair and replacement issues (such as transformer inspection and testing, oil treatment, and relay system connection and testing) available to the plant?
4. If a spare exists, is the spare known to be in satisfactory condition for service?
5. Is the spare on site? Is it stored away from the transformer it is meant to replace or located adjacent to it? (Some plants have the spare transformer mounted permanently such that reconfiguration of the leads allow the spare to be put in service in a matter of days.)
6. If stored away from the transformer that the spare is meant to replace, are the logistics understood for moving the spare into position and putting it in service?
7. If the spare is located off site, are the transportation logistics, such as availability of special rail cars or trucks, condition of rights of way, and special permissions from the Department of Transportation, understood?
8. If the spare is a common system or industry spare, are modifications to the transformer, foundation and mountings, bushings, and so on necessary to allow use?

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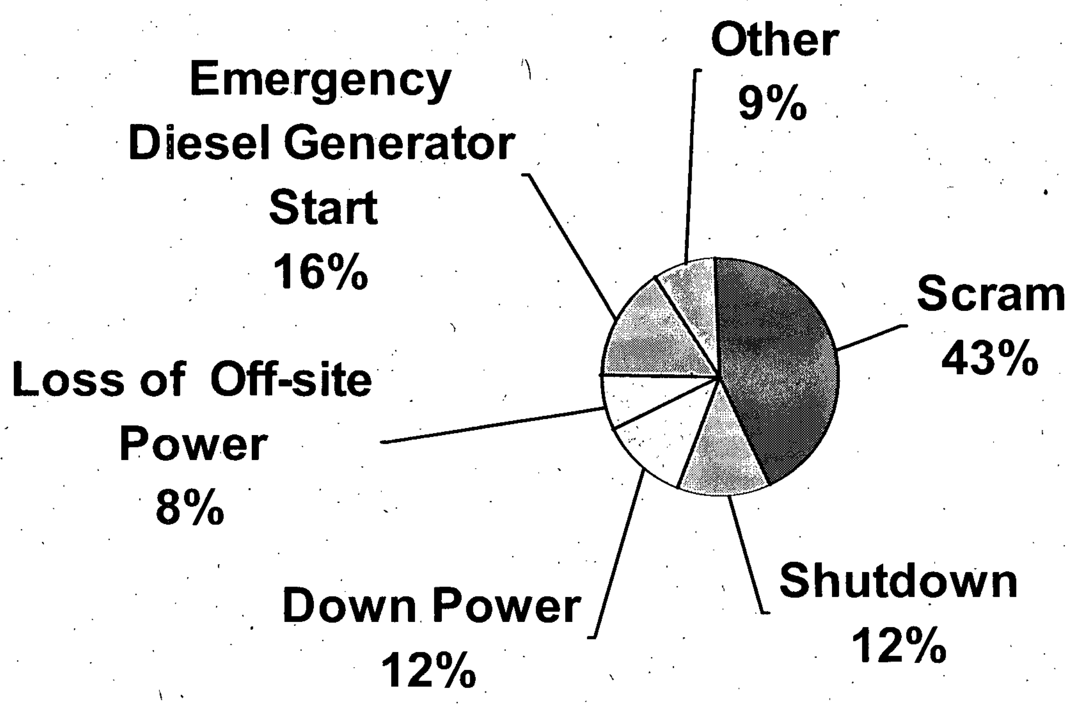
EXHIBIT 7

Life Cycle Management Planning Sourcebooks

Volume 4: Large Power Transformers

Technical Report



Consequences of Main Transformer Events

Life Cycle Management Planning Sourcebooks

Volume 4: Large Power Transformers

1007422

Final Report, March 2003

EPRI Project Manager
G. Sliter

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REPORT SUMMARY

EPRI is producing a series of "Life Cycle Management Planning Sourcebooks," each containing a compilation of industry experience information and data on aging degradation and historical performance for a specific type of system, structure, or component (SSC). This sourcebook provides information and guidance for implementing cost-effective life cycle management (LCM) planning for large transformers.

Background

As explained in the *LCM Sourcebook Overview Report* (1003058), the industry cost for producing LCM plans for the many important SSCs in operating plants can be reduced if LCM planners have an LCM sourcebook of generic industry performance data for each SSC they address. The general objective of EPRI's LCM sourcebook effort is to provide system engineers with generic information, data, and guidance they can use to generate long-term equipment reliability plans for plant-specific SSCs (aging and obsolescence management plans optimized in terms of plant performance and financial risk). The equipment reliability plan or "LCM plan" for a plant SSC combines industry experience and plant-specific performance data to provide an optimum maintenance plan, schedule, and cost profile throughout the plant's remaining operating life.

Objective

To provide plant engineers (or their expert consultants) with a compilation of the generic information, data, and guidance typically needed to produce a plant-specific LCM plan for large transformers.

Approach

Experts in the maintenance and aging management of large transformer systems followed the LCM process developed in EPRI's *LCM Implementation Demonstration Project* (1000806). The scope of the physical system and of component types included in the study was defined. Information and data on historical industry performance of selected types of large transformers within this scope were compiled. EPRI LCM utility advisors reviewed the sourcebook prior to its publication.

Results

This sourcebook contains information on large transformers such as Generator Step-Up (GSU), Unit Auxiliary Transformer (UAT), and Startup Auxiliary or Reserve Auxiliary Transformers (RATs/SATs). It also contains information on transformer accessories and monitoring devices for transformer protection and performance. Information includes performance monitoring issues, component aging mechanisms, aging management maintenance activities, equipment upgrades, and replacements. Based on this information, alternative LCM plan strategy guidance has been developed, along with recommendations. The plan strategy guidance provides information for implementing cost-effective LCM planning for large transformers. The sourcebook includes an extensive list of references, many of which are EPRI reports related to the maintenance and reliability of large power transformers.

EPRI Perspective

Using this report as a starting point should enable the preparation of plant-specific plans for large transformers with substantially less effort and cost than if planners had to start from scratch. The sourcebook captures both industry experience and the expertise of the sourcebook authors. Using this sourcebook, plant engineers need only add plant-specific data and information to complete an economic evaluation and LCM plan for the plant's large transformers. EPRI plans to sponsor additional LCM sourcebooks for as many important SSC types as may be useful to operating plants (perhaps 30 to 40) and as are allowed by industry-wide resources. The process of using sourcebooks as an aid in preparing LCM plans will improve as the industry gains experience. EPRI welcomes constructive feedback from users and plans to incorporate lessons learned in future revisions of LCM sourcebooks.

Keywords

Life cycle management
Nuclear asset management
System reliability
Component reliability
Large transformer

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1 MANAGEMENT SUMMARY

This Life Cycle Management (LCM) Planning Sourcebook for large transformers will help guide plant engineers or expert consultants in preparing a life cycle management plan (long-term reliability plan) for large transformers at their plants. The generic information and guidance presented in this sourcebook is expected to help plant engineers focus on areas where there may be significant opportunities for cost-effective improvements. Use of the sourcebook will reduce the cost of preparing a plant-specific LCM plan by approximately a third compared to starting from scratch.

The sourcebook identifies component aging mechanisms together with the maintenance activities to manage them, as well as obsolescence issues and available management options. It provides hypothetical LCM plan alternatives to serve as starting points for plant-specific applications. Guidance consists mainly of generic industry-wide information and references on large transformers and their components. Guidance is provided on how to build alternative LCM plans that can be considered during long-term planning for the critical components. Depending on the level of detail desired for the plant-specific LCM plan, the generic data in this sourcebook may allow engineers to identify areas where significant cost-effective improvements or reduction in maintenance activity can be realized and where long term planning for emerging obsolescence issues can be developed.

Important reasons for covering large power transformers in a sourcebook are:

- High reliability of large transformers is important to economic plant operation.
- At some plants, inspection and maintenance of large power transformers is not given a high priority.
- Some of the large power transformers and their components may become obsolete in the near future, requiring replacement, substitution, or upgrades, particularly for plants contemplating license renewal or power uprate.
- Increased load on the main transformer due to power uprate and increased electrical loads on the auxiliary transformers have reduced transformer life.

Large transformer industry reliability issues addressed by this study are:

- Monitoring of the oil and insulation quality is paramount to preserving the life of a transformer.
- Although transformers are designed and built for 30 to 40 year service life, operating and maintenance practices can affect their service life span.

The potential alternative LCM plans considered include:

- Implementing diagnostic maintenance, which includes programs such as thermography, oil analysis, etc.
- Establishing/revising Preventive Maintenance (PM)/Predictive Maintenance (PdM) tasks and schedules.
- Establishing refurbishment program.
- Maintaining a spare in the same fashion as the operating transformers.
- Establishing other options for spare transformers on a pre-negotiated basis with vendors or other plants.

2 INTRODUCTION

2.1 Purpose of LCM Sourcebooks

As indicated in the Life Cycle Management (LCM) Sourcebook Overview Report [1], an LCM sourcebook is a compilation of generic information, data, and guidance an engineer typically needs to produce a plant-specific LCM plan for a System, Structure or Component (SSC). This sourcebook will enable plant engineers or outside experts to develop a plant-specific LCM plan for large transformers with substantially less effort than if they had to start from scratch. The engineer need only add plant-specific data and information to complete an economic evaluation and LCM plan for large transformers.

It must be recognized that not all generic information in a sourcebook applies to every plant. Some of the data can serve for comparison or benchmarking when preparing plant-specific LCM plans. Other data may show indicators or precursors to problems not yet experienced at a given plant. Therefore, caution and guidance is provided in the plant-specific guidance sections (Sections 5, 8, and 9 of the sourcebook) for the use and application of the generic information. These sections also contain useful tips and lessons-learned from the EPRI LCM Plant Implementation Demonstration Program [2].

2.2 Relationship of Sourcebook to LCM Process

The process steps for LCM planning are described in detail in the EPRI LCM Report [2]. The LCM planning flowchart (Figures 2-1a, b, c of this large transformer sourcebook) is essentially the same as Figure 1-1 of the LCM Sourcebook Overview Report [1]. The chart is segmented into the four elements of the LCM planning process: SSC categorization/selection, technical evaluation, economic evaluation, and implementation. Process step numbering has been maintained consistent with the LCM report.

2.3 Basis for Selection of the Large Transformers for LCM Sourcebook

An LCM Sourcebook for large transformers has been prepared because the component met the following important objectives of the SSC selection process:

- Applicability to both BWRs and PWRs
- Importance to safety risk and regulatory concern
- Importance to power production
- Subjected to significant degradation and obsolescence
- Have a history of chronic maintenance problems

Figure 2–1a
LCM Planning Flowchart – SSC Categorization and Selection

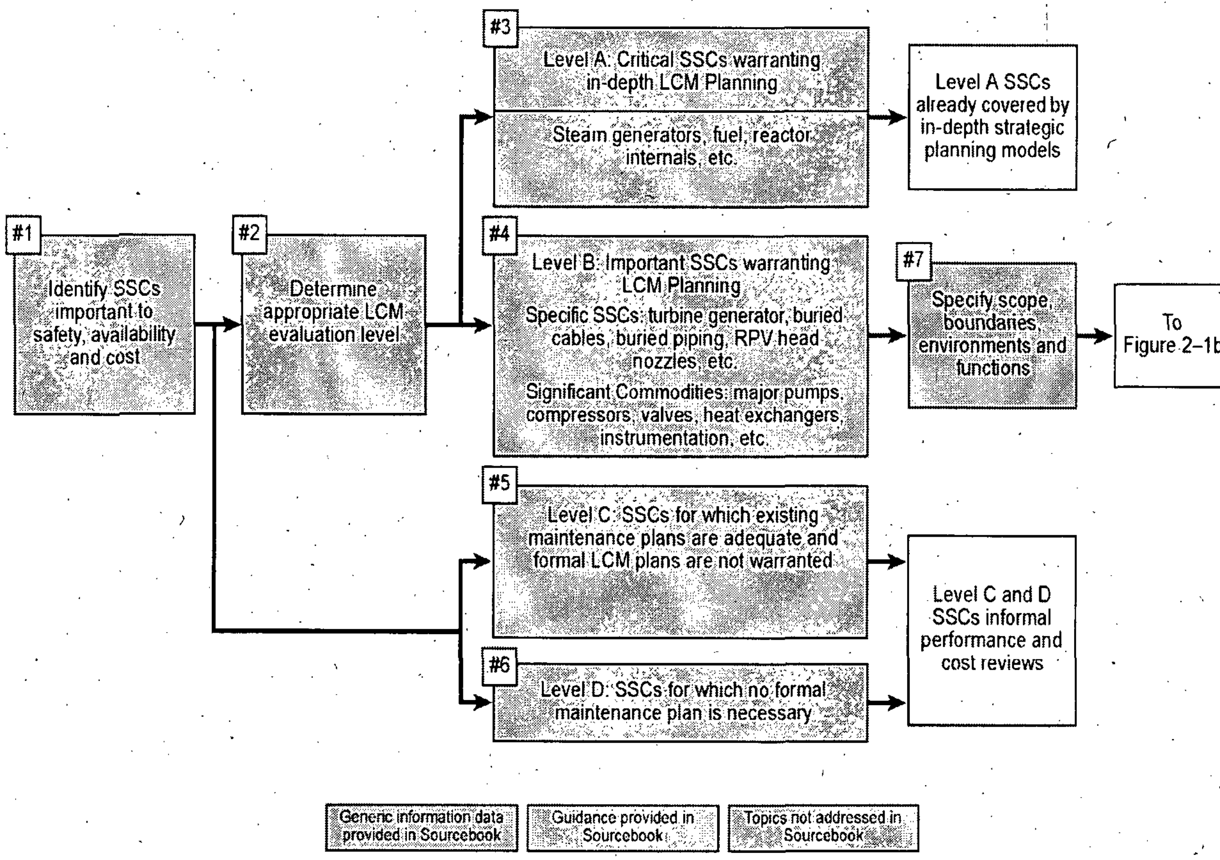

Figure 2-1a
LCM Planning Flowchart – SSC Categorization and Selection

Figure 2–1b
LCM Planning Flowchart – Technical and Economic Evaluation

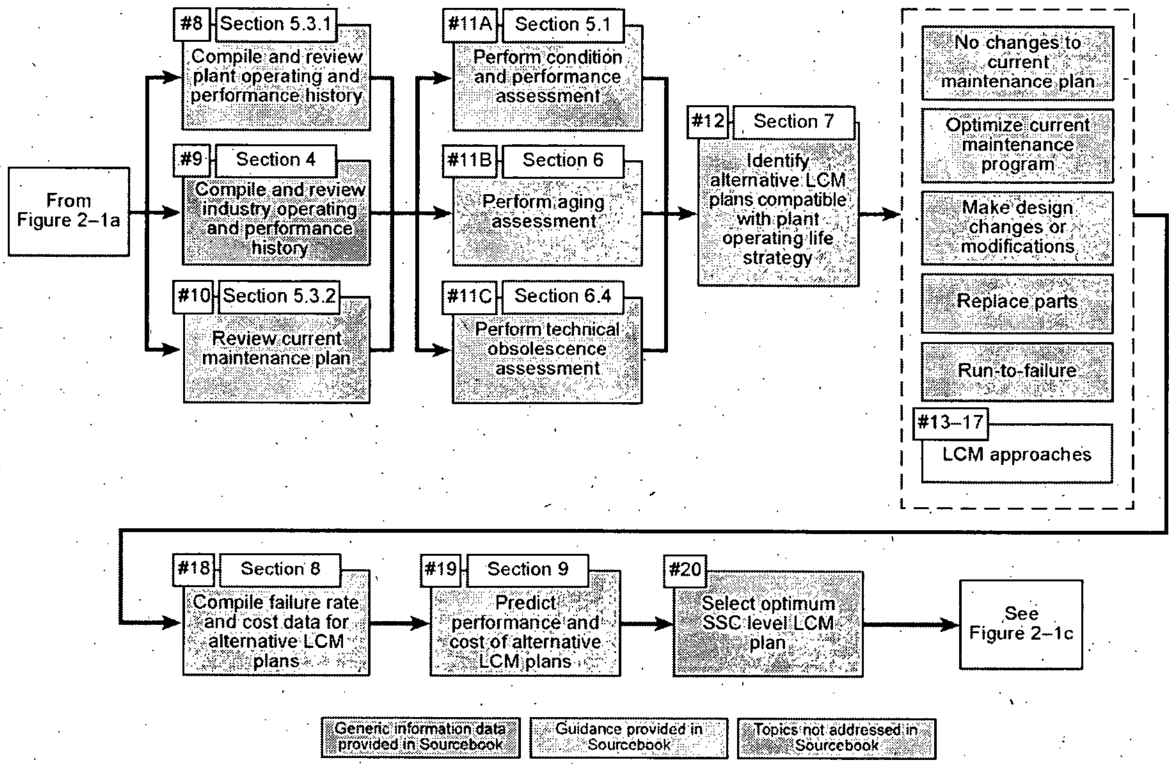

Figure 2-1b
LCM Planning Flowchart – Technical and Economic Evaluation

Figure 2–1c
LCM Planning Flowchart – Implementation

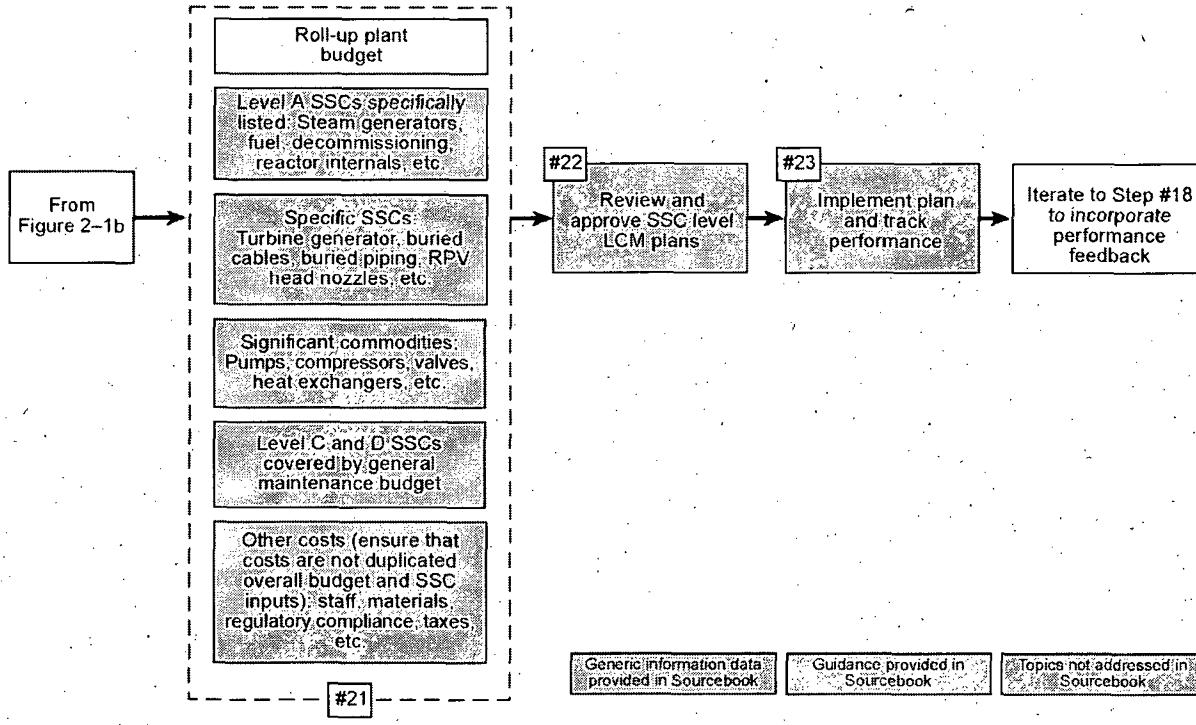

Figure 2-1c
LCM Planning Flowchart – Implementation

3

BASIC INFORMATION ON LARGE TRANSFORMERS

This section addresses step number 7 in Figure 2-1a. Large transformers are used in power plants to connect the main generator to the high-voltage (HV) transmission system. Large transformers are also used to connect the plant and off-site sources to the plant's distribution system for operation of auxiliary equipment at medium and low voltages. The large transformers of particular interest to the power plants range in size from 2.5 MVA to 1500 MVA with a voltage range of 4.16 kV to 765 kV and are typically installed outdoors. The characteristics of large transformers do not depend on whether the plant is a PWR or a BWR, but on the size of the transformer (i.e., MVA rating). Larger MVA range transformers are custom designed to meet the parameters such as voltages, short circuit currents, etc., specified by the plant requirements. This sourcebook will focus on Generator Step-Up (GSU) or Unit Transformers (UT), Unit Auxiliary Transformers (UAT), Startup Auxiliary Transformers (SAT), also called Reserve Auxiliary Transformers (RAT). EPRI's "Power Transformer Application and Maintenance Guide" [5], provides a list of the subject transformers in nuclear plants located in the US and Canada. The list indicates the manufacturers, ratings, and types.

3.1 Safety and Operational Significance

The GSU transformer is used to step-up plant generated voltage (18 to 26 kV) to the required grid voltage (115 to 765 kV). In contrast, the reserve and auxiliary transformers step-down the voltage to the desired plant system voltages (4.16 to 13 kV). The GSU transformers are non-safety-related but the loss of a main transformer could cause scrams, and/or transients, with the resulting loss of power production. The auxiliary transformers are typically non-safety-related, but they are "important to safety" as they supply power to the safety-related buses and also serve as an off-site power source for plant operation and shutdown. These transformers, along with the offsite power system, are designed to meet the nuclear plant general design criteria as stated in the FSAR and Technical Specifications. These transformers are the preferred source of power to supply the safety-related auxiliary buses under accident and post-accident conditions. Safety-related auxiliary buses are essential for safe shutdown or in preventing significant release of radioactive material to the environment. The safety-related buses are supported by diesel backup power; however, the loss of these transformers has major implications for plant safety and causes undesirable challenges to the plant safety systems.

The functions of large transformers are as follows:

- The GSU is used to connect the generator to the high voltage transmission system or to the grid. These are built as three-phase units in one tank or three single-phase units in separate tanks. Failure of the GSU will cause a plant trip.

- The UAT -- also called "normal station service transformer" -- is usually fed from the main generator leads and supplies power to the unit auxiliaries. The UATs supply power to the unit auxiliary equipment (4.16 or 13 kV) buses. Failure of a UAT causes the loss of one power source and may result in a plant trip or reduced power operation.
- The RAT or SAT is used to provide a second source of power for the plant auxiliary equipment from an off-site source. The RAT/SAT provides power to the station equipment when the generating unit is off-line, and serves as a backup power supply when on-line. The RAT/SAT feeds the plant auxiliary equipment through a segregated or non-segregated bus duct. The primary side of this transformer (off-site source) is high voltage in the range of 69 kV to 765 kV. Some plants have on-site auxiliary power supplies (gas-powered combustion turbine generators, auxiliary diesels, etc.), and therefore may not require an RAT or SAT.

Nuclear power plants are required by the NRC to have redundancy for their safety-related auxiliary power buses. UATs, RATs/SATs, and diesel generators feed the safety-related buses. Redundancy is provided to each safety-related bus by one or two UATs served by the generator and one or two SATs served from reserve or an alternate source. This system, with the desired breaker line-up, can bring power from another source to the plant distribution system. Another method is to provide redundancy by the use of a normal and/or maintenance (swing) bus. In this case, all loads are transferred to another bus fed from another source.

3.2 Large Transformer Functions

Large power transformers transmit bulk power for distribution and provide power for plant auxiliary loads. All large US-made transformers are designed, manufactured, and operated in accordance with IEEE/ANSI Standard C57.12.00, "General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers" [24]. The transformers considered in this sourcebook are large units, located outdoors, and typically liquid-cooled. Detailed information on large transformers can be found in textbooks and other publications such as the EPRI Power Plant Electrical Series, Volume 2, [22] "Power Transformers," and EPRI TR-1002913, "Power Transformer Application and Maintenance Guide" [5].

The generator is connected to the high voltage system through isophase bus ducts and the generator main transformer. The main transformer/GSU usually carries constant load. The primary winding of the GSU is connected by flexible links to the isophase bus duct that connects to the terminals of the generator.

The GSU normally requires no voltage regulating winding since the field of the generator regulates the voltage. The secondary winding of the GSU is high voltage and requires large internal clearances, which means the transformer tank is large. On large generator MVA output, some utilities choose multiple, single-phase transformers or two half-MVA capacity three-phase transformers.

The UAT is tapped off the isophase bus duct to feed the plant auxiliary equipment through a segregated or non-segregated bus duct. The UAT load may vary during startup and shutdown switching operations. The UAT primary and secondary voltages are medium range and the transformer tank is normally smaller with small internal clearances.

A second power supply for plant auxiliary equipment is provided from the preferred power supply (off-site source) though the RAT or SAT. The RAT/SAT provides power to the station equipment when the generating unit is off-line and serves as a backup power supply when the unit is on-line. It feeds the plant auxiliary equipment through a segregated or non-segregated bus duct. The primary side of this transformer (off-site source) is high voltage and requires large internal clearances.

Figure 3-1 is a typical generating station one-line diagram that illustrates the use of large transformers.

3.3 System and Component Boundaries

This LCM sourcebook includes the GSU, RAT, SAT, UAT, and their components. The detail and depth of evaluation for the individual components are commensurate with their importance and reliability.

The following subsections discuss the individual components and their respective functions and importance.

3.3.1 Transformer Components

The principal parts of a transformer include:

- tank and oil preservation
- magnetic core
- windings
- insulation system
- insulating liquid
- accessories

3.3.1.1 Tank and Oil Preservation

The transformer case or tank that houses the core and coil provides mechanical protection for the core and coil assembly and contains transformer cooling oil. Gaskets made of neoprene, cork-nitrile, nitrile, or viton are used throughout the transformer to prevent leakage of oil from pumps, manways, and accessory devices.

<u>*Sealed-Tank System.*</u> The sealed-tank type has a space above the oil in the transformer tank, which is filled with an inert gas such as nitrogen under pressure. The gas pressure is such that it does not cause high differential pressure between the inside and outside of the tank. The transformer tank and other components are tightly sealed, thereby preventing moisture entering the tank. Transformers utilizing this type of oil preservation system are equipped with a pressure/vacuum bleeder to allow the nitrogen to be expelled if the internal pressure gets too high, and allows outside air to enter if the internal pressure gets too low, thereby protecting the main tank from possible damage.

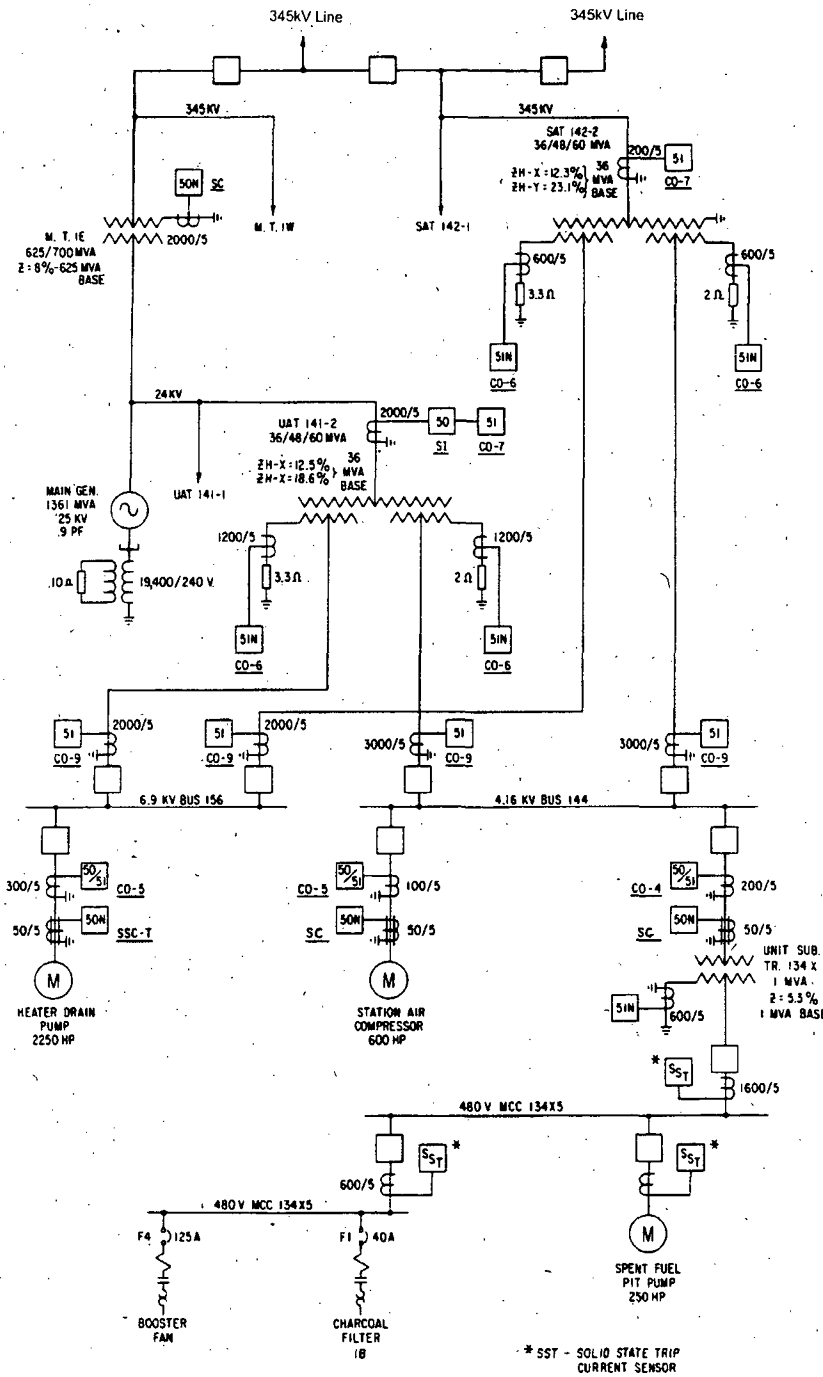

Figure 3-1
Typical Generating Station One-Line Diagram

<u>Inert-Gas-Pressure System</u>. The inert gas system uses a blanket of nitrogen to pressurize the void space above the oil volume to a pressure slightly greater than atmospheric. The nitrogen is supplied from storage bottles located near the transformer; a regulating valve maintains a slight positive pressure on the void space. During periods of expansion, another valve controls the venting of excess gas, thereby preventing over-pressurization. The regulating valves are calibrated to prevent simultaneous venting and charging of gas. Periodically, the gas bottle inventory is verified, and empty bottles are replaced or recharged.

<u>Sealed Conservator System</u>. In the sealed conservator, the entire volume of the tank is kept continually filled with fluid from a surge tank (conservator) mounted above the main tank. As the volume of the fluid decreases or increases, the surge is made up by or exhausted to the conservator tank. The void space (open to atmosphere) and fluid volume in the conservator are separated by a diaphragm (air cell or bladder) which prevents the contamination of the oil by moisture, gases, or other contaminants. The cycling of the air to the bladder may pass through an air dryer filled with desiccant. Oil level in the conservator tank is measured via a float-type level sensor; the main tank is always completely filled.

<u>Free-Breathing Conservator System</u>. This system is identical to the Sealed Conservator System except that there is no diaphragm or bladder. In this system, the surface of the oil in the conservator tank is exposed to the outside air. The cycling of the air in and out of the conservator passes through an air dryer filled with desiccant in order to keep moisture from entering the transformer. Transformers utilizing this system usually have a high oxygen content.

3.3.1.2 Magnetic Core

The core is that part of a transformer in which the alternating magnetic field flows. It provides a low-reluctance path for the flux linking primary and secondary coils. The core is made of a very high grade iron with a small percentage of silicon. The core is formed of thin sheets, and each side of each sheet is coated with an insulating material. The laminating and insulating thin sheets form a high resistance path to the eddy-current. This material prevents currents from circulating in the core with the resultant heat and loss of power.

Core laminations are properly secured by a clamping structure. The whole core assembly is clamped together by steel frames to hold the transformer windings together to withstand mechanical forces generated during normal operation or under fault conditions.

3.3.1.3 Windings

Transformer winding coils are designed and wound around the core according to the transformer ratio, i.e., the number of turns. An individual winding turn may consist of many copper strands that are insulated individually. The entire turn is usually wrapped in paper insulation. A turn usually consists of several individually insulated copper conductor strands. Some turns are constructed from continuously transposed conductor (CTC). The individual strands within the CTC occupy a different position in the turn as it is wound. This system is used to reduce leakage flux and thus has a higher short circuit strength. The windings are constructed by winding the turns over a winding cylinder, which is mounted on a winding mandrel.

Some of the basic types of transformer winding are disk, layer, pancake and helical. A disk winding consists of physically parallel winding sections, which are connected electrically in series. Each section of the winding contains one or more turns. Radial and axial spacers are placed between each section to provide insulation between sections and to allow oil to cool the copper conductors. Radial and axial spacers are also placed between turns of a helical winding for insulation and cooling purposes. Layer windings are composed of complete layers of turns spanning the length of the winding and separated by insulation and axial spacers for cooling. Pancake windings are used on shell-form transformers and are composed of individual rectangular washers stacked together to form the complete winding.

3.3.1.4 Insulation System

The most widely used winding insulation material is paper. When dried and impregnated with good quality oil, electrical grade paper has high dielectric strength. Besides winding insulation, insulating barriers are used between parts of the winding and between windings. As the paper ages, it becomes brittle. Other types of insulation, such as enamels, are used to insulate the copper strands that comprise a winding turn.

3.3.1.5 Insulating Liquid

The primary functions of the insulating oil are to insulate the primary from the secondary windings and ground, and to transfer the heat from the windings to external cooling equipment. The oil used in transformers is a highly refined mineral oil. Oil penetrates the paper insulation and fills the spaces between the core and coils, thus maintaining the properties of paper and other cellulose-based insulation material.

Transformer oil will maintain its maximum dielectric properties if the water content is kept low (the dielectric properties break down with increased water content). Some quantity of water is locked in the transformer cellulose insulation. Although a new transformer has gone through the drying process, insulation such as paper, pressboard, or other material is not water-free. When a new transformer is placed in-service, some of this water comes out of the insulation and mixes with the oil. In addition, moisture may be present in newly refined oil. External moisture from the atmosphere is another source of water.

Failures are minimal if oil and paper are kept dry, the oxygen content is nominal, and the hot-spot temperatures are not above the nameplate ratings.

Particle contamination also reduces the dielectric properties of transformer oil. Additives such as oxidation inhibitors and anti-sludging additives are used in the oil to improve its long-term characteristics

3.3.1.6 Transformer Accessories

Major accessories can contribute to transformer failures if not properly monitored and maintained. Examples of failed accessories that can contribute to transformer failures are bushings, load tap changers, and sudden pressure relays.

<u>Oil Level Indicator.</u> The oil level indicator is used to indicate the level of the insulating oil in liquid-immersed transformers. A common design of indicator uses a pivoted float arm located in the tank and magnetically coupled to a shaft and pointer arrangement outside of the tank, thereby allowing a completely sealed interface. When the position of the float changes, the magnetic coupling is rotated which moves the pointer a proportionate amount. The indicator also includes alarm switches for monitoring functions.

<u>Oil Temperature Indicator.</u> The oil temperature indicator consists of a temperature sensing bulb, indicating device, and a switch. The switch can be used to control fans, pumps, annunciator circuits. The indicator has switches for automatic control of one or two stages of cooling fans and an alarm switch.

<u>Winding Temperature Indicator.</u> For the most common type of winding temperature indicators, a simulated winding temperature is obtained by adding to the top oil temperature a temperature increment that results from the heat produced by a current proportional to the load current flowing through a heating element. Earlier versions of these devices used a physical resistance, located in a well near the top of the tank, to create the additional heat, but new types can do this through software. Electronic devices are also available and provide high accuracy.

<u>Gas Detector Relay.</u> A gas detector relay is used on transformers with a conservator tank. The relay is mounted on top of the transformer and is connected to a gas accumulator with tubing. The gas accumulator is under the top cover of the transformer. Under normal conditions, the gas accumulator is filled with oil. During abnormal conditions in the transformer tank, gases are generated from the deterioration of insulation or decomposition of oil around hot spots. Gases rise to the gas accumulator and the gas relay. If a significant amount of gas is generated, an alarm will be actuated. Another type of gas relay is known as the "Bucholtz relay," and is mounted in the pipe connection between the main tank and the conservator. Accumulations of gas in this relay will signal an alarm or trip the transformer.

<u>Pressure Relief Valve.</u> The tank design pressure (approximately 10 psig) is not sufficient to withstand pressures resulting from large internal faults and therefore, the pressure relief valve is used to relieve the pressure from the tank.

<u>Sudden Pressure Relay (Rapid Pressure Rise Relay).</u> The sudden pressure or fault pressure relay detects sudden pressure transients produced within the transformer tank during operation. If the internal pressure exceeds the safe limits, the relay will activate the tripping scheme to de-energize the transformer.

The sudden pressure relays are usually temperature compensated to allow relatively stable pressurization rate detection in the design ambient temperature range. Sudden pressure relays experience spurious actuations due to age (switch, spring, and diaphragm), vibration, installation error. Such spurious activity can be prevented by periodic functional tests and/or replacement.

<u>Deluge/Fire Protection.</u> Large power transformers can fail from either an internal or external electrical fault that results in over pressure of the tank. In cases where an internal pressure is rapid, the pressure relief device may not be adequate to prevent tank failure. Tank failure may release substantial quantities of insulating liquid and may initiate a fire.

NFPA 70, National Electric Code and NFPA 850, Fire Protection for Fossil Fueled Steam Electric Generating Plants, specify the type of protection required for oil-filled outdoor transformers. Protection includes the following:

- Separation
- Fire Barriers
- Detection and a water spray system
- Containment

<u>Nitrogen Regulation System</u>. The nitrogen regulation system is used to maintain positive pressure of nitrogen gas in the tank from an external gas cylinder. It prevents the oil from coming into direct contact with the surrounding atmosphere.

The gas regulation system consists of the gas cylinder, high and low pressure valves, by-pass valve, pressure bleeder, hoses, alarm contacts and gauges. An alarm is activated when the pressure in the external cylinder drops below 300 psi to warn personnel that a new gas cylinder is needed.

<u>Fans and Radiators</u>. For oil filled transformers, fans and radiators are mounted at various locations around the transformer for cooling. The fans are usually mounted on the radiators. The fans, motors, cables and conduit boxes are of weatherproof design and are suitable for outdoor use. Radiators that are difficult to clean are replaced with coolers having different design fins that do not clog easily and are easier to clean.

<u>Oil Pumps.</u> The oil pump circulates oil from the transformer tank through the oil coolers. The pump is controlled by the winding temperature detector. Bearing failure may occur on the oil pumps and motors.

<u>Tap Changers</u>. Transformers are usually provided with a mechanical switching device to adjust the voltage ratio by means of adding or removing turns from the winding. The change is achieved either manually when the transformer is de-energized, or automatically at load.

<u>De-Energized Tap Changers (DETC).</u> DETCs employ manually-operated switching equipment that changes the turns ratio of the three phases simultaneously and by the same amount. In the case of single-phase transformers, each has its own manually-operated DETC switching device. The DETC switching device is located in the main tank along with the core and coils, and the operating handle is normally located externally on the side of the transformer tank.

The DETC can be operated only when the transformer is de-energized.

<u>Load Tap Changers (LTC).</u> An LTC provides the mechanism to change taps without interruption of the load current. They are often used in distribution substations, but are relatively uncommon in power plants. The LTC compartment is periodically drained and the mechanism is flushed and cleaned, contacts cleaned; and the mechanism adjusted and timed. Internal wiring is sometimes replaced if worn. All gaskets are replaced when the tank is filled with new oil.

Lightning Arresters Lightning arresters play a vital role in the protection of transformers against transient over-voltages resulting from lightning surges and system switching transients. An arrester consists of an air gap in series with a resister element. A common type of arrester in use is the valve type, which consists of one or more gaps in series with a dielectric element serving as a high resistance. Another type is the gapless metal oxide arrester, which consists of a varistor embedded in a ceramic insulator. In an overvoltage condition, the non-linear resistance of the metal oxide reduces and causes excessive voltage to be shunted to ground.

Bushings Bushings provide a means of connection between the internal windings and the external circuit and insulate the primary and secondary windings from the tank. For power transformer high voltage applications, capacitor-type oil filled bushings are standard equipment. A limited number of utilities replace all bushings if the transformer is more than 20 years old or if the power factor is high. Several utilities are replacing a certain type of bushing, which has a record of failures over the years.

Potential Transformers (PTs). Potential transformers are used in the isophase bus duct to reduce the bus voltage to a lower voltage for input to the metering and relaying protective scheme.

Current Transformers (CTs). Current transformers are used to reduce primary current to a proportionally lower value suitable for metering, monitoring and protective schemes.

Control Cabinet. The control cabinet is a weatherproof metal enclosure designed to house all auxiliary devices except those that must be located directly on the transformer. Auxiliary devices in the control cabinet include fuses, breakers, control devices (relays and starters), alarm relays, and associated terminals for wiring and testing..

The control cabinet also houses the AC auxiliary power for pumps and fans, and DC control power. The AC auxiliary power normally has two sources of power and an automatic throwover scheme in case the normal feed fails to allow the emergency source to close in after a momentary interruption.

3.4 Scope and Equipment Covered by the Sourcebook

Large transformers addressed in this sourcebook are the main and the auxiliary transformers. Most of the large transformers used at nuclear power plants were manufactured by Westinghouse, General Electric, McGraw Edison, and ABB. The size range addressed in this sourcebook is 2.5 to 1500 MVA at a high voltage range of 115 to 765 kV and a lower voltage of 4.16 to 13 kV. This sourcebook focuses on the following principal parts and associated accessories considered critical for the continued operation of a transformer.

- Transformer tank and oil preservation
- Magnetic core and windings
- Cooling systems (including, pumps, fans, piping and the associated valves and instrumentation)
- Insulation system

- Electrical connections, terminals
- Lightning arresters
- Taps and tap changers
- Local instrumentation and monitoring equipment
- Current and potential transformers
- Bushings and insulators
- Radiators
- Control panel

The following items, even though important to the function of the transformer, fall under specific plant programs or are considered commodity items and, therefore, are not included in the scope of this sourcebook:

- Transformer foundations
- Structural supports
- Electrical buses and cables
- Missile and fire barriers
- Fire protection
- Transformer protective relays (with the exception of sudden pressure relays)

4 INDUSTRY OPERATING EXPERIENCE AND PERFORMANCE HISTORY

This section addresses step number 9 in the LCM planning flowchart in Figure 2-1b. The information compiled in this section is to be used for a comparison or benchmarking to plant-specific conditions and operating experience. The qualitative data is intended as a checklist of potential conditions affecting plant-specific performance, while the quantitative failure data may provide insight into the potential for plant-specific enhancements and help identify where improvements can best be made.

For example, if the plant-specific component failure rates are much less than what the generic data indicates, one might conclude that the existing maintenance plan is effective and further improvements will be difficult to achieve. On the other hand, equipment performance may be attributed to an excessive maintenance program that would require an overall adjustment of the maintenance practices. Similarly, if the plant-specific component failure rates are substantially higher than the generic failure rates presented here, or if the contribution of large power transformers to lost power production significantly exceeds the generic (PWR or BWR specific) values, equipment replacement or major changes to maintenance practices may be required. Implied here is the notion that if the reliability performance of an SSC falls below a certain level, major maintenance efforts will be required to satisfy Maintenance Rule performance criteria. Ultimately, replacement may be considered if plant operation cannot be sustained.

It should be noted that this section addresses failure and failure data rather than repair practices and data. In general, repair times will be available from plant records and will depend on plant-specific maintenance practices. The mean time to repair (MTTR) will have an impact on the system availability.

4.1 Nuclear Industry Experience

A review of the available industry operating experience and events has been performed to extract the salient information and to present the data such that the plant engineer can assess the plant-specific performance of large transformers.

4.1.1 Qualitative Data

A comprehensive review and evaluation of large transformer problems can be found in SOER 02-3, "Large Power Transformer Reliability" [21]. This document shows that despite the industry's increased attention to transformer maintenance after SOER 90-1, "Ground Faults on AC Electrical Distribution Systems" [20] was issued, transformer events are on a general increase, as shown in Figure 4-1. After SOER 90-1 was issued, many nuclear plants in the early 1990s reviewed their AC distribution system, offsite system, and large power transformer maintenance programs. Documents such as SOER 90-1 emphasized the importance of good preventive maintenance programs and training.

Industry experts have identified the following as the major contributors to transformer problems:

- Because of downsizing measures, not enough experienced personnel are available at the stations to monitor or maintain equipment such as large transformers and therefore, some stations have become too dependent on vendors to perform their monitoring and maintenance.
- Many original equipment manufacturers are no longer in business; therefore, many stations are depending on others for service and technical support.
- Many stations have not retained the special technical knowledge related to high voltage equipment necessary to determine the condition of large power transformers and supporting equipment.

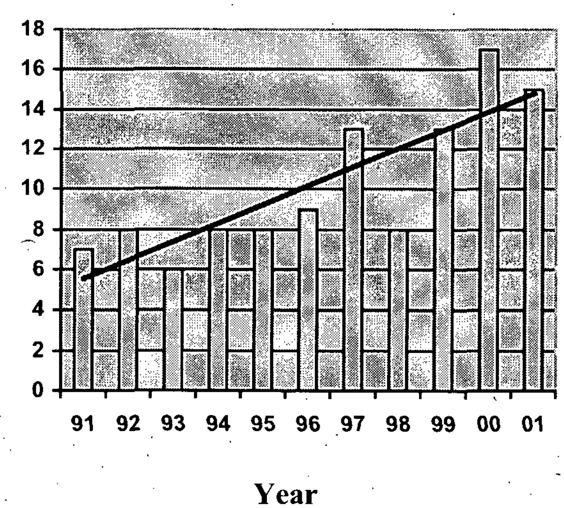

Figure 4-1
Number of Transformer Events Per Year

4.1.2 Quantitative Data

Quantitative failure data for large transformers and their accessories are available from a number of sources. Since 1996, there have been over 70 events associated with large main power transformers, according to SOER 02-3. Data from SOER 02-3 shown in Table 4.1 indicates the number of main power and auxiliary transformers involved in the event, the cause of the event, and the impact on the plant. There were over 30 reactor scrams, numerous plant shutdowns, several power reductions, and diesel challenges associated with the transformer events. Figures 4-2 and 4-3 graphically illustrate the magnitude of the transformer events and their causes.

Table 4-1
Transformer Events 1991 – 2001

	1991-1995	1996-2001	Failure Rate/ Year
Type of Transformer Involved in the Event			
Main station transformer	30	41	0.062063
Unit transformer	4	11	0.013112
Start up transformer	9	24	0.028846
Total Events:	43	76	0.104021
Type of Event that Occurred			
Transformer Trip	22	40	0.054196
Fire/Explosion	7	9	0.013986
Overheat	1	7	0.006993
Oil Leak	1	3	0.003497
Gas accumulation in oil	0	2	0.001748
Internal failure	7	1	0.006993
Others	2	2	0.003497
Most Likely Cause of the Event			
Bushing Failure	5	9	0.012238
Ground fault	3	8	0.009615
Insulation failure/short circuit	3	7	0.008741
External event	4	7	0.009615
Pressure relay failure	1	7	0.006993
Cooling system failure	1	6	0.006119
Maintenance	4	5	0.007867
Engineering	2	4	0.005245
Other	4	7	0.009615
Unknown	16	16	0.027972
Effect of the Event on the Plant			
Automatic Scram	25	25	0.043706
Manual Scram or shutdown	5	4	0.007867
Power reduction	1	7	0.006993

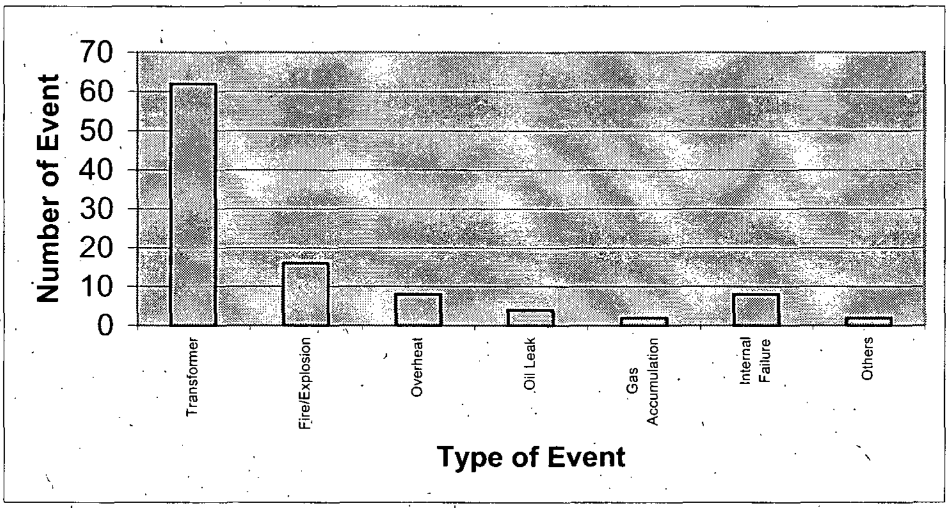

Figure 4-2
Transformer Events

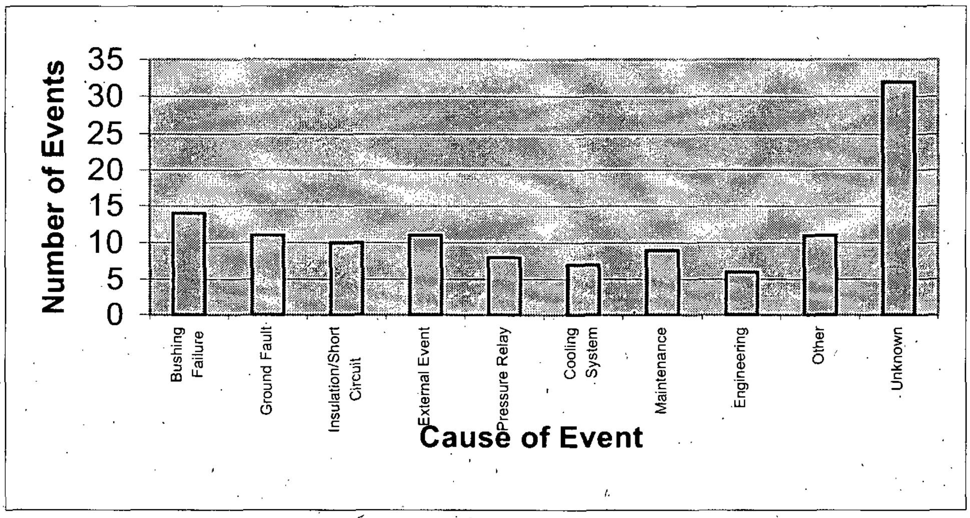

Figure 4-3
Causes of Transformer Events

4.1.2.1 Relative Magnitude of Large Transformer Failure Frequency

INPO SOER 02-3 provides industry benchmarking for large transformer failure data. The failure rate per year is tabulated in Table 4.2. This table was generated by using failures per year divided by the number of plants operating during that year (NUREG 1350, Table 7) [23].

Table 4-2
Failure Rates Calculated from EPIX (SOER 02-3) Data

Year	No. of Failures/Year From SOER 02-3	No. of Units Operating	Failure Rate (per unit per year)
1991	7	111	0.063
1992	8	110	0.073
1993	6	109	0.055
1994	8	109	0.135
1995	8	109	0.073
1996	11	110	0.100
1997	13	104	0.125
1998	14	104	0.135
1999	15	104	0.144
2000	17	104	0.163
2001	15	104	0.144

EPIX and NPRDS are collections of failure data for equipment and systems, as well as engineering and operational issues, taken from US INPO member plants and are available through the INPO website to INPO members. Besides the failure event data, the INPO database also contains reports, which describe the cause of the failure. The results of transformer events, as reported by SOER 02-3, are shown in Figure 4-4.

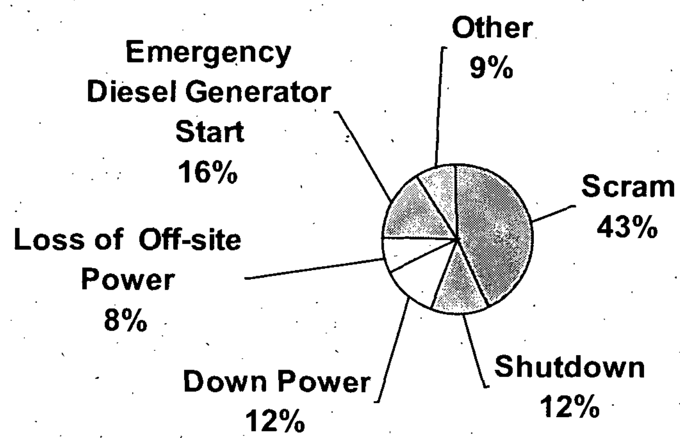

Figure 4-4
Results of Transformer Events

The failure rate trend per year up to 2001 was then projected (Figure 4-5) to predict the failure rate for the next 10 years (year 2011). If continued, this failure trend could increase from a current value of approximately 0.15 to a value of 0.2 by 2011. This factor can be used in Net Present Value (NPV) loss calculations to determine the impact on large transformer failures and economic impact.

The failure rates are calculated assuming the failures presented in Table 4.1 represent all failures that occur in a population of operating plants over a 10-year period, 1991-2001. The resulting failure rate per unit per year is presented in Table 4.2 and the failure rate is graphically show in Figure 4-5.

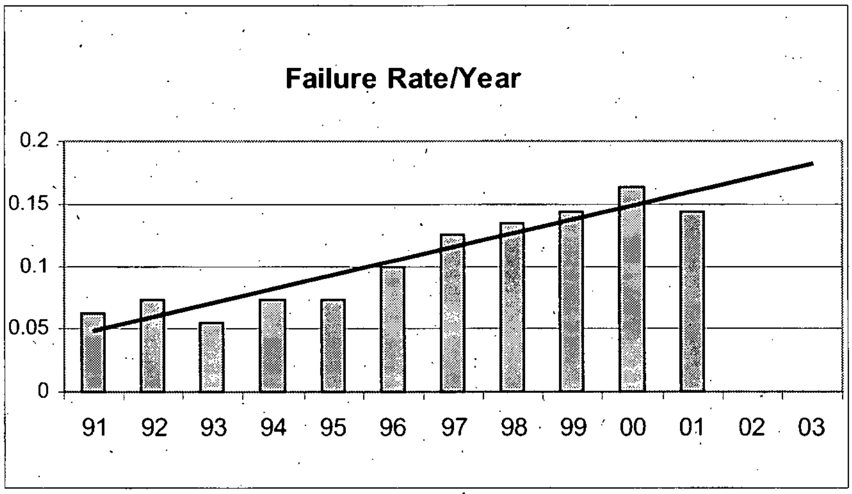

Figure 4-5
Transformer Failure Rate Per Plant and Per Year

4.1.3 Maintenance Rule

Maintenance Rule Section 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Plants," states the following requirements:

> "Each holder of a license to operate a nuclear power plant shall monitor the performance or condition of structures, systems, or components, against licensee-established goals, in a manner sufficient to provide reasonable assurance that such structures, systems, and components are capable of fulfilling their intended functions. Such goals shall be established commensurate with safety and, where practical, take into account industry-wide operating experience. When the performance or condition of a structure, system or component does not meet established goals, appropriate corrective action shall be taken."

Though large transformers are non-safety-related, they are included in the scope of the Maintenance Rule (10CFR50.65), which poses the following question: " Has failure of the non-safety-related SSCs caused a reactor scram or actuation of safety-related system at your plant or a plant of similar design?" As such, reliability and availability criteria are applied and data are gathered to monitor the equipment performance against these criteria. Accordingly, plant-specific data gathered for Maintenance Rule purposes should also be useful for LCM planning purposes. Additionally, plant-level performance addressing the number of plant trips, capacity loss, and the number of safety actuations may also apply. For most plants the main and auxiliary transformers are considered risk significant (they feature prominently in the station blackout analyses) and would, therefore, require system-specific availability or reliability performance monitoring under the Maintenance Rule.

The EPRI "SYSMON" software program [10] contains recommendations for performance monitoring for 37 systems, but large power transformers are not among the systems addressed.

4.1.4 EPRI PM Basis Templates

EPRI TR-106857-V38, "Preventive Maintenance Basis for Transformers (Station-Type, Oil-Immersed)" [3] provides a preventive maintenance (PM) template (Table 4.3) and a strategy for preventive maintenance to address degradation mechanisms. It also provides the tasks identified in these templates, including the subtasks discussed in the PM task descriptions, which are listed in PM Strategies Table 4.4. The expert group has identified the most common failure locations (mechanisms for transformer accessories and components) as shown below:

- Bushing faults
- Cooler problems, especially oil leaks and fan failures
- Oil leaks
- Oil quality problems
- Load tap changer problems, especially contact misalignment, coking, and oil leaks

Table 4-3
Transformers (Station-Type, Oil-Immersed)

			Critical				Non-Critical			
			High Duty Cycle Severe Service Condition	**High Duty Cycle Mild Service Condition**	**Low Duty Cycle Severe Service Condition**	**Low Duty Cycle Mild Service Condition**	**High Duty Cycle Severe Service Condition**	**High Duty Cycle Mild Service Condition**	**Low Duty Cycle Severe Service Condition**	**Low Duty Cycle Mild Service Condition**
	Critical	Yes	**X**	X	X	X				
		No					X	X	X	X
	Duty Cycle	High	**X**		X		X		X	
		Low		X		X		X		X
	Service	Severe	**X**	X			X	X		
PM Task	Condition	Mild			X	X			X	X
Calibration and Testing				4Y	5Y	4Y			5Y	5Y
Vibration/Acoustic/Sound Level				1Y	NR	1Y			NR	NR
Thermography				6M	1Y	6M			1Y	1Y
Dissolved Gas Analysis (DGA)				3M	1Y	6M			1Y	1Y
Oil Screening				1Y	1Y	1Y			1Y	1Y
Lightning Arrester Leakage Monitoring				AR	AR	AR			AR	AR
Motor Current Monitoring				1Y	NR	1Y			NR	NR
Tap Changer Maintenance (load only)				2Y	NR	4Y			NR	NR
Cooler Maintenance				2Y	5Y	4Y			5Y	5Y
Bushing Cleaning				AR	AR	AR			AR	AR
Maintenance Inspection				4Y	5Y	4Y			5Y	5Y
Engineering Walkdown				3M	3M	3M			3M	3M

Notes: The template does not apply to the run-to-failure components; non-critical here means not critical but important enough to require some PM tasks.

The shaded area indicates that no examples of station-type, oil-immersed transformers could be identified for these template conditions. If a utility were to identify a station-type, oil-immersed transformer that corresponded to a column in the shaded area it would be necessary to develop a PM program, probably similar to those stated. The shaded area does not mean run-to-failure.

Definitions:

- Critical-Yes: Functionally important, e.g., risk significant, required for power production, safety-related, or other regulatory requirements.
- Critical-No: Functionally not important, but economically important.
- Duty Cycle-High: Frequently cycled.
- Duty Cycle-Low: Continuous operation.
- Service Condition-High: High or excessive humidity, excessive temperatures (high or low) or temperature variations, excessive environmental conditions (e.g., salt, corrosive, airborne contaminants), loaded near to or above nameplate capacity, or operated in a backfeed mode.
- Service Condition-Mild: Absence of the above conditions.

Table 4-4
PM Tasks and Degradation Mechanisms (from EPRI TR-106857, V. 38)

		PM Task	Cal & Test	Vibration/ Acoustics/ Sound Level	Thermo-graphy	Dissolved Gas Analysis	Oil Screen	Lightning Arrester	Motor Current Monitor	Tap Changer Maint..	Cooler Maint..	Bushing Cleaning	Maint . Inspect.	Operator Rounds	Engineer Walkdown
		Interval	**4-5Y**	**NR-1Y**	**6M-1Y**	**3M-1Y**	**1Y**	**AR**	**NR-1Y**	**NR-4Y**	**2-5Y**	**AR**	**4-5Y**	**Shift**	**3M**
Failure Location	***Failure Timing***	***Degradation Mechanism***													
Transformer Oil (mineral)	Random on a scale of years	Loss of dielectric strength				X	X							X	
Windings	Random on a scale of years	Insulation breakdown	X	X	X	X	X								
Gaskets	Expected to be failure free for ~20 years, some random	Leakage												X	X
Tank	Random on a scale of about 5 years, if tank is contaminated	Corrosion													
Core	Expect to be failure free for 40 years, assuming oil is degassed as needed	Loose		X		X									
	Expect to be failure free for 40 years, assuming oil is degassed as needed	Loss of core ground	X												
	Expect to be failure free for 40 years, assuming oil is degassed as needed	Multiple core grounds				X									

Table 4-4 (continued)
PM Tasks and Degradation Mechanisms (from EPRI TR-106857, V. 38)

		PM Task	Cal & Test	Vibration/ Acoustics/ Sound Level	Thermo-graphy	Dissolved Gas Analysis	Oil Screen	Lightning Arrester	Motor Current Monitor	Tap Changer Maint.	Cooler Maint.	Bushing Cleaning	Maint Inspect.	Operator Rounds	Engineer Walkdown
		Interval	4-5Y	NR-1Y	6M-1Y	3M-1Y	1Y	AR	NR-1Y	NR-4Y	2-5Y	AR	4-5Y	Shift	3M
Core (cont.)	Random, on a scale of years	Shorted laminations	X			X									
Oil Filled Bushings	Expect to be error free for at least 15 years, some random	Leakage										X	X	X	X
	Expect to be failure free for 2-5 years, depending on severity of conditions	External contamination		X	X							X	X	X	X
	Random	Loss of BIL	X										X		
Solid Bushings	Random	Loss of BIL	X										X		
Lightning Arresters: (Metal Oxide Varistor type)	Random	Thermal runaway	X					X							
No-Load Tap Changer	Random	Misalignment	X			X									
	Random	Sheared gear pin, Contact Coking, etc.													
Load Tap Changer	Random	Misalignment, Contact Coking, etc.	X		X	X				X					
	Random	Damaged contacts	X	X	X	X				X					
	Expect to be failure free for 20 years	Leaks: gasket, piping, and valves				X				X				X	X
	Random, on a scale of years	Motor operator failure								X					X
Fins and Tube Coolers	Random	Airside fouling									X			X	X

Table 4-4 (continued)
PM Tasks and Degradation Mechanisms (from EPRI TR-106857, V. 38)

		PM Task	Cal & Test	Vibration/ Acoustics/ Sound Level	Thermo-graphy	Dissolved Gas Analysis	Oil Screen	Lightning Arrester	Motor Current Monitor	Tap Changer Maint.	Cooler Maint.	Bushing Cleaning	Maint Inspect.	Operator Rounds	Engineer Walkdown
		Interval	**4-5Y**	**NR-1Y**	**6M-1Y**	**3M-1Y**	**1Y**	**AR**	**NR-1Y**	**NR-4Y**	**2-5Y**	**AR**	**4-5Y**	**Shift**	**3M**
Fins and Tube Coolers (cont.)	Expect to be failure free for 15 to 40 years	Loss of heat transfer			X						X			X	
	Random, on a scale of 20 years	Leaks: tube to header									X			X	X
	Expect to be failure free for about 20 years, some random	Leaking gaskets									X			X	X
	Random, can be immediate	Dresser Coupling leaks									X			X	X
Radiators/ Oil Coolers	Random	Airside fouling									X			X	X
	Expect to be failure free for 40 years, some random			X		X								X	X
Fans and Motors	Expect to be failure free for 7 to 10 years, some random	Bearing wear		X	X				X		X				
	Expect to be failure free for 40 years, some random	Winding insulation failure													
	Expect to be failure free for 40 years, some random	Fan blade cracks									X				
	Expect to be failure free for 10-15 years	Motor power cable deterioration									X				

Table 4-4 (continued)
PM Tasks and Degradation Mechanisms (from EPRI TR-106857, V. 38)

		PM Task	Cal & Test	Vibration/ Acoustics/ Sound Level	Thermo- graphy	Dissolved Gas Analysis	Oil Screen	Lightning Arrester	Motor Current Monitor	Tap Changer Maint.	Cooler Maint.	Bushing Cleaning	Maint Inspect.	Operator Rounds	Engineer Walkdown
		Interval	**4-5Y**	**NR-1Y**	**6M-1Y**	**3M-1Y**	**1Y**	**AR**	**NR-1Y**	**NR-4Y**	**2-5Y**	**AR**	**4-5Y**	**Shift**	**3M**
Pump and Motor	Expect to be failure free for 40 years	Bearing wear		X					X						X
	Expect to be failure free for 40 years	Impeller and volute wear		X					X					X	X
Pump and Motor (cont.)	Expect to be failure free for 40 years, some random	Winding insulation failure													
	Expect to be failure free for 10-15 years	Motor power cable deterioration									X				
Valves	Expect to be failure free for 10 years	Stem leaks												X	X
	Random	Disk detachment													
	Random, on a scale of 10 years	Bound or struck													
	Expect to be failure free for 10 years	Air in-leakage				X								X	
Sudden Pressure Relay	Expect to be failure free for 40 years, some random	Mis-operation	X												
Buckholtz Gas Volume Relay	Random	Mis-operation	X												
Level Alarms	Random	Mis-operation	X												
Pressure Gauge	Expect to be failure free for 5-7 years	Drift	X												

Table 4-4 (continued)
PM Tasks and Degradation Mechanisms (from EPRI TR-106857, V. 38)

		PM Task	Cal & Test	Vibration/ Acoustics/ Sound Level	Thermo- graphy	Dissolved Gas Analysis	Oil Screen	Lightning Arrester	Motor Current Monitor	Tap Changer Maint.	Cooler Maint.	Bushing Cleaning	Maint Inspect.	Operator Rounds	Engineer Walkdown
		Interval	**4-5Y**	**NR-1Y**	**6M-1Y**	**3M-1Y**	**1Y**	**AR**	**NR-1Y**	**NR-4Y**	**2-5Y**	**AR**	**4-5Y**	**Shift**	**3M**
Temperature Gauge	Expect to be failure free for 4-6 years	Drift	X												
Conservator Tank	Expect to be failure free for 40 years	Bladder failure				X							X		
	Expect to be failure free for 40 years, some random leaks	Fittings and connection leaks											X	X	X
Desiccant	Expect to be failure free for 40 years	Outlet breather valve fails to seal				X									
	Expect to be failure free for a few years	Depletion												X	
Gas Blanket Systems	Expect to be failure free for 10 years	Regulator failure												X	X
	Random	Leaking: pipes, tubing, fittings, gaskets, and valves												X	X
Pressure Relief Device	Random	Improper Operation												X	X
Electrical Connections	Random	Loose			X								X		
Control Relay		See EPRI Report TR 10687, Vol. 30, Relays-Control													
Timing Relay		See EPRI Report TR 10687, Vol. 31, Relays-Timing													

Table 4-4 (continued)
PM Tasks and Degradation Mechanisms (from EPRI TR-106857, V. 38)

		PM Task	Cal & Test	Vibration/ Acoustics/ Sound Level	Thermo-graphy	Dissolved Gas Analysis	Oil Screen	Lightning Arrester	Motor Current Monitor	Tap Changer Maint.	Cooler Maint.	Bushing Cleaning	Maint Inspect.	Operator Rounds	Engineer Walkdown
		Interval	4-5Y	NR-1Y	6M-1Y	3M-1Y	1Y	AR	NR-1Y	NR-4Y	2-5Y	AR	4-5Y	Shift	3M
Motor Starters, Breakers, and Transfer Contactors: Wiring, Fuses, and Lights		See EPRI Report TR 106857, Vol. 8, Low Voltage Electric Motors (600V and below)													

4.1.5 Current PM Activities and Candidate PM Tasks

The EPRI PM templates provide an optimum set of maintenance activities for a select number of important components. However, a cost-effective maintenance program may use simple tests to determine if more extensive testing should be performed. Internal and external maintenance operations are then performed when the test results so indicate. Based on a review of the industry best practices, the recommended tests are indicated in "Recommended Maintenance Tests" described in EPRI report 1000031 "Guidelines for the Life Extension of Substations" [4] and are summarized in Table 4.5. Table 4.5 provides minimum inspection maintenance frequencies. Table 4.3 provides PM tasks for transformer accessories along with the recommended frequencies, depending on the duty cycle and service condition of the transformer.

Table 4-5
Maintenance Tests, Routine Maintenance, Inspections and Frequency

Maintenance Task	Recommended Minimum Maintenance Frequency
Condition Assessment Tests:	
Oil dielectric strength and moisture content	1 year
Oil interfacial tension and acidity	2 years
Dissolved gasses in oil	1 year
Winding insulation and bushing power factor	5 to 7 years
Infrared thermography	6 months to 1 year
Routine Maintenance and Inspections:	
External inspection	3 months
Bushing cleaning	Determined by visual inspection
Heat exchanger maintenance	1 to 2 years
Calibrate gauges and relays	5 years
Functional tests	5 years
Load tap changer	2 to 4 years

4.2 NRC Generic Communications and Other Reports

4.2.1 NRC Communications

A review of generic communications issued by the NRC identified the following documents to be significant for their impact on large transformers and on the plant.

Information Notice 2000-14: Non-Vital Bus Fault Leads to Fire and Loss of Offsite Power- Information Notice 2000-14 addresses the undetected damage from the failure of a bus duct, a passive component known for high reliability and often receives little preventive maintenance or attention. The phase-to-phase fault occurred in a 12 kV, non-Class 1E electrical bus duct from the unit auxiliary transformer to the switchgear that supplied power to the reactor coolant pump motors and the circulation water pump motors. The initial fault and the resultant arcing and smoke caused another fault in the 4 kV bus duct directly above the initial fault. An auxiliary transformer explosion in 1995, subsequent repairs, and inadequate fastener torques were the probable cause, resulting in a heated joint and leading to failure.

Information Notice 97-037: Main Transformer Fault With Ensuing Oil Spill Into Turbine Building addresses the main transformer low voltage bushing failure that caused an oil spill into the turbine building via the isolated bus duct. This notice presents a case in which a large amount of transformer insulating oil could bypass fire hazard control features, such as oil impoundment pits, and spill into the turbine building and other areas of a nuclear power plant.

Information Notice 82-053: This notice discusses the "Main Transformer Failures at the North Anna Nuclear Power Station," and describes seven main transformer failures, including one that resulted in a fire and one that caused extensive damage to the main generator.

4.2.2 Other Nuclear Industry Data

Select nuclear plant experience records are summarized here to identify the types of failures occurring with large power transformers.

SER 1-96, Transformer Explosion and Loss of Off-Site Power: On October 21, 1995, during a refueling outage, an explosion and fire occurred on one of the PWR unit auxiliary transformers. As a result, Unit 1 lost off-site power. During the restoration, a temporary grounding breaker located in one cubicle of the non-vital bus was accidentally left in place on the bus. When the feeder breaker from the auxiliary transformer was closed to energize the bus, a direct electrical path to ground was created causing a current surge that ruptured the transformer and initiated the explosion and fire.

SER 47-85, Loss of Off-Site Power: On August 16, 1985, at a BWR, a transformer fault and subsequent failures in the automatic transferring of loads resulted in a loss of off-site power to one unit. Due to a failed insulating board, a fault occurred on the secondary side of the transformer supplying Unit 1 loads, causing a short across the bus duct housing.

SER 52-85, Loss of AC Power and Feedwater Line Water Hammer: On November 11, 1985, at a PWR, a transformer trip led to a reactor trip and temporary loss of AC power.

SEN 128, Transformer Explosion and Loss of Off-Site Power: On October 21, 1995, at a PWR, an explosion and fire occurred on one of the Unit 1 auxiliary transformers. Investigations indicated that the auxiliary transformer was unintentionally grounded through a grounding breaker installed on an associated 12 kV bus.

OE14036 and Event Number: 374-020304-1- Main Power Transformer Insulating Oil Low Dielectric Value: On March 4, 2002, at a BWR, the results of a routine main power transformer dissolved gas oil analysis showed a dielectric value of 18 kV, which is below the Nuclear Equipment Insurance Limited (NEIL) lower limit of 26 kV. Three additional samples taken during the next five weeks showed dielectric values to be above the NEIL limit. The low values were ultimately attributed to particulates in the transformer oil after detailed evaluations eliminated sampling techniques and water as causes. A filtering system was subsequently installed to remove and analyze particulates.

OE11645, OE 11418, Fire in Unit 2 "B" Main Transformer: On September 22, 2000 at a BWR, "B" phase main power transformer (2B MPT) caught fire, which was limited to the top portions of the transformer.

OE13116, OE12778, OE12564, Event Number: 265-010802-1 Scram Due to Lightning Strike and Fire in Main Power Transformer: On August 2, 2001, at a BWR, a lightning strike on a transmission line two miles from the station resulted in a failure of the main power transformer and an automatic reactor scram. The resultant transformer fire was extinguished in approximately 30 minutes by actuation of the transformer's fire protection deluge system, the site's fire brigade, and an offsite fire department. The root causes of the transformer failure were design and construction errors that resulted in mechanical failure of the bus bar clamps. The bus bars and bus bar fiber bolting material were undersized. These conditions led to increased heating, bus bar motion, and stress on the clamps. Other factors included the vulnerability of the affected transmission line to lightning strikes, exposure of the transformer to a large number of electrical faults, and the failure to increase inspection and monitoring following these faults.

OE9613, Transformer Tap Changer Causes Diesel Generator Start: On December 22, 1998, at a PWR, during heat-up from a forced outage, a malfunction of the safeguards transformer automatic tap changer resulted in an undervoltage condition on plant 2400 VAC safety-related buses. The safeguards transformer is the normal power supply for the safety-related buses. A contactor, which causes the tap changer motor to move to lower positions, developed a three to four second delay in opening. This delay apparently resulted from the effects of cold weather acting on the contactors, which had been in service for nine years.

OE3289, Main Power Transformer: On March 23, 1989, at a PWR, the plant was taken out of service due to a high accumulation of combustible gases in Phase A of the main power transformer. The gassing had been attributed to the heating of "T" beam, low voltage short series leads, and corona shield.

OE12677, Event No. 272-010613-1, Event No. 272-010708-1, Power Reductions Due To The Loss of No. 1 Station Power Transformer: On June 13, 2001, the No.1 station power transformer (SPT) protective relay circuit actuated, tripping one section of the station 500 kV ring bus. Investigation of the event found that the No. 1 SPT phase-B regular differential relay target (DHR) actuated. The cause of the event was aging. Discussions with the original equipment manufacturers (OEM) established that there is no effective way to determine remaining service life, and no effective way to monitor surge arrester performance. The OEM recommendation for surge arresters is to implement a replacement program for those arresters 20 years of age or older. Long-term corrective action is to test each surge arrester periodically.

OE2150, RX SCRAM By Actuation Of Transformer Sudden Pressure Relay: On June 26, 1987, at a BWR, unit tripped during startup by actuation of a sudden pressure relay located on an auxiliary power transformer. The cause of sudden pressure relay actuation was the opening of a test (poppet) valve located on the relay.

OE9670, Transformer Fault due to Cracked Bus Bar Insulator on One Phase of Transformer's Secondary: On December 27 at a BWR, a cracked bus bar insulator on one phase of the transformer's secondary permitted electrical "tracking" to ground and consequently actuated overcurrent relays to automatically open the breaker to isolate the fault.

OE9082, Hot Connection Found In Unit Two Main Power Transformer: On June 2, 1998, at a BWR, a hot connection was found in the Unit 2 main power transformer local control cabinet while performing thermography.

OE2186, Auxiliary Power Transformer Failure: On June 6, 1986 at a PWR, a transformer failed and physical entry into the transformer and visual observations found debris of paper insulation and small amounts of copper particles. The cause of the failure was an overheating problem in the leads.

OE9246, Main Transformer Sudden Pressure Device Failure: On August 17, 1998, at a PWR, a main power transformer sudden pressure device actuated.

OE5127, Automatic Scram Due to Main Power Transformer Failure: On January 4, 1992, at a BWR, a sudden pressure relay actuated which caused both switchyard breakers to open and de-energize the three main power transformers.

SOER 02-3: From a review of SOER 02-3, which documents events from 1991 to 2001, sufficient information on the operating performance of large transformers is at hand to draw a reasonable conclusion on the performance of large transformers. The conclusions are presented in Sections 4.1.1 and 4.1.2 of this sourcebook.

4.3 Experience in Fossil Power Generation and Industrial Facilities

The subject transformers are also used in fossil plants and in other industries. This section discusses the experience with large power transformers in applications in other industries.

The failure data for transformers shown in Table 4.6 was extracted from the German Nuclear Utility Association represented by VGB [12] and European Reliability Data [13] for the relevant components. The former represents both BWR and PWR units and the latter represents PWR units.

Table 4-6
European Nuclear Power Plant Failure Data

COMPONENT	TYPE/SIZE	FAILURE RATE (1/HR of operation)	DATA SOURCE
Transformers	2.8-4.2 MVA	5.09 E-7	VGB
Main Transformer	24KV	2.2 E-6	EDF

Hartford Steam Boiler (HSB) analyzed the transformer failures that occurred in 1975, 1988, and 1998 [14] for various industries such as power plants, commercial buildings, manufacturing and metal processing facilities. The transformers analyzed included various applications. HSB concluded that the monetary losses arising from power transformer failures are the largest of the monetary losses arising from all transformer failures. Table 4.7 provides failure data for each failure cause as a percentage of the total failures. These failures are graphically shown in Figure 4-6.

Table 4-7
Analysis of Power Transformer Failures for 1975, 1988, and 1998

	1975	1988	1998
Lightning Surges	32.3%	30.2%	12.4%
Line Surges/External Short Circuit	13.6%	18.6%	21.5%
Poor Workmanship of Manufacture	10.6%	7.2%	2.9%
Deterioration of Insulation	10.4%	8.7%	13.0%
Overloading	7.7%	3.2%	2.4%
Moisture	7.2%	6.9%	6.3%
Inadequate Maintenance	6.6%	13.1%	11.3%
Sabotage, Malicious Mischief	2.6%	1.7%	0.0%
Loose Connections	2.1%	2.0%	6.0%
All Others	6.9%	8.4%	24.2%

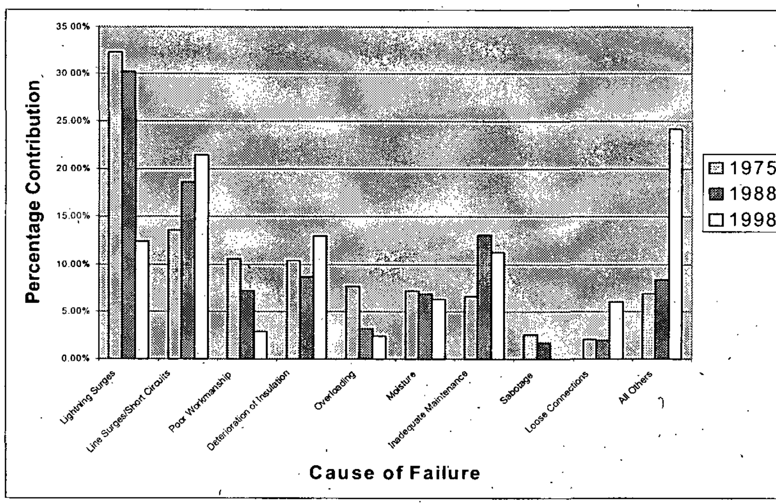

Figure 4-6
Number of Transformer Failures by Year

The HSB study concludes that line surges are the number one cause of all types of transformer failures. The second leading cause of failures is insulation deterioration. The average age of the transformers that failed due to insulation deterioration is 17.8 years, appreciably less than the expected life of 35 to 40 years. Inadequate maintenance is the next leading cause of transformer failures. This category included improper controls, loss of coolant, accumulation of oil and dirt, and corrosion. The study concluded that a planned maintenance, inspection and testing would significantly reduce the number of transformer failures and the unexpected interruption of power.

The Canadian Electricity Forum, Electricity Today, Issue 1, 2002 [15] published an article on transformer maintenance. The article includes dry type, oil-filled, and fluid-filled transformers. Causes of transformer failures are summarized in Table 4.8 and include failures for all three types of transformers. Although this data is for all three types of transformers large and small, it indicates that 73% of transformer failures are caused by insulation breakdown. The insulation breakdown is attributed to insulating liquid and/or winding coil failure.

Section 6.1 discusses applicable aging mechanisms and effects on transformer components.

Table 4-8
Transformer Component Failures

Transformer Part Failures	Percentage Contribution to Total Failures
High Voltage Windings*	48.00%
Low Voltage Windings*	23.00%
Bushings*	2.00%
Leads	6.00%
Tap Changers	0.00%
Gaskets	2.00%
Others	19.00%
Total	100.00%
* Components of Insulation System	

5 GUIDANCE FOR PLANT-SPECIFIC SSC CONDITION AND PERFORMANCE ASSESSMENT

This section addresses steps number 8, 10 and 11A in the LCM planning flow chart (Figure 2-1b) and provides guidance for the plant-specific LCM planning for large transformers. Also included in this section (Section 5.4) is a compilation and description of available and useful condition or performance monitoring programs.

- In Step 8, the plant-specific operating and performance history is compiled, as discussed in Section 5.1 below.
- Step 10 comprises a compilation and review of the plant-specific maintenance program for large transformers, leading to the establishment of a complete inventory of the current maintenance tasks and providing a basis of determining if enhancements or changes are desirable.
- In Step 11A, the intent is to characterize the present plant-specific physical condition and performance of the large transformers and the implementation of effective preventive maintenance procedures, diagnostics and component condition monitoring. The assessment of the maintenance tasks should pay close attention to whether and how the tasks address any deviations identified in this SSC performance assessment and the SSC condition review. The deviations may be positive in that plant-specific SSC performance and conditions are superior to the industry average, in which case unnecessary or too frequent PM may be performed, or the deviations may be negative, indicating a need or opportunity for improvement. Details of the condition and performance assessments are discussed in Section 5.3.

5.1 Compiling SSC Operating and Performance History

The current condition and age of large transformers have a major bearing on the LCM planning choices. In conjunction with performance reviews, a thorough assessment of the existing equipment is of paramount importance in making realistic decisions as to what maintenance options or strategies are feasible. Several elements are needed to complete the SSC condition review. These include reviewing records of the periodic visual inspections, reviewing diagnostic test and monitoring device data, test results which have been performed on the equipment, predictive technologies employed and results, modifications, work orders, and refurbishment data.

5.1.1 SSC Condition Reviews

The performance review of plant transformers is important in determining the options and includes:

- Assembling the maintenance history for transformers, particularly the corrective maintenance actions from the last five years (as a minimum). The maintenance history may also provide evidence of performance concerns or failures of other critical components, such as bushings, surge arresters, coolers, gaskets, fans, and load tap changers.
- Trending the failure rates to identify any specific type of transformer components that may exhibit unusual performance challenges or high failure incidents.
- Reviewing the inspection reports and condition monitoring reports to see if the current maintenance is effective in maintaining the equipment.
- Reviewing the Maintenance Rule (MR) performance parameters and trends, the system health reports, MR periodic assessments and the effectiveness of corrective actions implemented.
- Reviewing plant scrams and trip history to determine the events attributable to the large transformers and their components. For those events caused by the large power transformers, the lost power generation due to forced or unforced plant trips, scrams, extended outages, partial power operation or hot standby conditions is evaluated to determine the historical cost of the transformer failures. The results provide a basis for projecting future trends for LCM planning.
- A review of design changes and technology upgrades that have been instituted for replacement and equipment upgrades.
- Thermography, acoustics, oil analysis, regular walkdowns, and condition monitoring are some of the more effective tools for condition assessment and trending.

5.1.2 Periodic Visual Transformer Inspections

A condition assessment entails a visual inspection of the external condition of a transformer to look for abnormalities such as:

- Oil spills
- Paint deterioration, discoloration, peeling
- Evidence of corrosion, rust
- Staining from water or oil leaks
- Foundation crumbling, cracking (indicates abnormal thermal expansion)
- Loose and missing parts
- Deformation, vibration of tubing, coils, fans, conduit
- Audible corona discharge

- High sound level, humming
- Burning smell, ozone smell
- Damaged or chipped/cracked bushings, or lightning arresters
- High or low oil levels
- Loose grounding or terminal connections
- Other signs of abnormal conditions

5.1.2.1 Inspection Frequency

A periodic transformer inspection is an effective maintenance tool for locating situations and problems that are not indicated by sensors or other means. The problems are usually noted early so that corrective action can be taken before a more serious condition occurs. Transformers with a history of problems should be inspected frequently.

5.1.2.2 Typical Inspections

The following is a list of typical transformer inspection tasks and are applicable to most outdoor power transformers. It should be noted that the items inspected would depend on the equipment installed on the transformer and the record of performance in service. Those plants that perform inspections more frequently do not necessarily check all the following items during each inspection.

- Check transformer and auxiliaries such as tap changers and bushings for oil leaks. Record the location of the leak and the degree of leaking.
- Check operation of fans and pumps.
- Check to see that the proper cooling equipment is in operation. This procedure involves checking the oil temperature gauges to determine whether the cooling should be in operation.
- If the cooling equipment is in operation, note whether the appropriate fans and pumps are operating. Record any equipment not in operation. Check flow gauges on pumps.
- If the cooling equipment is not in operation, some utilities manually turn the equipment on to ensure that all fans and pumps are operative. Check flow gauges on pumps. Record any equipment not operating properly.
- Check for any abnormal noises, including pumps and load tap changers.
- Check the temperature of the load tap changer compartments with the infrared scanner for any abnormal temperature conditions.
- Check the temperature of the radiators with an infrared scanner. Investigate both high and low-temperature areas.
- Check all liquid level gauges for proper level including main tank, tap changer compartments, oil expansion tanks, and bushings.

- Check the bushings for chipped or broken sheds. At intervals, check the terminals for hot spots using the infrared scanner. Report any abnormal terminal temperatures immediately since bushing damage can result.
- Inspect all temperature devices. Record temperatures. Reset all maximum temperature indicators on the gauges.
- Check the pressure relief device to ensure that the device has not operated.
- Inspect all dehydrating breathers. Report any that indicate saturation with water.
- Check the nitrogen system including the bottle on transformers having nitrogen blanket oil preservation systems:
    - Report any increased usage of nitrogen.
    - Replace or have the bottle replaced if the pressure is below 300 psi.
- Inspect the paint and report any rust spots.
- Check all control devices such as gas collector and sudden pressure relays.

  Open the control cabinet door and inspect the devices:
    - Is the space heater operative?
    - Has water collected on the bottom of the cabinet?
    - Is the wiring in good condition?
    - Visually inspect the transformers and the auxiliaries. Report any unusual conditions.
- Inspect the lightning arresters.
- Check the heat exchangers:
    - Are the radiators and coolers clean?
    - Are the radiators and coolers warm at the bottom indicating that they are operating satisfactorily?
    - Does the airflow from the fans through the radiators and coolers appear to be normal? Is the air hotter than the surrounding air?
- Check the operations counter for the load tap changers. Report any usually high or low number of operations.

5.1.3 Review of Diagnostic Tests and Monitoring Devices

Review all available diagnostic tests and monitoring devices such as:

- Gas-in-oil-analysis
- Oil condition and dielectric strength
- Operational monitoring
- Original factory test report

- Insulation resistance and power factor
- Turns ratio
- Winding resistance
- Other monitoring and test results as described in Section 5.4, Condition Monitoring Technologies.

Gas-in-oil analysis is the primary method for determining the nature of problems within the transformer.

- High CO and CO2 accompanied by H2 without the presence of hydrocarbon gases such as CH4 (methane), C2H6 (ethane), and C2H4 (ethylene) are indicators of deterioration of paper caused by high oxygen and water contents in the system.
- High CO and CO2 with the presence of CH4, C2H6, and C2H4 are indications that there is overheating in an insulated part of the transformer.
- Significant amounts of CH4 with similar amounts of C2H4 with lesser amounts of C2H6 are indications of hot metal gases.
- Significant amounts of H2 with smaller amounts of other gases are an indication of partial discharges in the system. H2 can also be generated by free water in contact with the electrical steel of the core or by an overheated core.
- Acetylene (C2H2) is usually an indicator of arcing.

The water content of the oil and the paper can be estimated using the water content of the oil and the temperature of the oil when the sample was taken. The power factor and interfacial tension of the oil are indicators of contaminants in the system. The dielectric strength of the oil gives a general indication of the dielectric strength of the insulation system since oil is the weak link in the system.

In many cases, tests on oil samples taken while the transformer is in service provide the first clues of the internal condition of the transformer. Shown below is a list of "key gases" in relationship to the transformer insulation condition. Analysis of the key gases, depending on the level and quantity, i.e., parts per million (ppm), provides the internal transformer condition and gas activity.

- High concentration of carbon monoxide – thermal damage to cellulose
- High acetylene – internal arcing
- Carbon particles in the oil – probable internal electrical breakdown

If test results are available, the transformer condition assessment is made easier as shown below:

- Low oil dielectric strength – moisture or particle contamination
- Low insulation resistance – moisture contamination or damaged insulation
- Abnormal turns ratio – short turns in the windings

Table 5.1 [4] can be used to assess the overall condition of the transformer based on the results of the dissolved gas tests. Trending of the parameters based on the test results of the key gas concentration will provide the transformer condition and operational limits. Once it is determined that the concentration of certain gases is above normal, individual gas ratios can give further indication of the type of fault causing the high levels. Rogers ratios are a common tool for assisting with this determination.

Since all normally operating transformers will have some levels of the above-mentioned gases dissolved in oil, with the exception of acetylene, it is important to identify concentration levels for which the user should have concern. IEEE Std. C57.104, "Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers" [25] provides the guidance. Table 5.1 presents the key gas concentration levels and conditions that may require further action.

Table 5-1
Dissolved Gas Concentration

	Dissolved Key Gas Concentration Limits (ppm)							
Status See Notes	**H_2** Hydrogen	**CH_4** Methane	**C_2H_2** Acetylene	**C_2H_4** Ethylene	**C_2H_6** Ethane	**CO** Carbon Monoxide	**CO_2** Carbon Dioxide	**TDCG** See Notes
Cond 1	100	120	35	50	65	350	2,500	720
Cond 2	101-700	121-400	36-50	51-100	66-100	351-570	2,501-4,000	721-1,920
Cond 3	701-1,800	401-1,000	51-80	101-200	101-150	571-1,400	4,001-10,000	1,921-4,630
Cond 4	>1800	>1,000	>80	>200	>150	>1,400	>10,000	>4,630

Notes:

TDCG =Total Dissolved Combustible Gas (Excludes CO_2)

Cond 1 =Dissolved gas in this range indicates normal operation.

Cond 2 =Dissolved gas in this range indicates greater than normal gas generation. Begin analysis.

Cond 3 =Dissolved gas in this range indicates a high level of insulation decomposition. Sample frequently to establish the trend of gas evolution and apply gas ratio analysis for diagnosis.

Cond 4 =Dissolved gas in this range indicates excessive decomposition. Continued operation could result in failure of the transformer.

5.2 Review of Current Maintenance Plans

5.2.1 Compiling Maintenance History

To develop a clear picture of past equipment performance from which projections can be generated, a thorough review of the maintenance history is needed. This maintenance history is captured by most plants in Work Orders (WO), often managed by the plant computerized maintenance management system (CMMS). Work orders are written to execute preventive maintenance or corrective maintenance and to implement other activities, such as design changes, replacements, or upgrades.

The most important WOs are those implementing corrective actions as a result of equipment failures, performance enhancements, and design changes. They often contain information concerning the root cause of the failure to assure that the corrective action is effective, whether repetitive failures were involved, the cost and man-hours spent in the corrective action, and the reason why the failure was not detected in the incipient stages. This information is used to identify additional preventive maintenance (PM) or predictive maintenance (PdM) activities; potential enhancements to the current maintenance program; and/or the need for replacement, redesign, or upgrades. The basic premise is that the performance can only be improved by preventing failures; therefore, it is critical to identify the historical failure causes and to determine the action that could have prevented the failure.

The work order review also provides detailed information as to the component failure rates presently experienced by the large transformers. These rates can be compared with the generic data presented in Section 4 to ascertain whether there is the potential for significant reductions in failure rates. These actual failure rates are also used in the economic modeling of LCM plans to calculate the cost of corrective maintenance and the consequences of component failure (lost power production, regulatory cost, the costs of monitoring under the Maintenance Rule, EPIX reporting, etc.).

The work order review can also be used to trend the annual corrective maintenance activities over past years to see if the equipment failures are increasing or decreasing, and what additional corrective actions may be justified to effect a positive change.

Lastly and most importantly, a review should be conducted of all the plant transients, power reduction events, and scrams since plant operation began. This review should focus on the cause of the event, the principal systems or components involved, and whether the large transformer was a direct or indirect contributor to the event.

5.2.2 Inventory of Current Maintenance Activities

Once the plant-specific maintenance history has been compiled, the current maintenance activities need to be identified. When using the word "maintenance" in LCM planning, the activities associated with the system include preventive, predictive, and corrective actions, whether required by regulations (testing, inspection, surveillance, walkdown, monitoring, sampling), by applicable codes (ASME, NFPA, state requirements, local requirements); by the insurance carrier, or by plant procedures, programs, or policies. Collecting the associated activity parameters, such as the annual frequency of the task, the number of components involved, labor hours required, indirect labor associated with the activity, and the material costs, will provide the key input to developing a base case for LCM planning. This base case is not only important to create an inventory of the current activities and the total annual maintenance cost for the system, but it provides a benchmark for comparison to industry practice and a basis from which the need for additional activities, enhancements, or task reduction opportunities can be judged.

Intervals should be determined and adjusted by each utility based on individual plant experience, OEM information notices, and insurance and regulatory requirements. Intervals provided in the EPRI PM template are suggested starting points for this process, although in general, where these tasks are already being performed, the existing intervals could be used as the starting point providing a basis exists. Such a basis could be constructed from diagnostic data, past inspection data and failure history, and from information in this document. A key point is that it is prudent to change time-directed intervals so that intervals are short enough to protect against unacceptable equipment deterioration, but not so short as to waste maintenance resources or to introduce unnecessary sources of maintenance error.

When selecting time intervals for intrusive PM tasks, it is not necessarily conservative to select shorter rather than longer time intervals in a possible range. Shorter intervals expose the equipment to more opportunities for maintenance error and to the potential for non-optimal setup. Furthermore, reliability data for other complex plant component types suggest that components receiving a higher proportion of intrusive preventive maintenance tasks may experience more failures than those, which receive predominantly non-intrusive maintenance.

The following information should be considered when an inspection, maintenance, or a condition assessment is performed.

5.2.2.1 Pumps

Bearing wear and other mechanical failures in oil pumps are believed to be the cause of failure in some major power transformers. The particles generated can get into high stressed electrical areas causing failure. At the present time, there is no effective way to test pumps in service for such conditions; however the acoustic signature of the pump in operation could give an indication of problems, but this requires a baseline acoustic signature for comparison. It is recommended that the following actions be considered.

Some utilities recommend change-out of the oil pumps on a regular basis. The time interval depends on the time that the pumps are in operation and the experience with each pump design. All bearings, either sleeve or ball, will eventually become worn and require replacement.

- Industry experience shows that some pumps have a history of problems in service. It is recommended that these pumps be replaced when they have been in service for a long period of time. Replacement time depends on the maintenance program and the condition of the pumps.

- When pumps are replaced on operating transformers or on repaired units, it is recommended that the pumps either be replaced with new pumps that are reliable or be rebuilt with improved bearing systems.
- For large generator GSUs, it is recommended that consideration be given to the installation of pumps with bearing monitoring systems so that any problems can be detected before dangerous particles get into the transformer system.

The operating of pumps (and fans) on coolers should be rotated on a regular basis. They are usually arranged in groups that are activated by the cooler temperature controls. Rotating the groups will assist in balancing the wear on the pumps. Some utilities have automatic controls that rotate the groups that come on first each time that the cooling equipment is deactivated.

5.2.2.2 Bushings

High voltage bushings must be maintained free of any external contamination and should be examined on a regular basis. The porcelain insulation should be examined for chips, cracks, and oil leakage. The main objective is to prevent flashover that could lead to catastrophic failure.

External contamination builds continuously and might become severe enough to cause electrical breakdown after two to three years on non-coated bushings depending on conditions. It should be noted that bushing faults of various kinds are relatively common failure causes for oil-filled transformers. Inspection will be required more often in atmospheres where salts and dust deposits collect on bushings.

- Some utilities replace all bushings if the transformer is 20 years or older and life extension work is undertaken.
- Most utilities replace the bushings if the power factor is high. A common metric used for oil-filled bushings to indicate high power factor, is either a doubling of the initial value (nameplate) or a value greater than 1%, whichever is the lowest.
- Several utilities have replaced one type of bushing that has had a record of failures over the years with bushings having new and improved design features.

5.2.2.3 Control and Protective Devices

Some utilities replace all control and protective devices if a transformer life extension program is initiated. Such devices are low cost, and the risk is great enough on older transformers to justify the cost.

Such devices are sometimes tested and replaced if they are defective. Critical protective devices, such as sudden pressure relays, are quite often replaced if the transformer is approximately 20 years old. The control wiring is replaced if it shows signs of severe deterioration, which may be the case for older transformers.

5.2.2.4 Gas Cushion Oil Preservation

Super-saturation of the oil with nitrogen may result when the temperature of loaded transformers with gas cushion oil preservation system is decreased rapidly (by dropping the load in cold weather and/or rain). This problem is well known, and most utilities have replaced the pressure controls that allowed the pressure to increase up to 6 psig (41 kPa) before the system started to release the nitrogen to the atmosphere. The controls have been changed to release nitrogen at around 3 to 3.5 psig (20.5 to 24.1 kPa). For some important EHV transformers, the nitrogen system has been replaced with expansion tanks with rubber bags.

If the nitrogen cushion designs are not properly maintained, failure of transformers can result. If the bottle becomes empty and is not replaced, the pressure in the gas space can become negative causing gas bubbles to evolve from the saturated oil.

The cost to maintain such systems can be high (particularly for transformers with varying loads) such that the system releases nitrogen to the atmosphere at a high rate. The bottles of dry nitrogen have to be replaced frequently. In some cases, the overall cost can be reduced if the nitrogen system is replaced with an expansion tank. The replacement of the gas system with the expansion tank should be considered for life extension of transformers. If this decision is made, it is important to specify a non-gas permeable material be used as the membrane.

5.3 Conducting the Condition and Performance Assessment

The generic performance data and information presented in the preceding sections can be used for plant-specific LCM planning in many ways. In particular, for plants not having a large data basis of experience, the generic data provides a basis for a sound component-specific PM program. Furthermore, the data may be used for comparison trending or projecting performance or failure data into the future when attempting long-term LCM planning. If the plant is of recent vintage, the failure data provides an indication of the types of failures to be expected as the plant ages and shows potential precursors of problems to be anticipated. Lastly and most importantly, the benchmarking of plant-specific data against generic (or industry) performance data for large transformers provides LCM planners with information with which to focus on areas in which there are significant opportunities to achieve economic and technical improvements. The steps involved in plant-specific performance and condition assessment (including benchmarking) can be summarized as follows:

Transformer life is shortened by a number of events. In addition to these failures, controlling the characteristics of the internal transformer system, such as oxygen and water content, will extend transformer life.

Based on a review of the generic data on plant trips due to transformers, the most frequent trips occur due to:

- Bushing failures
- Spurious Sudden Pressure Relay (SPR) activation
- Lightning strikes

- Loss of cooling
- Inadvertent actuation of FP deluge system
- Gas-in-oil generation
- LTC failures
- Human errors

Although the above events are not in the order of frequency or significance, the information from reported events can be used to compare plant-specific performance data to generic (or industry) performance data for large transformers. In Section 4, Table 4.1 and Figure 4-3 show the cause of transformer events and failures due to transformer internal failures, external causes, and other causes. These events are based on INPO's gathering of information for the last 10 years. The benchmarking of plant-specific data against generic (or industry) performance data for large power transformers provides LCM planners with the information needed to focus on areas where significant opportunities to achieve economic and technical improvements exist. The steps involved in benchmarking can be summarized as follows:

- At the system level, benchmark the contribution of large power transformers to the total plant lost power generation against the industry PWR/BWR specific average (Table 4.2). This will provide a preliminary assessment as to the current and past plant system health and indicate if the large power transformers in the unit perform at, above or below industry averages with respect to lost power generation and associated impact on plant safety.
- At the component level, compare plant-specific transformer component failure rates with those discussed in Section 4.1 and Tables 4.1 and 4.6 (European data) to diagnose and identify potentially unacceptable component performance.
- Compare the plant-specific transformer maintenance tasks against the industry recommendations (Tables 4.3 to 4.5) to identify opportunities for addition or deletion of PM or PdM activities and adjustments to the associated task intervals. If the performance of the transformers has been exceeding the industry standards and failure rates are below average, changes to the transformer PdM/PM program should be implemented cautiously and with good reason. On the other hand, if the performance of the transformers measurably lags industry average and the plant transformer PdM/PM program significantly deviates from the industry recommendations, the deviations should be reviewed critically to identify the causes and any opportunities for enhancement.
- Review operating and loading practices to ensure transformer performance and operation are within rated values specified in the design and nameplate data provided by the manufacturer.
- Review the corrective work orders and root cause evaluations of transformer failures to determine if the failure causes are commensurate with the industry experience.
- Similarly, from the corrective work order review, tabulate the failure detection modes for the failed transformers to determine if the plant's preventive and predictive maintenance program is capable of detecting transformer degradation and incipient failures.
- To assure that the long term maintenance plans include a thorough and critical review of aging and obsolescence concerns, establish the plant transformer failure rates, projected spare

parts use, potential replacement models or refurbishment kits, current spare parts inventory, exchange or reuse opportunities and reliable suppliers of parts, services and replacements.

- Large transformers are usually custom made and it can take up to one year to obtain a new one. Rewinding also can take from six to twelve months. Therefore, the plant should identify alternate procurement methods such as identifying available spare transformers and possibly establishing supply agreements.

5.4 Condition Monitoring Technologies

A review of transformer inspection results and data from monitoring devices may require that further tests be performed. Analysis of the test results will provide information regarding the internal condition of the transformer, the next steps for further sampling, and the recommended test sequences.

5.4.1 Recommended Test Sequences

It is recommended that tests be performed in sequence as shown in Table 5.2, which is based on the principle of using oil testing to determine when further testing is required, depending on the condition of the dissolved gas concentration from Table 5.1.

Table 5-2
Recommended Test Sequences

Gas-in-Oil Tests	• Sampling ASTM D 3613
	• Analysis ASTM D3612
	• IEE Std. C57.104
Dielectric Tests	• ASTM D 1816 for the main tank oil
	• ASTM D 1816 and ASTM D877 for load tap changer compartments
Water-in-Oil Test	• ASTM D 1533
Oil Power Factor Test	• ASTM D 924
General Oil Tests	• Interfacial Tension (IFT) ASTM D 971
	• Color ASTM D 1500
	• Some utilities also make other tests such as acidity, viscosity, and oxidation stability. However, these tests are not usually recommended unless an extensive study is being made to determine if the oil should be replaced.
Insulation Power Factor Test	• IEEE Std. C57.12.90 Part 10.10 [6]
Other Possible Tests When Required	• Detailed oil tests • Particle count and identification

Table 5.3 [4] shows the recommended test intervals for the general and gas-in-oil tests. These intervals can be varied depending on the condition of the transformer, the history of the transformer, and the history of the transformer accessories. The frequencies shown are typical guidelines. If the transformers have a history of good operation with no problems, the time interval between tests can be increased. If there is indication of some abnormality, the time interval needs to be shortened.

The manufacturer's requirements should be followed for oil testing during the warranty period. If there are no such recommendations or requirements, it is recommended that all tests be made at the end of the first year in service and prior to warranty expiration. Subsequent testing should follow Table 5.2 if there are no other manufacturer requirements.

Table 5-3
Typical Maintenance Oil Test Frequency

	General Oil Tests	Dielectric & Water	Gas-in-Oil
Less than 100 MA three phase and 230 kV or less	1-3 years	1-3 years	1-3 years
Greater than 100 MVA three phase 230 kV or less	1-2 years	1-2 years	1-2 years
Greater than 100 MVA three phase, greater than 230 kV	1-2 years	1 year	1 year
All generator step-up	1-2 years	1 year	1 year

5.4.2 Gas-In-Oil Analysis

One of the most useful and widely used condition assessment techniques involves sampling and analysis of gases dissolved in the oil of operating transformers. Sampling intervals are typically from one to three years depending on the size and voltage of the transformer, with more frequent sampling for large, critical units and less frequent sampling for smaller, less critical units. There are three standards that address condition assessment sampling: ASTM D 3613 for analysis, ASTM D 3612 for interpretation, and IEEE Std C57.104-1991, "General Requirements for Liquid Immersed Distribution, Power and Regulating Transformers" [25].

The goal of the sampling process is to collect a representative sample, while avoiding entrance of contaminants, and to preserve the integrity of the sample until it is analyzed.

It is recommended that samples be taken from a convenient valve at the bottom of the tank, which may be equipped with a sampling adapter; the use of a syringe for sampling is preferred.

It is expected that dissolved gas content is well equilibrated within the tank as a result of thermal convection of the oil, but water content may be greater at the bottom. Normally the same samples are used for dissolved water and dissolved gas analyses. Samples may be taken from energized apparatus provided it is certain that a positive pressure exists at the sampling point. It could be disastrous if the pressure was negative and air bubbles were drawn into the equipment.

5.4.3 Dielectric Strength Guidelines

ANSI/IEEE Standard C57.106-1991, "Guidelines for Acceptance of Insulating Oil in Equipment" [7] has guidelines for the dielectric strength of oil in operating transformers, which are shown in Table 5.4. The recommended test limits are for oil in service and are suggested limits for continued use of service-aged insulating oil by voltage class. Standard C57.106-1991 [4] Section 5, provides additional information when tests do not meet the suggested limits. The values shown in the standard are approximately 7-15% lower than the recommended values for new oil in equipment after filling but before energizing.

Table 5-4
Dielectric Strength Guidelines

Test & Method	Minimum Dielectric Strength (kV)		
	< 69 kV	69-288 kV	> 345 kV
ASTM D 1816:			
• 0.040-in. (1-mm) gap	23	26	26
• 0.080-in. (2-mm) gap	34	45	45
ASTM D 877:			
• 0.100-in. (2.5-mm) gap	26	26	26

5.4.4 Dielectric Tests

Although the dielectric strength and water-in-oil tests are separate tests, oil samples for both tests are normally taken at the same time. There are two test methods available for determining the dielectric strength of oil. In the main tank, the ASTM-D-1816 method is used. This standard allows an electrode gap dimension of either 0.040 inches or 0.080 inches. Testing with the 0.040-inch gap is more widely used and recommended. Samples should be taken in accordance with ASTM-D- 3613 and D-923.

If the transformer has a load tap changer, either the ASTM-D-877 or the ASTM-D-1816 test method may be used. If the tap changer has sharp, uninsulated electrodes, the ASTM-D-877 method should be used. Generally, the ASTM-D-1816 method is more responsive to dissolved water and particles in oil. If the tap changer has the selector and diverter switches in separate compartments, samples should be taken from both compartments.

The standards do not contain information on the recommended oil properties for load tap changers. However, the following guidelines can be used for general application. It is recommended that the manufacturer's information be checked carefully for this information before taking action since it may be critical to the operation and life of the tap changer.

Typical oil dielectric characteristics for load tap changers are as follows:

- Compartments with no insulated parts or well rounded electrodes:
  ASTM D 877 minimum dielectric = 25 kV
- Compartments with insulated parts such as cables or all electrodes are well rounded:
  ASTM D 1816 minimum dielectric = 20 kV

These conditions can be determined from internal inspections. If no inspections have been made, well-rounded electrodes are usually used in diverter switches above 34 kV. The manufacturer can also furnish such information.

5.4.5 Water In Oil Tests

There are a number of commercially available equipment to perform tests in accordance with ASTM-D-1533. The results of these tests are used to determine the water content in the transformers. The samples should be taken in accordance with ASTM-D-3613 requirements to prevent contamination of the sample with atmospheric moisture.

Maximum recommended water contents for different voltage classes taken from IEEE Std. 637 and C57.106 are listed in Table 5.5.

Table 5-5
Maximum Water-in-Oil Test

	Voltage Classes		
Test	**< 69 kV**	**69 – 230 kV**	**> 230 kV**
Water content, ppm max. at 60°C	35	20	12

5.4.6 Water Content of Paper Insulation

Water reduces the dielectric strength of paper insulation. The amount of reduction depends on the stress pattern (puncture or creepage), the thickness of the insulation, and other variables.

If excessive water exists in the insulation and the transformer is overloaded, bubbles can form at the hot surfaces that are in contact with paper having high water content. The formation of bubbles is risky if the transformer having wet insulation is overloaded and hot spot temperatures, such as 150°C, exist. Wet insulation is also a factor in maintenance and life extension since the insulation ages faster when it contains high levels of water. The water content of the paper can be estimated from the water in oil and the temperature of the oil as given in EPRI "Guidelines for the Life Extension of Substations" [4].

Table 5.6 provides the EPRI guidelines for maximum water content in paper insulation.

Table 5-6
Maximum Water Content

kV of Highest Voltage Winding	Maximum Water Content
525 and 800 kV	1%
230 and 345 kV	1%
115 up to 230 kV	1.5%
Less than 115 kV	2.0%

If the water content is in line with the above limits, no action is required. If the water content is marginal, it is recommended that off-line insulation power factor tests be performed to obtain a better estimate of the water content. If these values are exceeded, consideration should be given to drying of the insulation.

Periodic tests to check the internal condition of the transformer are recommended at an interval of three to seven years even if the results from other tests are found satisfactory. Insulation power factor tests are not usually performed during these intervals unless problems with bushings or other components make these tests desirable.

5.4.7 Oil Power Factor

This test is used as a check on the deterioration and contamination of insulating oil, due to its sensitivity to ionic contaminants. The percentage maximum acceptable values for power factor are taken from Reference 4 and are given in Table 5.7.

Table 5-7
Maximum Acceptable Percent Power Factors of Oil

	Voltage Classes		
Temperature	**< 69kV**	**69 – 288 kV**	**> 345 kV**
20° C	1.0	0.75	0.5
100° C	3.0	2.0	1.5

The power factor of oil is measured using ASTM D 924.

Power factors above the acceptance levels usually indicate the following:

- Excessive water content in the insulation
- Contamination of the insulation
- Failure within the insulation structure, which has deposited carbon on the insulation

If the power factors are greater than the above typical limits, consideration should be given to processing the oil using one of the procedures in IEEE Std 637, "Guide for the Reclamation of Insulating Oil and Criteria for Its Use," 1982 [8]. The use of activated clay to remove contaminants from oil is the preferred method by many utilities. It is recommended that some experimentation be performed before starting the processing. Some contaminants can be removed by filtering the oil with clean, dry cellulose filters. More expensive clay filtering needs to be used to remove other contaminants.

This test is a means for detecting oil-soluble polar contaminants and oxidation products in insulating oils. Higher values than those in Table 5.7 are indicative of measurable dielectric loss resulting in heat generation during transformer operation and insulation deterioration. It is generally recommended that the oil be processed if the values are greater than those in Table 5.7.

5.4.8 Oil Interfacial Tension

Values of interfacial tension (IFT) below the minimum recommended acceptance values shown in Table 5.8, taken from IEEE C57.106 [7], are normally the result of oxidation byproducts or chemical contaminants. If all other oil parameters are normal, interfacial tension values below those recommended are not of immediate concern. However, it is recommended that any downward trends be followed since it may indicate a deteriorating situation. The interfacial tension is measured in accordance with ASTM D 971. Table 5.8 shows normal recommended test intervals for transformers with no signs of abnormal condition. Transformers with signs of insulation deterioration would require sampling more often depending on the oil condition. In such a case, trending is necessary to determine how often samples should be taken and what other steps may be required such as load reduction or outage scheduling.

Table 5-8
Oil Interfacial Test

	Voltage Classes		
Test	**< 69kV**	**69 – 288 kV**	**> 345 kV**
Interfacial tension	24	26	30

If the oil interfacial values are below the acceptable levels given in Table 5.8 and there is a downward trend, the oil can be processed using the procedures in IEEE Std 637, "Guide for the Reclamation of Insulating Oil and Criteria for Its Use," 1982 [8].

5.4.9 Condition Monitoring Systems

Considering a large transformer system, the condition assessment process can be improved if some characteristics and properties of the transformer system are monitored by additional on-line sensors. Although transformers are a critical part of electrical generation and transmission systems, there was not a major emphasis on improved monitoring until the 1990s.

The emphasis on reduced maintenance costs and life extension makes it desirable to have on-line monitoring systems that provide information for determining when maintenance should be performed.

On-line monitoring systems are becoming more common in recent years. In some cases, on-line monitoring systems can provide continuous data without the requirement for oil samples and analyses. Such systems can also provide trending data and charts for further evaluation and assist in the decision-making process. The following sections cover transformer condition monitoring methods and current technologies. Off line diagnostic tests and monitoring devices are covered in Section 5.1.3.

5.4.9.1 Gas-In-Oil Sensors

The objective is to employ on-line gas-in-oil measurement methods that will determine the amount of fault gases in the oil. These sensors are mounted so that they are exposed to the oil and detect the following gases:

- Hydrogen
- Carbon Monoxide
- Carbon Dioxide
- Acetylene
- Ethylene
- Ethane
- Methane
- Oxygen

5.4.9.2 Temperature Sensors

Top oil thermometers are commonly used but some utilities use resistance temperature devices (RTDs) for improved accuracy and reliability.

The so-called winding temperature devices are used on a large percentage of power transformers. The sensor is a simulation device that responds to the top oil temperature and the heat generated in a resistance element. A bushing current transformer provides current proportional to the load current to the heating coil. The current adds an increment of temperature to the coil that is equal to the winding temperature rise above the hot oil temperature. They have limitations in that the setting depends on the hot-spot temperature calculated by the designer, which may or may not represent the true hot-spot, and the time response of the winding may be different than that of the device.

Winding temperature devices that are commercially available at present no longer use a resistor to determine the increment of temperature added to the top oil temperature. Instead, the increment is calculated by software.

Direct measurement of hot-spot temperatures using fiber optic technology was investigated in an EPRI Report No. 1000016, "Optical Fiber Acoustic Sensors for Inside Transformer On Line Detection of Partial Discharges," [9] and such sensors have been successfully installed in a number of operating transformers. The sensors are located in an area that is either the hottest spot location or is representative of the hottest spot temperature. The fiber optic cables are made from an insulating material and are not suitable for installation in the higher voltage regions. Therefore, sensors must be installed in a lower voltage area such as the low voltage windings or in leads. They can also be installed in the winding oil ducts to determine the hottest oil temperature since the winding oil duct temperature may be several degrees hotter than the bulk top oil temperature. The fiber optic cables are taken through pass-through devices to the outside of the tank where they are connected to read-out or recording equipment. The obvious advantage is that the actual hot-spot temperature can be determined for life extension considerations or for loading purposes.

5.4.9.3 Oil Level Gauges

Oil level gauges are used to determine the level under different temperature conditions and to alarm if the level is below the minimum such that high-voltage parts might be exposed.

5.4.9.4 Rate-of-Rise Relays

The sudden pressure or fault pressure relay detects sudden pressure transients produced within the transformer tank during operation. It senses the rate of change of pressure during internal faults. If the internal pressure exceeds the safe limits, the relay will activate the tripping scheme to de-energize the transformer. This relay does not act as a pressure relief device.

It should be noted that installation of rate-of-rise relays on older transformers may require some study. For example, some older transformers may have loose windings that cause hydraulic pumping of the oil under low-level short circuits or even during magnetizing in-rush, which can activate the relay. In such instances, persons familiar with the transformer design and the relay design should be contacted.

5.4.9.5 Gas Collector Relay

The relay collects free gas bubbles in the oil. The relay is connected at the top of the transformer tank to collect the generated gas. If the gas is generated by partial discharges, excessive heating, or arcs under the oil, an alarm is initiated by the relay. The relays will also respond to air bubbles caused by leaks.

5.4.9.6 Oil Pump Performance Sensors

There are three types of devices in use:

- Differential pressure oil flow indicators are used to determine when the pumps are in operation.
- Vane-type oil flow indicators are also used to determine when the pumps are in operation.
- Pump bearing wear detectors are available for pumps having sleeved bearings. These acoustic devices are used to determine any changes in the dimension of the gap between the shaft and the bearing surface. Base readings are obtained when the pump is new. A read-out device is then used periodically to determine if wear has occurred.

5.4.9.7 Load Tap Changer (LTC) Monitors

A number of load tap changer monitors have been installed on transformers. The basic principle is that contacts that are nearing the end of their life or that are coking generate additional heat, which raises the temperature of the oil in the compartment. The tap changer diverter compartment usually runs cooler than the main tank, and the selector compartment runs cooler than the diverter switch compartment. If the temperature of the diverter switch compartment starts to increase in comparison to the main tank or the selector compartment, there is usually a contact problem. If the selector and the diverter are in the same compartment, the temperature of the tap changer compartment must be compared to the main tank.

Many LTC overheating problems have been detected with infrared scanning and on-line monitors. The on-line monitors use temperature sensors located on the walls of the tap changer compartments and the main tank. The output is connected to recording and analysis equipment. Alarms can be activated if the temperature of the diverter compartment reaches a level indicating that the contacts should be inspected or changed. Other monitors that are available for load tap changers include:

- Timing circuits to determine if there has been a change in the operating time of the mechanical system.
- Measurement of the motor current including the starting current. Broken shafts or changes in the mechanical system might be detected.

Load tap changer monitors under emerging technologies include:

- Use of ethylene gas analysis to determine contact wear. It has been found that the change in the ethylene is different when contact heating occurs compared to the other gases generated when the tap changer operates. Some utilities are already experimenting with ethylene detection using chromatograph data.
- Acoustic analysis is being used in much the same manner as is being applied to circuit breaker monitoring.

5.4.9.8 Infrared Thermography

Infrared thermography can be used on bushings and other connections to help detect problems. Pumps and load tap changers running hot can also be identified. It is less effective on the overall transformer tank due to the volume of oil and thickness of the steel. However, some hot spots near the tank wall have been detected using this technique. It can also be used to verify correct operation of the cooling radiators. A consistent thermal gradient from top to bottom of all radiators should be observed. Internal blockages and valves in the wrong position have been detected in this way. It is recommended that thermography be performed on the following transformer components:

- Control cabinet internals and terminal blocks
- Tank
- Bushings and connections
- Surge arresters
- Load tap changers
- Coolers, pumps and motors

5.4.9.9 Water-In-Oil Sensors

The operation of water-in-oil sensors is based on thin-film capacitive element technology. The capacitance measured will change proportionally to the change in the relative saturation of water in the oil. The output of these devices is the percent relative saturation of the water in the oil, which is dependent on the temperature of the oil and the amount of water in the oil. If the temperature of the oil is known, the parts-per-million (ppm) of water can be determined. The best sensors incorporate a temperature measurement device at the tip of the sensor, ensuring that the correct ppm can be determined.

5.4.9.10 Partial Discharge Detection

Partial discharge detection is of great interest. If detected early, damaging conditions can be remedied, thereby reducing repair costs and preventing catastrophic failures. Partial discharge detection has been used in transformer manufacturing since the 1960s to determine the presence of damaging discharges during factory tests. It is recognized that such detection has reduced the number of field failures by detecting incipient problems and taking corrective action in the factory.

5.4.9.11 Acoustic Emission Devices

Acoustic partial-discharge detection is used in factories for location of discharges, and this technology has been developed for field detection. Acoustic signals are generated in the oil by partial discharges so that this method involves sensing of the acoustic signals that are transmitted through the oil. Acoustic signals are also generated by the formation of gas bubbles and can be used to locate sources of overheating.

Piezoelectric devices are used to detect acoustic emissions from the transformer internals and have been installed on the transformer to obtain more data or as on-line monitors.

5.4.9.12 Acoustic Sensors

A number of acoustic sensors are attached at different locations on the wall of the transformer. The output from the sensors can be taken to read out devices or recorders. Data may be recorded and diagnosed using a computer system. If the signals appear in a transformer that has had no signal or if there is an increase such that there is an upward trend, an alarm is initiated.

5.4.9.13 Internal Sensors

The piezoelectric sensor is attached to the end of a fiberglass rod and the rod installed in the oil. The output of these sensors is transmitted to a computer system for recording and analysis. Alarms are initiated when a signal originates in a transformer with no previous discharge history or if there is an upward trend. EPRI is currently developing a fiber optic acoustic sensor for mounting inside the transformer. Report number 1001943, "Development of a Prototype Fiber-Optic Acoustic PD Sensor: For Inside Transformer Installation," is available [26].

6 GENERIC AGING AND OBSOLESCENCE ASSESSMENT

This section addresses the steps numbered 11B and 11C in the LCM planning flowchart (Figure 2-1b). The intent is to help characterize the aging of passive SSCs, the wear of active components, and the obsolescence of SSCs. This characterization will serve to address the need for and timing of the replacement of large transformer equipment in the LCM planning process and to identify potential environmental conditions that affect the rate of degradation or require special plant-specific attention.

6.1 Aging Mechanism Review

An aging management review is an integral factor to LCM maintenance planning. The aging management program (AMP) for large transformers was reviewed and two documents were identified in the NRC NUREG-1801, Vol. II, Generic Aging Lessons Learned (GALL) Report [16].

- VI.A, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- VI.B, Equipment Subject to 10 CFR 50.49 Environmental Qualification Requirements

Sandia report SAND93-7068-UC-523 [19], "Aging Management Guidelines," provides important information on maintenance and surveillance of power transformers and specific information to investigate for each transformer component. It also provides signs to look for during inspection and analysis/interpretation of monitoring results. Visual inspection can be performed during routine walkdowns or during scheduled maintenance. In addition to the Sandia report, EPRI document TR106857, "Preventive Maintenance Basis Volume 38: Transformers (Station-Type, Oil-Immersed)" [3] and EPRI 186-401 "User Guide - Long Term Reliability Prediction of Nuclear Power Plant Systems, Structures and Components" [18] contain a wealth of information on large transformer aging. Information contained in these documents can be used to identify the effects of aging on various components of large transformers and appropriate aging management programs.

The recommendations for aging management programs are derived from these three documents and are presented here. This approach ensures that the results of the aging management review can be readily used, and allows the plant staff to become familiar with and adopt the terminology that has evolved in the industry with respect to aging management activities. The recommendations from the above three documents are extracted and presented in Table 6.1.

Table 6-1
Common Maintenance Issues and Surveillance Techniques

Component	Aging Mechanisms	Aging Effect	Maintenance and Surveillance Techniques
Metal Enclosure (Tank) and Cover(s)	Rust, corrosion	Loss of wall thickness, metal cracks	Visual inspection of enclosure components and hardware; cleaning of exterior and interior enclosure surfaces (where accessible); painting of rusted or corroded portions of structure.
	Deterioration of seals or organic components (gaskets, seals)	Oil leakage, moisture intrusion	Visual inspection for embrittlement, cracking, or signs of fluid leakage; replacement as necessary.
	Metal fatigue	Structural integrity degradation	Visual inspection for missing screws, nuts, washers, and other fastening components; replacement as necessary.
Primary and Secondary Windings	Degradation of organic supports and spacers	Loss of separation between windings, clogging, impurities	Visual inspection of spacers, supports, and other insulating materials; insulation resistance testing; power factor testing; gas and oil evaluation.
	Formation of localized high temperature areas (hot spots)	Premature degradation of surrounding materials	Monitoring of hot spot, top oil, and other temperature indications; sampling and analysis of transformer insulating fluid for indication of decomposition byproducts and gases.
	Vibration, insulation degradation	Loosening of winding mounting systems, movement of windings in relation to one another	Frequency Response Analysis (FRA) test Visual inspection of winding mounting system for loose or damaged components; measurement of critical winding tolerances.
Magnetic Core	Core material embrittlement	Weakening or failure of lamination, increased eddy currents and core losses, insulation damage	Visual inspection for overheating or breaks in insulation/conductor; resistance and continuity testing.
	Loosening of core mounting system from design defects	Core dislocation, impact on fault current withstand, deterioration of insulation	Visual inspection of core mounting; core-to-ground test; measurement of critical core/winding tolerances.

Table 6-1 (continued)
Common Maintenance Issues and Surveillance Techniques

Component	Aging Mechanisms	Aging Effect	Maintenance and Surveillance Techniques
Insulation System	Dielectric breakdown of insulating fluid	Loss of dielectric strength, localized high temperatures in windings, combustible and non-combustible gases	Sampling and analysis for dielectric strength, power factor, water/impurity content, and combustible/non-combustible gases, as well as other analyses as applicable.
	Particulate and/or moisture contamination	Blockages, reduction in localized heat dissipation, reduction in dielectric strength	Visual inspection of insulating fluid for signs of impurities or water; dielectric strength and power factor testing; laboratory analysis for water content.
	High acidity	Deterioration and decomposition of solid insulating materials, insulation degradation	Sampling and laboratory analysis (neutralization number)
	Oxidation and sludge formation	Reduced efficiency of cooling system, increased acidity of insulating fluid	Visual inspection of insulating fluid; laboratory analysis for sludge and inhibitor content; maintenance of seals and airtight integrity of tank and oil preservation system components.
Bushings	Degradation of organic materials	Paper, gasket, and seal degradation	Power factor and capacitance testing.
	Contamination or deterioration of porcelain exterior surfaces	Formation of conductive path (tracking) along surface of rain shields, flashover	Visual inspection for dust, salt, contamination, cracking, streaking, discoloration, or chipping of porcelain insulator; cleaning, coating, or replacement as necessary.
	Dielectric breakdown, bushing insulating fluid exposure to ambient conditions	Deterioration and leakage of oil/inert gas	Visual inspection for indications of leakage; verification of bushing oil level; replacement of gaskets/seals as required.
	Improper strain on connection or mechanical stress, flashover	Electrical connection damage or loosening	Verification of connection tightness and check for excessive strain (outage). Thermography

Table 6-1 (continued)
Common Maintenance Issues and Surveillance Techniques

Component	Aging Mechanisms	Aging Effect	Maintenance and Surveillance Techniques
Cooling System	Motor, cooler fan, and pump wear	Bearing wear depends on type, frequency of lubrication, and service conditions. Undue vibration, friction, noise, loss of shaft tolerances.	Visual inspection of motors, fans, pumps. Periodic maintenance. Winding insulation resistance testing; replacement of motors and/or leads as required.
	Radiator, fins, tubes clogging	Reduction of heat dissipation	Visual inspection and cleaning of radiators, fins, tubes; verification of adequate air flow. Thermography
Load Tap Changers	Wear of mechanical components	Increased friction and accelerated wear	Visual inspection. Periodic adjustment and parts replacement as necessary based on inspection and maintenance.
	Wear of electrical components	Friction and accelerated wear of surface contacts	
	Thermal aging of insulating materials	Reduction of dielectric strength	
	Wear of main contacts		
	Deterioration of contacts	Tap changer compartment leakage	Visual inspection for leakage or deteriorated gaskets; verification of proper oil level.
Sudden Pressure Relay (liquid only)	Thermal aging	Degradation of organic seals and gaskets	Visual inspection for signs of leakage, cracking, or other gasket/seal degradation; functional testing.
Bushing Current Transformers	Thermal aging	Degradation of organic insulating materials	Insulation inspection; insulation resistance testing.
Pressure Relief Devices	Thermal aging	Degradation of seals	Periodic testing for functionality; visual inspection for seal degradation
Temperature Indicators	Thermal aging	Failure of hot spot heating oil element	Periodic verification of temperature sensor functionality and accuracy.

6.1.1 Other Sources of Generic Failure Data

Failure data for components used in large transformers is presented in Table 3.1 of EPRI TR-106857-V38 [3], and is reproduced in Table 6.2. The data indicates specific transformer components, the degradation mechanisms, failure timing, and PM required to prevent such an event.

Table 6-2
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Transformer Oil (mineral)	Loss of dielectric strength	▪ Heat from normal operation	Continuous	Expect to be failure free for ~20 years Expect to be failure free for at least several years	Temperature monitoring DGA Partial DGA Oil dielectric test Oil screening Oil power factor testing	Oil screening DGA Operator rounds
		▪ Moisture ▪ Contamination (particulate)		Expect to be failure free for at least several years		
		▪ Low energy electrical discharge		Expect to be failure free for ~20 years		
		▪ Arcing	Random	Random on a scale of months		
Windings	Insulation breakdown	▪ Abnormal temperature rise	Random	Random, on a scale of 8 years at 90 C oil temperature or 110 C winding hot-spot temperature	Electrical tests: Power factor Turns ratio test Insulation resistance Oil analysis Thermography Vibration analysis Acoustic monitoring Gas blanket monitoring Oil testing for furfural Degree of polymerization of cellulose sample Partial discharge testing	Calibration and testing * Oil screening DGA Thermography Vibration/acoustic/ sound testing

**Table 6-2 (continued)
Degradation Mechanisms**

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Windings (cont.)		▪ Moisture	Continuous	Expect to be failure free for several years		
		▪ Arcing	Random	Random on a scale of a month, can be rapid		
		▪ Aging: ▪ Heat of operation ▪ Corona	Continuous	Expect to be failure free for 40 years		
		▪ Partial discharge	Random	Random on a scale of several years		
		▪ Voltage surge		Random, depending on degree and number of events		
		▪ Oil quality	Continuous	Expect to be failure free for 5-7 years		
		▪ Mechanical losses	Random	Random		
Core	Loose	▪ Assembly of shipping error ▪ Vibration	Random and continuous Continuous	Expect to be failure free for 40 years, assuming oil is degassed as needed	DGA Vibration Sound level	DGA Vibration/acoustic/ sound Testing
	Loss of core ground	▪ Assembly or shipping error ▪ Vibration	Random and continuous Continuous	Expect to be failure free for 40 years, assuming oil is degassed as needed	Core ground testing	Calibration and testing
	Multiple core grounds	▪ Assembly or shipping error ▪ Vibration	Random and continuous Continuous	Expect to be failure free for 40 years, assuming oil is degassed as needed	DGA	DGA

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Core (cont.)	Shorted laminations	▪ Heat from over excitation or arcing ▪ Poor manufacturing ▪ Shipping or handling error	Random	Random, on a scale of years Random	DGA Turns ratio Single phase excitation current	DGA Calibration and testing
Gaskets	Leakage	▪ Aging from thermal cycling and stray eddy currents	Continuous	Expect to be failure free for about 20 years	Inspection	Operator rounds Engineering walkdown
		▪ Improper assembly ▪ Overpressure	Random	Random		
Tank	Corrosion	▪ Sulfur contamination	Random	Random on a scale of ~5 years, if tank is contaminated	Oil screening Sulfur test	No task
Oil Filled Bushings	Leakage	▪ O-ring failure	Continuous	Expect to be error free for at least 15 years	Inspection	Operator rounds Engineering walkdown
		▪ Over-temperature chipped or cracked porcelain ▪ Improper maintenance techniques	Random	Random		Bushing cleaning Maintenance inspection
	External contamination	▪ Environmental conditions	Continuous	Expect to be failure free for 2 to 5 years, depending on severity of conditions	Monitor a spare bushing Thermography Ultrasonic testing Audible noise Inspection	Thermography Operator rounds Engineering walkdown Vibration/acoustic/ sound testing Bushing cleaning Maintenance inspection

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Oil Filled Bushings (cont.)	Loss of BIL	▪ Internal contamination ▪ Operation above rating ▪ Low oil level ▪ Voltage surges (e.g. lightning strikes) ▪ Manufacturing techniques ▪ Improper maintenance ▪ Chipped or cracked porcelain	Random Continuous Random	Random	Electrical testing: Power factor Capacitance Inspection	Calibration and testing Maintenance inspection
Solid Bushings	Loss of BIL	▪ Chipped or cracked porcelain ▪ External contamination	Random	Random	Inspection Electrical testing: Power factor Capacitance	Maintenance inspection Calibration and testing
Lightning Arresters: (metal oxide varistor type)	Thermal runaway	▪ Aging	Continuous	Random	Electrical testing: Power factor Leakage current	Calibration and testing Lightning arrester leakage monitoring
No-Load Tap Changer	Misalignment, Contact Coking, etc.	▪ Wear and binding of mechanism ▪ Number of operations	Continuous	Random	Electrical testing Turns ratio test DGA	Calibration and testing DGA
	Sheared gear pin	▪ Binding of mechanism	Continuous	Random	Operation	No task
Load Tap Changer	Misalignment, Contact Coking, etc.	▪ Wear and binding of mechanism ▪ Number of operations	Continuous	Random	Timing test Turns ratio test DGA Thermography	Tap changer maintenance Calibration and testing DGA Thermography
		▪ Improper maintenance	Random			

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Load Tap Changer (cont.)	Damaged contacts	▪ Normal wear	Continuous	Expect to be failure free for > 100,000 cycles	Timing test Turns ratio test DGA Thermography Acoustic monitoring	Tap changer maintenance Calibration and testing DGA Thermography Vibration/acoustic/ sound level
		▪ Lack of use		Random, but could be a small number of cycles		
		▪ Oil quality ▪ Misalignment ▪ Improper maintenance	Random	Random		
	Leaks: gasket, piping and valves	▪ Aging ▪ Wear	Continuous	Expect to be failure free for 20 years	Inspection DGA	Operator rounds Engineering walkdown Tap changer maintenance DGA
	Motor operator failure	▪ Overload: linkage binding ▪ Exceeding duty cycle	Continuous Random	Random Random, on a scale of years	Operator counter Inspection	Tap changer maintenance Engineering walkdown
Fins and Tube Coolers (Oil Coolers	Airside fouling	▪ Air quality ▪ Debris	Continuous Random	Random Random, can be months	Inspection Oil temperature monitoring	Operator rounds Cooler maintenance Engineering walkdown
	Loss of heat transfer	▪ Internal oil sludging	Continuous	Expect to be failure free for 40 years	Inspection Oil temperature monitoring Thermography	Cooler maintenance Operator rounds Thermography
		▪ External corrosion		Expect to be failure free for 15-20 years		

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Fins and Tube Coolers (cont.)	Leaks: tube to header	▪ Thermal expansion ▪ Vibration ▪ Dissimilar materials ▪ Manufacturing defect	Continuous	Expect to be failure free for 40 years	Inspection	Operator rounds Engineering walkdown Cooler maintenance
			Random	Random, on a scale of 20 years		
	Leaking gaskets	Aging from thermal cycling and stray eddy current Improper assembly	Continuous	Expect to be failure free for about 20 years	Inspection	Operator rounds Engineering walkdown Cooler maintenance
			Random	Random		
	Dresser coupling leaks	Improper installation Improper design	Random	Random, can be immediate	Inspection	Operator rounds Engineering walkdown Cooler maintenance
Radiators	Airside fouling	Debris	Random	Random	Inspection Oil temperature monitoring	Operator rounds Cooler maintenance Engineering walkdown
	Loss of heat transfer	Low oil level	Random	Random, could be rapid	Inspection Thermography Oil temperature monitoring Oil analysis Loss of oil flow	Operator rounds Oil screening Engineering walkdown Thermography
		Oil sludging	Continuous	Expect to be failure free for 40 years	Inspection Thermography Oil temperature monitoring Oil analysis	Operator rounds Oil screening Engineering walkdown Thermography
Fans and Motors	Bearing wear	Age Excessive lubrication Lack of lubrication	Continuous	Expect to be failure free for 7 to 10 years	Vibration monitoring Motor current Thermography Acoustics monitoring Lubrication	Thermography Vibration/acoustic/ sound testing Cooler maintenance Motor current monitoring

**Table 6-2 (continued)
Degradation Mechanisms**

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Fans and Motors (cont.)		Fan blade imbalance	Random	Random		
	Winding insulation failure	Age	Continuous	Expect to be failure free for 40 years	Insulation resistance	No task
		Water ingress at connections	Random	Random		
	Fan blade cracks	Fatigue Corrosion	Continuous	Expect to be failure free for 40 years	NDE Inspection	Cooler maintenance
		Imbalance Improper maintenance	Random	Random		
	Motor power cable deterioration	Age Heat Sunlight	Continuous	Expect to be failure free for 10-15 years	Inspection	Cooler maintenance
Pump and Motor	Bearing wear	Age	Continuous	Expect to be failure free for 40 years **	Vibration monitoring Motor current Bearing wear indicator Acoustics monitoring Ferrography	
	Impeller and volute wear	Age	Continuous	Expect to be failure free for 40 years	Vibration monitoring Motor current Acoustics monitoring Ferrography Flow indication	Vibration/acoustics/ sound testing Motor current monitoring Operator rounds Engineering walkdown
	Winding insulation failure	Age	Continuous	Expect to be failure free for 40 years	Insulation resistance	No task
		Water ingress connections	Random	Random		
	Motor power cable determination	Age Heat Sunlight	Continuous	Expect to be failure free for 10-15 years	Inspection	Cooler maintenance
Valves	Stem leaks	Aging Heat	Continuous	Expect to be failure free for 10 years	Inspection	Operator rounds Engineering walkdown

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Valves (cont.)	Disk detachment	Pin broken or dislodged	Random	Random	Operation	No task
	Bound or struck	Lack of use	Random	Random, on a scale of 10 years	Operation	No task
	Air In-leakage	Stem leak	Continuous	Expect to be failure free for 10 years	Oil pressure gauge Oil level DGA	Operator rounds DGA
Sudden Pressure Relay	Mis-operation	Age (switch, spring, and diaphragm)	Continuous	Expect to be failure free for 40 years	Functional test Replacement	Calibration and testing
		Vibrates loose Installation error	Random	Random		
Buckholtz Gas Volume Relay	Mis-operation	Installation error Maintenance error	Random	Random	Functional test	Calibration and testing
		Bound or broken linkage	Continuous			
Level Alarms	Mis-operation	Installation Maintenance error	Random	Random	Functional test	Calibration and testing
		Bound or broken linkage	Continuous			
Pressure Gauge	Drift	Age	Continuous	Expect to be failure free for 5-7 years	Calibration	Calibration and testing
Temperature Gauge	Draft	Drift	Continuous	Expect to be failure free for 4-6 years	Calibration	Calibration and testing
Conservator Tank	Bladder failure	Age	Continuous	Expect to be failure free for 40 years	DGA Inspection	DGA Maintenance inspection
	Fittings and connection leaks	Installation error Vibration	Random Continuous	Random Expect to be failure free for 40 years	Inspection	Operator rounds Maintenance inspection Engineering walkdown
		Stray eddy currents (at main tank connection)	Random	Random, on a scale of 2-3 years after occurrence		
Desiccant	Outlet breather valve fails to seal	Age Environment	Continuous	Expect to be failure free for 40 years	DGA	DGA
	Depletion	Moisture	Continuous	Expect to be failure free for a few years	Inspection	Operator rounds

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Gas Blanket Systems	Regulator failure	Drift Elastomer failure.	Continuous	Expect to be failure free for 10 years	Inspection Alarm	Operator rounds Engineering walkdown
	Leaking: pipes, tubing, fittings, gaskets and valves	Age Vibration	Continuous	Random	Inspection Alarm	Operator rounds Engineering walkdown
Relief Valve	Improper operation	Age Corrosion	Continuous	Random	Inspection Alarm	Operator rounds Engineering walkdown
Electrical Connections	Loose	Vibration Thermal cycling	Continuous	Random	Inspection Thermography	Maintenance inspection Thermography
Control Relay	See EPRI Report TR 106857, Volume 30, Relays-Control					See EPRI Report TR 106857, Volume 30, Relays-Control
Timing Relay	See EPRI Report TR 106857, Volume 31, Relays-Timing					See EPRI Report TR 106857, Volume 31, Relays-Timing
Motor Starters, Breakers, and Transfer Contactors: Wiring, Fuses, and Lights	See EPRI Report TR 106857, Volume 8, Low Voltage Electric Motors (600V and below)					See EPRI Report TR 106857, Volume 8, Low Voltage Electric Motors (600V and below)

Note: The above Table 6.2 (Ref. 3) is reproduced from EPRI's TR-100806 report. The following comments are offered to clarify items not clearly listed.

* Calibration refers to testing equipment.

** Pumps and motors are not expected to be failure free for 40 years. (See Section 5.2.2.1.)

6.2 Expected Lifetimes of Major Components

In addition to long-term aging of passive components, active components of large transformers are susceptible to wear or degradation. This degradation must be addressed by routine preventive maintenance, including overhaul and component replacement. Typical failure timing for active transformer components is presented in Table 6.2, together with information on degradation influence and cause. It should also be noted that the maintenance (corrective or preventive) entailed in replacing worn out components can be addressed through the maintenance programs identified in Section 5.4, considering the failure rates discussed in Section 4.1.2.1 (Table 4.1).

6.3 Technical Obsolescence

Guidance is provided using the evaluation method provided in Table 2.2 of the Life Cycle Management Sourcebook Overview Report [1].

Many systems in a nuclear power plant (and in particular those with electronic instrumentation) are susceptible to technical obsolescence. Components may have to be replaced because of the unavailability of spare parts. In these cases, the likelihood and timing of the need to perform replacement of the system or components will be determined by the failure (or degradation) rate of the part, and availability of spares from other sources. The feasibility and cost of reverse engineering the obsolete components should also be considered.

To ascertain whether a given system is susceptible to technical obsolescence, the evaluation method provided in the Life Cycle Management Sourcebook Overview report [1] (shown as Table 6.3) can be applied as a first step. Using the criteria from this table emphasizes the seriousness of technical obsolescence for the following reasons:

- There are very few transformer manufacturers left in the voltage class of 138 kV and higher.
- Tertiary winding loading demands a new design.
- UATs and RATs/SATs are two, three, and in some cases four winding type transformers which require special design to accommodate the physical configuration of the windings in the same tank. Some transformer manufacturers decline to build multiple winding transformers and utilities often have no choice but to find overseas manufacturers and pay the added shipping cost.
- The bushing arrangements for GSUs and UATs are unique because of isophase bus connections.
- Bushings are long lead components and replacing them requires an outage. Therefore, planning and scheduling is essential to avoid unnecessary plant shutdowns and loss of revenue. In some cases, older bushings may not be available and additional engineering tasks may be required.
- Special design is required to account for generator characteristics and sudden load drop during a turbine trip.

- Special insulation design is required for a delta connection on the HV side.

These characteristics do not lend themselves to an immediate delivery when required. It may be worthwhile to quote SOER 02-3 (19) as follows:

- Many original equipment manufacturers are no longer in business and many stations are depending on other transformer vendors for service and technical support.
- The unique design of each transformer contributes to difficulty in sharing and learning from industry experience.

This aspect of obsolescence should be addressed in developing LCM alternatives. Table 6.3 identifies an example of the application of obsolescence evaluation for a cooling fan.

Table 6-3
Application of Obsolescence Evaluation Criteria for a Cooling Fan

	Technical Obsolescence Evaluation Criteria	Score	Yes
1.	Is the SSC still being manufactured and will it be available for at least the next five years?	5.0	
2.	Is there more than one supplier for the SSC for the foreseeable future?	3.0	
3.	Can the plant or outside suppliers manufacture the SSC in a reasonable time (within a refueling outage)?	3.0	
4.	Are there other sources or contingencies (from other plants, shared inventory, stock-piled parts, refurbishments, secondary suppliers, imitation parts, commercial dedications, etc.) available in case of emergency?	3.0	3.0
5.	Is the SSC frequency of failure/year times the number of the SSCs in the plant time the remaining operating life (in years) equal or lower than the number of stocked SSCs in the warehouse?	3.0	
6.	Can the spare part inventory be maintained for at least the next five years?	3.0	
7.	Is the SSC immune to significant aging degradation?	1.0	1.0
8.	Can new designs, technology, concepts be readily integrated with the existing configuration (hardware-software, digital-analog, solid-state, miniaturized electronics, smart components, etc.)?	3.0	3.0
9.	Is technical upgrading desirable, commensurate with safety and cost effective?	3.0	
	Total Obsolescence Score:		7.0

Ranking Guidance for Table 6.3

- Total score is < 6.0, RED and the SSC obsolescence is serious. Potential options to deal with obsolescence and contingency planning should be identified. Guidance on the modeling, timing and costs of these contingencies, and the associated risks should be provided.
- Total score is between 6.0 and 10.0 YELLOW, and the SSC may have longer term concerns for obsolescence. Contingency planning and options should be considered.
- Total score is > 10, GREEN and the SSC is not likely affected by obsolescence.

The score of 7.0 for the example component in Table 6-3 indicates that contingency planning and obsolescence mitigation options should be addressed in one or more alternative LCM plans.

7
GENERIC ALTERNATIVE LCM PLANS

This section addresses steps 12-17 in the LCM planning flowchart (Figure 2-1b) to provide guidance for developing alternative plans. The EPRI LCM Demonstration Program Report [2] summarizes alternative LCM plans as follows:

> *"Following the assessment of aging and reliability, potential alternative LCM plans should be identified. The objective here should be to explore whether there are potentially better ways of addressing the aging management of the SSC. These inputs can come from plant staff but input should also be solicited from outside experts and industry benchmarking projects."*

The following guidance for these steps includes the identification of possible plant operating life strategies and the development of alternative LCM Plans that are compatible with or integral to the strategies identified. Also provided is a hypothetical illustration of alternative LCM plans (for large transformers) with the attendant discussions of the logic for building the alternatives and the derivation of assumptions.

7.1 Plant Operating Strategies and Types of LCM Planning Alternatives

The determination of LCM planning alternatives will be driven mainly by the plant operating strategies that, implicitly or explicitly, are being followed or evaluated and the current reliability performance of large transformers and component parts. Accordingly, the LCM planning alternatives that will be evaluated are very plant-specific. The typical plant operating strategies and standard approaches to LCM planning alternatives are discussed below.

7.1.1 Plant Strategy 1: Operate the plant for the currently licensed period of 40 years.

This strategy requires minimizing risk during the remaining operating period until the plant's license expires and identifying limiting SSCs which could result in premature power reduction or replacements forcing an economic decision regarding early decommissioning. LCM plan alternatives that might be developed under this strategy include:

- **LCM Plan Alternative 1A:** A base case to determine the cost of the activities performed under the current maintenance plan, and assuming that the activities will continue as-is until the end of the licensed plant life. This case also assumes the ***continuation of the existing maintenance program*** without any major capital investments, unless absolutely necessary.

- **LCM Plan Alternative 1B:** An alternative plan in which the current maintenance plan is optimized and ***an aggressive PM program*** is implemented to reduce equipment failures, lost power production, and regulatory risk.
- **LCM Plan Alternative 1C:** An alternative in which the current maintenance plan is optimized and ***older transformers are refurbished/replaced*** with more reliable equipment. Variations to this alternative are schemes such as:
  - Transformers with larger temperature rise boundaries
  - Consideration of a three-phase unit in one tank against three-single-phase units in three separate tanks, or three-phase half size, in two tanks
  - Refurbishment of the transformer by retaining the core
  - Additional radiator cooler banks or chilled water system

7.1.2 Plant Strategy 2: Operate the plant for 60 years under a License Renewal Program

This strategy recognizes the potential for license renewal and extended operation of the plant. Major investments will be required to achieve extended operation. These investments can only be justified by additional revenue generated in the additional 20-year operating term. LCM planning alternatives that might be considered under this strategy include:

- **LCM Plan Alternative 2A**: A rigorous preparation for license renewal with an aggressive aging management program, system performance enhancements, and timely component replacements or upgrades. This LCM plan recommends timely replacement of like-for-like components such as pumps, fans, motors, level and temperature indicators, etc.
- **LCM Plan Alternative 2B:** Preparing for eventual license renewal with an aggressive PM and PdM program, but delaying plans for major capital improvements until the actual extended license is implemented (i.e., in year 35 of the plant life).

7.2 Development of Detailed Alternative LCM Plans

For each alternative LCM plan proposed, detailed maintenance activities and schedules need to be identified. Each plan will involve some mix of the LCM approaches in steps 13 to 17 in Figure 2-1b. This section will provide guidance in developing the alternative LCM plans. The following may be considered when developing the alternative LCM plans:

- Adjusting the frequency of time-directed maintenance activities to enhance the reliability of the large transformers or reduce maintenance costs.
- Considering diagnostics (PdM) to convert from time-directed to condition-directed maintenance.
- Performing preventive and non-invasive maintenance activities on-line, if feasible.
- Adding routine preventive and predictive maintenance activities that might enhance the reliability of large transformers. A number of these activities are listed in Section 4.1.5.

- Tasks that are specifically devoted to transformer aging. While many of the routine maintenance tasks performed on or proposed for large transformers might broadly be regarded as being intended to address aging, a number of tasks are identified in Table 6.1, "Common Maintenance Issues and Surveillance Techniques," of Section 6 that specifically address the aging of passive components. The addition (or deletion) of these tasks should be considered in alternative LCM plans.
- Tasks that address, facilitate or enable operating changes to minimize or equalize component wear. For example, the flow of oil into the bottom of the winding can be modified and optimized by changing the sequence of pump activation to avoid high flow into the bottom of any phase. This reduces static electrification and increases reliability. By staging the pumps as shown in Table 7.1, efficiency can be optimized. Installation of run-time meters and start counters can help ensure pumps are run equally, thus avoiding excessive wear on any one pump. Start counters also facilitate the scheduling of time-directed maintenance for active stand-by equipment.

Table 7-1
Guide for Staging of Pumps on Forced-Oil-Air (FOA) Transformers

No. of Pumps	Group 1	Group 2	Group 3
3	1	1	1
4	1	1	2
5	1	2	2
6	2	2	2
7	2	2	3
8	2	3	3

7.3 Hypothetical Illustration of Assembling LCM Planning Alternatives

This section illustrates the process of creating LCM planning alternatives. A hypothetical case is discussed with assumptions identified.

The recent improvements in the design of oil-filled transformers have been in the technology of better insulation characteristics. New insulation has allowed transformers to be built to operate at higher temperatures, voltages, and with larger tanks. The transformer life is guaranteed only if the insulation is preserved in conjunction with the mechanical components like bushings, LTC, accessories, and the cooling system. During the life of a transformer, all components undergo wear and aging due to operating conditions. If the unit is operated within its nameplate ratings with minimal tap change operations, transformers should operate for the design life.

Many of the components like LTCs, bushings, accessories, pumps, coolers, etc., can be replaced once a faulty condition is detected. These are reversible life components which, when replaced in a timely manner, will help to extend the life of the transformer. However, there is one major component of the transformer that, once subjected to abnormal condition, cannot be restored to its original condition -- it is the transformer solid insulation.

The transformer solid insulation degradation is an irreversible event. Once aging begins, it is an irreversible degradation process, which determines the life of the transformer. Therefore, the preservation of the transformer insulation is of paramount importance for preserving the life of the transformer. The oil that is used to remove the heat also serves as a part of the insulation scheme.

All transformers undergo some kind of aging, but the older large transformers need special attention. Replacement of these transformers is not easy because the original manufacturers may no longer be in business, particularly in the voltage class 138 kV and higher. Therefore, this case is not a hypothetical situation but a very real threat. Apart from requiring a higher voltage rating, the large utility transformer requires special terminal arrangement, matching transformer and generator characteristics, higher BIL, and customized reactance matching.

Based on this unique situation, alternatives must be in place for continuous plant operation. When preparing the alternative LCM plans the following may be considered:

- Review original design with an objective of "fit-for-service" status (items such as BIL and short circuit capability).
- Analyze the system disturbance, impact on the transformer (e.g. through-faults, lightning strikes, frequency and voltage swings).
- Consider monitoring the loading very closely.

The following items may be considered as LCM planning progresses:

- A spare GSU, UAT or RAT/SAT is a prudent investment for plants that have one of each of these transformers. Maintaining a spare for half-size GSUs in large power plants may not be as critical since half of the generating load can be carried with one transformer. However, considering the revenue losses for the time to repair or receive a new transformer, the cost for maintaining a spare is small.
- Power plants with two auxiliary transformers per unit may have the flexibility to carry all the station auxiliary power loads with one transformer if the other UAT is out of service. Of course, the load carrying capacity depends on the size of the transformer. Some newer plants have GSUs, UATs, and RATs/SATs with additional excess capacity.
- Table 7.2 provides a sample cost analysis and the process of creating LCM planning alternatives. The inspection, maintenance, and repair frequencies as well as the cost associated with these tasks are approximate numbers. The effort here is to provide a hypothetical illustration that can be followed as an example when actual costs are known in order to choose the best alternative.
- Labor hours used in the hypothetical illustration are different for daily and monthly inspections. Monthly inspections involve more detailed tasks.
- Labor charges may be higher for outside contractors compared to in-house personnel. Outside contractors may not be as well informed as in-house personnel regarding plant-specific equipment.

Table 7-2
Hypothetical Example for Single Tank, Single Unit, 3-Phase Transformer

Item #	Activity Description	No. of Comp.	Labor Hours	Labor Cost ($)	Mat. Cost ($)	Frequency/ Year	Alt. A Existing Maintenance Program	Alternative B Partial Upgrade & Aggressive PM Program	Alternative C Refurbishment & Aggressive PM Program	Alternative D New Transformer & Aggressive PM Program
1.1	Inspection									
1.1.1	Daily	1	1	60		365	21,900	21,900	21,900	21,900
1.1.2	Monthly	1	2	60		12	1,440	1,440	1,440	1,440
1.1.3	Daily	1	1	60		365	21,900	21,900	21,900	21,900
1.1.4	Monthly	1	2	60		12	1,440	1,440	1,440	1,440
1.2	Calibration (every 18 months)									
1.2.1	Protective relays	10	8	60		0.5	2,400			
1.2.2	Sudden pressure	1	4	60		0.5	120			
1.2.3	Pressure relief	1	4	60		0.5	120			
1.2.4	Indicators (temp. & level)	6	16	60		0.5	2,880			
1.2.5	Gas accumulator	1	8	60		0.5	240			
1.2.6	Protective relays	10	8	60		0.75		3,600	3,600	3,600
1.2.7	Sudden pressure	1	4	60		0.75		180	180	180
1.2.8	Pressure relief	1	4	60		0.75		180	180	180
1.2.9	Indicators (temp. & level)	6	16	60		0.75		4,320	4,320	4,320
1.2.10	Gas accumulator	1	8	60		0.75		360	360	360
1.3	Oil sampling									
1.3.1	Oil sampling	1	4	60	200	1	440			
1.3.2	Oil sampling	1	4	60	200	2		880	880	880

Table 7-2 (continued)
Hypothetical Example for Single Tank, Single Unit, 3-Phase Transformer

Item #	Activity Description	No. of Comp.	Labor Hours	Labor Cost ($)	Mat. Cost ($)	Frequency/ Year	Alt. A Existing Maintenance Program	Alternative B Partial Upgrade & Aggressive PM Program	Alternative C Refurbishment & Aggressive PM Program	Alternative D New Transformer & Aggressive PM Program
1.4	Thermography									
1.4.1	Thermography	1	4	60	100	1	340			
1.4.2	Thermography	1	4	60	100	2		680	680	680
1.5	Maintenance									
1.5.1	Radiators/coolers	16	8	60	500	1	8,180			
1.5.2	Radiators/Coolers	16	8	60	500	2		16,360	16,360	16,360
1.5.3	Motor fans	24	8	60	500	1	12,020			
1.5.4	Motor fans	24	8	60	500	2		24,040	24,040	24,040
1.5.5	Oil pumps	4	16	60	1000	1	4,840			
1.5.6	Oil Pumps	4	16	60	1000	2		9,680	9,680	9,680
1.5.7	Conservator tank	1	16	60	1000	0.33	653			
1.5.8	Conservator tank	1	16	60	1000	1		1,960	1,960	1,960
1.6	Repairs									
1.6.1	Oil pumps	4	32	80	1000	1	11,240			
1.6.2	Oil pumps	4	32	80	1000	0.5		5,620		
1.6.3	Oil pumps	4	32	80	1000	0.25			2,810	2,810
1.6.4	Oil pump rebuild	4	40	80	10000	0.25	5,700			
1.6.5	Oil pump rebuild	4	40	80	10000	0.1		2,280		
1.6.6	Oil pump rebuild	4	40	80	10000	0.05			1,140	1,140
1.6.7	Fan motors	4	30	80	5000	0.25	3,650			
1.6.8	Fan motors	4	30	80	5000	.1		1,460		
1.6.9	Fan motors	4	30	80	5000	0.05			730	730

Table 7-2 (continued)
Hypothetical Example for Single Tank, Single Unit, 3-Phase Transformer

Item #	Activity Description	No. of Comp.	Labor Hours	Labor Cost ($)	Mat. Cost ($)	Frequency/ Year	Alt. A Existing Maintenance Program	Alternative B Partial Upgrade & Aggressive PM Program	Alternative C Refurbishment & Aggressive PM Program	Alternative D New Transformer & Aggressive PM Program
1.7										
1.7.1	Pump replacement w/ efficient with minimum 15 year bearing life (cost includes drain oil)	4	80	80		One time		90,000		
1.7.2	Fan motors	12	8	80		One time		8,000		
1.7.3	Bushings (cost includes drain oil)	6	160	80		One time		77,000		
1.8										
1.8.1	Repair old transformer on site	1	180	80		One time		95,000		
1.8.2	Remove old transformer (cost includes material & equipment)					One time			110,000	110,000
1.8.3	Repair old transformer at the factory (includes transportation)					One time			950,000	
1.8.4	Install old transformer					One time			1,500,000	
1.8.5	Install new transformer (cost includes transformer cost, material & equipment)	1	800	80		One time				5,300,000
2.1	Other									
2.1.1	Lost Power generation ($250,000 per day) (Note 1)					0.2	1,200,000			
2.1.2	Lost Power generation ($250,000 per day)					0.1		600,000		

Table 7-2 (continued)
Hypothetical Example for Single Tank, Single Unit, 3-Phase Transformer

Item #	Activity Description	No. of Comp.	Labor Hours	Labor Cost ($)	Mat. Cost ($)	Frequency/ Year	Alt. A Existing Maintenance Program	Alternative B Partial Upgrade & Aggressive PM Program	Alternative C Refurbishment & Aggressive PM Program	Alternative D New Transformer & Aggressive PM Program
2.1.3	Lost Power generation ($250,000 per day)					0.05			300,000	
2.1.4	Lost Power generation ($250,000 per day)					0.03				180,000
2.2	Regulatory Cost Per Year						25,000	10,000	4,000	2,000
	Total Recurring Cost						1,314,503	728,280	417,600	295,000
	Total One Time Cost						0.0	270,000	2,560,000	5,410,000

Note: A Lost Power Generation $250,000/day * 24 days (estimated replacement/repair time)*0.2=$1,200,000

8 GUIDANCE FOR ESTIMATING FUTURE FAILURE RATES

This section addresses a part of step number 18 of Figure 2-1b. Failure rates are a main driver of the LCM planning process.

General guidance for estimating SSC future failure rates can be found in Section 2.6 of the LCM Sourcebook Overview Report [1]. The following are some useful ideas for estimating failure rates in the large power transformer LCM planning studies.

- Table 6.2, Degradation Mechanisms, provides the estimated "Useful Life of Components." This data may be used to estimate the expected remaining life of the transformer components. If "in-kind" replacements are made, existing failure rates may be applied for the future.
- Plants that have a transformer performance trending program can extract transformer failure data and compute failure rates for the large transformers. Data can be plotted to determine the effects of aging and if the current PM programs are effective.
- Large transformer failures likely to result in a plant trip or a reduction in power are due to transmission system disturbances, LTC failure, transformer temperature escalation beyond design temperature limit, and transformer accessory failures.
- In addition to the above, more than 30% of the EPIX reported failures were due to human or maintenance errors. When evaluating and determining plant-specific failure rates, human errors and maintenance errors need to be included in the basis.
- Corrective work orders provide a means of reconstructing the transformer failures and to compute failure rates. The WO review should encompass at a minimum the last five years of data to generate meaningful results.
- Failure rate reductions can be achieved by replacing accessories such as oil pumps, motors, and fans that exhibit frequent breakdowns or failures. If the LCM plan considers such accessory replacements, future failure rate projections must consider the effect of replacement as discussed in the LCM Sourcebook Overview Report [1].
- When transformer accessories such as motors or pumps are replaced with a similar model from a different vendor, the failure rates may be different. A reasonable projection is to use the existing failure rate until a new failure rate can be determined (based on failure rate trending), unless the vendor has reliable data to support a different rate.
- The subject transformers although non-safety-related, provide power to safety-related equipment. Transformer failure may not trigger an immediate trip or scram, but will require entry into a Limited Condition of Operation (LCO). Various time limits are established from

a few hours to seven days based on the time estimated to repair the failed transformer or its accessories. Failure to repair or replace the failed equipment and return to operational status within the time limit requires steps for plant shutdown.

- Routine maintenance task tickets and corrective work orders provide failure cause information of transformer components and accessories. Such information can be used to establish the base case. Probabilistic Risk Assessment (PRA) based failure rates may be used in projecting future transformer failure rates and its components and accessories.
- The PRA based failure rates for transformers are likely expressed in demand failures (or reliability), if the transformer is in stand-by service. These values can be converted to failure rates, if the annual demands (actual and tests) are known. If the transformer is normally operating, its performance is likely modeled as availability or the inverse unavailability, expressed in hrs/hr of service. To convert this to a annual forced outage rate, multiply the value by 8760 (hours per year) to obtain the expected (probable) annual out-of-service rate to be used for lost power generation calculations.
- When the plant-specific PRA is used as a basis for the plant-specific system failure rates, verification of the basis for the PRA input should be considered.
- If plant-specific transformer failure rates are not readily available from plant databases, the plant-specific PRA may be a source of reliability values for use in LCM planning. See above method to convert reliability values (demand failures) to annual failure rate. Establishing a comprehensive transformer and accessory performance trending program is an important step in LCM planning.
- Transformer failure rates from Section 4.0 (Table 4.1) can be used in the absence of a performance trending program. If no plant specific failure data exists or is of questionable accuracy, it would be reasonable to assume an average industry failure rate (over the last 11 years) of about 0.10 per year as a starting point in the LCM analysis. The absence of transformer failures could be verified by reviewing the Trip/Scram reports for the plant. Transformers that are more than 20 years old (>50% of their design life) will experience a higher failure rate due to aging and the high end of the industry-wide failure rate would apply (0.15 per year).
- Table 6.2 provides the failure timing of the major components for transformers. This information can be used to project possible remaining life of a component or to plan for transformer replacement.

In summary, failure rate predictions for plant-specific transformer components are made using the above specific guidance and the generic guidance presented in Section 2.6 of the LCM sourcebook overview report. PRA and Maintenance Rule records may be an important source of information. The LCM planning process should be fairly complete with carefully defined specific activities for each of the LCM alternative plans. In this way, the influence of new or additional PM activities, implementation of replacements, and redesigns can be appropriately considered in estimating future failure rates for input to LCM economic evaluations.

9 PLANT-SPECIFIC GUIDANCE FOR ECONOMIC MODELING

This section addresses the cost prediction portion of step number 19 in the LCM planning flowchart (Figure 2-1b).

In this large transformer LCM sourcebook, generic cost data is presented below from the INPO data and should be corrected for the individual plants, given the variations in equipment types and sizes and plant-specific accounting practices.

Table 4.1 shows a total of 119 transformer failures in U.S. plants over a period of 10 years (1991 to 2001). With 104 operating plants, this averages to about 0.11 failures per year per plant, 40 of the events (or about 33.6%) caused a plant shutdown for an average of 9 days (for a 1000 MW plant this equates to 10 million dollars).

Therefore, for an individual plant, the potential annual cost in lost power production from a transformer failure based on the industry average (at $50 per megawatt hour) is:

0.11 x 0.336 x $ 10,000,000 = $ 400K

This value may be of use when considering implementation or corrective actions capable of reducing the failure probability.

When developing alternatives, it is best to formulate plans that are relatively simple and do not include massive changes at one time. A step-wise approach will provide simplicity and retain overview of the plan. For instance, a first step from the base case would be the conversion to a more effective preventive maintenance program for the transformers, including oil analysis, thermography, and failure trending. The additional costs and savings can then be determined for the remaining life of the plant and the impact on transformer failure reduction can be illustrated.

Although the initial cost for an aggressive PM program is high, reduction in failure rate of transformers and components will offset the cost as equipment and plant outages are reduced. Section 3.8 of the LCM Planning Sourcebooks Overview Report [1] contains a generic discussion and listing of the typical financial data to be collected and specified as input to the economic evaluations of alternative LCM plans.

10
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EXHIBIT 8

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IEEE Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformers

C57.140™

IEEE Power Engineering Society

Sponsored by the
Transformers Committee

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Abstract: This guide includes guidelines for the following: insulating oil maintenance and diagnostics, oil reclamation, testing methods for the determination of remaining insulation (paper) life, and upgrades of auxiliary equipment such as bushings, gauges, deenergized tap changers (DETCs), load tap changers (LTCs) (where applicable), and coil reclamping. The goal of this guide is to assist the user in extending the useful life of a transformer.
Keywords: evaluation, life extension, reconditioning, risk assessment

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Introduction

This introduction is not part of IEEE Std C57.140-2006, IEEE Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformers.

At the turn of the century, approximately one half of all transformers used in the electric utility industry reached their 30 yr design life. Because of today's economics, many of these transformers will be called upon to supply reliable service for an additional 20 yr to 30 yr. Any transformer owner intending to significantly extend the life should address three key areas: economics, inspection and diagnostics, and materials and design.

A comprehensive economic study should be carried out before the investment of significant resources. This study involves load forecasts, reserve margins, new capacity plans, cost-benefit analyses, operating costs, capital costs, and continued reliability and availability.

Once a financial decision to extend the transformer life is made, an inspection and diagnostic strategy should be determined. This evaluation should include the following: manufacturer, size, age, operating history, thermal load, electrical tests, maintenance history, and failure history.

New materials, major component replacement, and other design changes may also affect the life extension decision. The development of better core steel and better solid insulation has been ongoing for a number of years. The better operating efficiency of new materials may make life extension uneconomical.

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Table 1—Event tree

Component/ System	Subcomponent	Failure	Root Causes	Symptom	Tests and Condition Assessment Tools											
					Turns Ratio	Insulation Resistance	Winding Resistance	Exciting Current	FRA	Power Factor/ Capacitance	Oil DGA	Visual	Alarms	PD Monitoring	Fault Recorder	Infrared Scan
Bushing	Condenser	Insulation Breakdown	Overvoltage/Elevated Operating Temperatures	Increased Power Factor						X						
				Increased Capacitance						X						
			Material/Workmanship Defects	Increased Power Factor						X						
				Increased Capacitance						X						
	Oil	Loss of Oil	Gasket/Seal Failure/Vandalism	Loss of Oil								X				
		Oil Contamination	Gasket/Seal Failure/Vandalism	Moisture Intrusion						X	X					
	Corona Shields	Shields Not In Place	Workmanship	Gassing							X					
				PD							X			X		
Windings/ Conductors	Winding/Conductor	Turn-Turn Fault	Through Fault/Overvoltage/Design Flaw	Gassing	X		X				X					
				PD							X			X		
		Coil-Coil Fault	Through Fault/Overvoltage/Design Flaw	Gassing	X		X				X					
				Short-Circuit Current	X										X	
				PD							X			X		
		Coil-Ground Fault	Through Fault/Overvoltage/Design Flaw	Gassing	X	X				X	X					
				Short-Circuit Current	X										X	
				PD							X			X		
		Lead-Lead Fault	Through Fault/Overvoltage/Design Flaw	Gassing	X	X	X			X	X					
				Short-Circuit Current	X										X	
				PD							X			X		
		Lead-Ground Fault	Through Fault/Overvoltage/Design Flaw	Gassing	X						X					
				Short-Circuit Current	X										X	
				PD							X			X		
	Insulation	Insulation Breakdown	Through Fault/Overvoltage/Design Flaw	Gassing	X	X	X			X	X					
				Short-Circuit Current											X	
				PD							X			X		
			Material/Workmanship Defects or Deterioration with age,	Gassing	X	X	X			X	X					
				Short-Circuit Current											X	
				PD							X			X		
			Static Electrification	Intermittent DC Discharges							X			X		
Core	Core Steel	Lamination Insulation Breakdown	Material/Workmanship Defects	Gassing							X					
		Core Steel Joint Opening	Design/Workmanship Defects	Gassing							X					
	Insulation	Insulation Breakdown	Flux Heating/Structural Overstress	Elevated Temperatures												X
				Gassing							X					
		Core Ground	Contamination/Mechanical Insulation Damage/Thermal Insulation Damage	Gassing		X					X					
				PD		X					X			X		

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Table 1—Event tree *(continued)*

					Tests and Condition Assessment Tools											
Component/ System	**Subcomponent**	**Failure**	**Root Causes**	**Symptom**	**Turns Ratio**	**Insulation Resistance**	**Winding Resistance**	**Exciting Current**	**FRA**	**Power Factor/ Capacitance**	**Oil DGA**	**Visual**	**Alarms**	**PD Monitoring**	**Fault Recorder**	**Infred Scan**
Oil and Oil Preservation Systems	Oil	Moisture Intrusion	Contamination Introduced Gasket/Seal Failure	Reduced Dielectric Strength		X				X	X					
		Oxidation	Sludge	Elevated Temperatures												X
	Conservator	Bladder Failure	Processing Error	Reduced Oil Dieleetric Strength						X	X					
			Material or Workmanship Defects	Reduced Oil Dielectric Strength						X	X					
				Oil Level Gauge Error								X				
				Oil Inside Bladder								X				
	Piping	Incorrect Valve Position(s)	Human Error	Pressure Relief Action								X			X	
		Oil Containment Failure	Improper Painting/Improper Assembly/Gasket Failure	Oil Leaks								X				
			Material/Workmanship Defects	Oil Leaks								X				
Radiator/ Cooler	Pump	Motor Failure	Elevated Operating Temperatures/ Wearout	Loss of Oil Flow								X	X			
		Bearing Failure	Wearout/Design Defect	Noisy Operation, Oil Contamination							X	X				
		Loss of Power	Circuit Failure/Unreliable Power Supply	Loss of Supply Voltage									X			
	Fans	Motor Failure	Elevated Operating Temperatures/ Wearout	Loss of Oil Flow									X			
		Bearing Failure	Wearout/Design Defect	Noisy Operation, Oil Contamination							X	X				
		Loss of Power	Circuit Failure/Unreliable Power Supply	Loss of Supply Voltage									X			
	Radiator Plates	Weld Failure	Improper Welding/Materials	Oil Leaks								X				
		Rust/Corrosion	Defective or Poorly Maintained Paint System	Rust/Corrosion/Oil Leaks								X				
	Coolers/Tubesheets	Rust/Corrosion	Defective or Poorly Maintained Paint System	Rust/Corrosion/Oil Leaks								X				
	Cooler Case	Rust/Corrosion	Defective or Poorly Maintained Paint System	Rust/Corrosion								X				
Deenergized Tap Changer (DETC)	Contacts	Contact Burning/Arcing	Material/Workmanship Defects	Gassing							X					
	Drive Shaft	Loss of Control	Material/Workmanship Defects	Inability to Change Taps								X				

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Table 1—Event tree *(continued)*

Component/ System	Subcomponent	Failure	Root Causes	Symptom	Tests and Condition Assessment Tools											
					Turns Ratio	Insulation Resistance	Winding Resistance	Exciting Current	FRA	Power Factor/ Capacitance	Oil DGA	Visual	Alarms	PD Monitoring	Fault Recorder	Infred Scan
Load Tap Changer (LTC)	Contacts	Contact Burning/Arcing	Material/Workmanship Defects	Gassing							X					
	Drive Shaft	Loss of Control	Material/Workmanship Defects	Inability to Change Taps								X				
	Control Circuitry	Loss of Control	Relay/Component Failure	Inability to Control								X	X			
	Isolation Board	Cracks/Oil Containment Failure	Processing Error	Gas in Main Tank Oil							X					
			Material or Workmanship Defects	Gas in Main Tank Oil							X					
	Gaskets	Loss of Oil Containment	Material or Workmanship Defects, or Aging	Oil Leaks							X					
Relay Protection System	Relay Components	False Trip/Alarm	Design/Material/Workmanship	Relay/Alarm Action									X			
	Circuitry/Plugs/Terminals	False Trip/Alarm	Design/Material/Workmanship	Relay/Alarm Action									X			
Tank	Gaskets	Loss of Oil Containment	Material or Workmanship Defects, or Aging	Oil Leaks							X					
	Piping	Loss of Oil Containment	Material or Workmanship Defects	Oil Leaks							X					
	Structural Steel	Structural Failure	Design/Material/Workmanship	Tank/Structure Distortion								X				
		Flux Heating	Design/Material Defect	Elevated Tank Temperatures												X
				Gassing							X					

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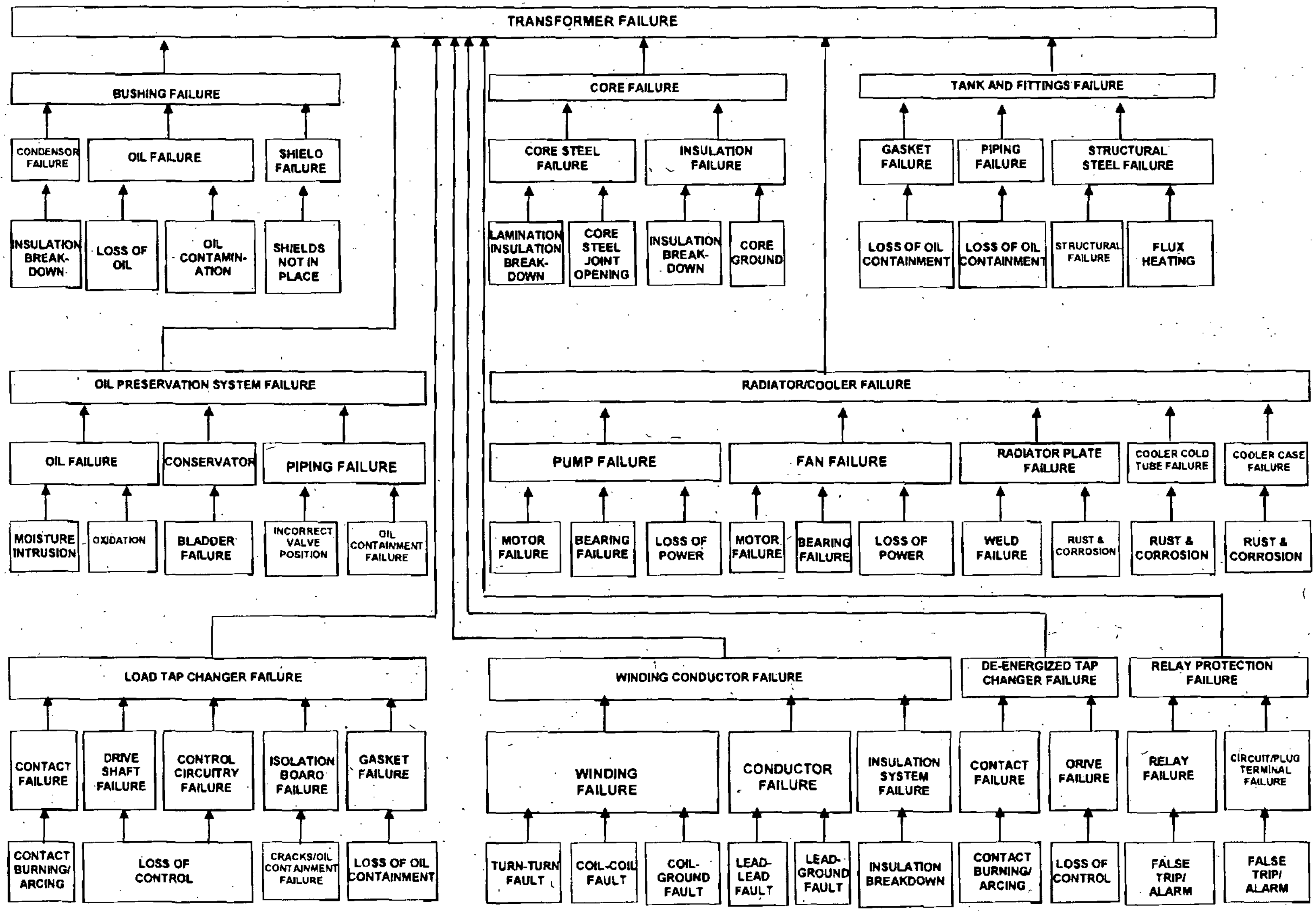

Figure 1—Transformer fault tree

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5. Diagnostic tests

This clause describes modern diagnostic tests and inspection techniques that are conducted in the field on electrical equipment. Interpretive discussions are also included to provide guidance on acceptance criteria. These activities may help identify existing weaknesses or faults and also give some indication of expected service reliability and remaining life. No single electrical test can assure continued operation. Only the careful recording and plotting of the test results makes it possible to get the full information out of a test and to compare the values with those of previously conducted tests. It should be noted that several assessments might have to be interpreted together to diagnose a problem. The manufacturer's acceptance criteria should also be consulted because it may take precedence over the criteria in this guide.

CAUTION

Bushing current transformers should always be shorted and grounded whenever testing is done on a transformer.

5.1. Dissolved gas analysis (DGA)

Significant information regarding the condition of the insulation system of a transformer can be obtained from oil testing and correct interpretation of the oil analysis. It is beyond the scope of this guide to provide detailed technical information on all oil analysis and testing; however, it is recommended that the reader refer to the bibliography for references on oil testing and analysis (specifically, Chendong [B8], Dominelli et al. [B11], Horning et al. [B16], Pruente [B34], Vogel et al. [B44], and Wilson et al. [B45]).

DGA using oil has proven to be a valuable and reliable diagnostic technique for the detection of incipient fault conditions within liquid-immersed transformers by detecting certain key gases. DGA has been widely used throughout the industry as the primary diagnostic tool for transformer maintenance, and it is of major importance in a transformer owner's loss prevention program.

Data have been acquired from the analysis of samples from electrical equipment in the factory, laboratory, and field installations over the years. A large body of information relating certain fault conditions to the various gases that can be detected and easily quantified by gas chromatography has been developed. The gases that are generally measured and their significance are shown in Table 2, based on IEEE Std C57.104. Methods for interpreting fault conditions associated with various gas concentration levels and combinations of these gases are also provided in IEEE Std C57.104.

Table 2—Gases typically found in transformer insulating liquid under fault conditions

Gas	Chemical formula	Predominant source
Nitrogen	N_2	Inert gas blanket, atmosphere
Oxygen	O_2	Atmosphere
Hydrogen[a]	H_2	PD, overheated oil adjacent to hot metal (core or windings)
Carbon dioxide	CO_2	Overheated cellulose, air pollution Natural degradation product of cellulose aging which may be accelerated by heat
Carbon monoxide[a]	CO	Overheated cellulose, air pollution Natural degradation product of cellulose aging which may be accelerated by heat
Methane[a]	CH_4	Overheated oil adjacent to hot metal, or PD

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Table 2—Gases typically found in transformer insulating liquid under fault conditions *(continued)*

Gas	Chemical formula	Predominant source
Ethane[a]	C_2H_6	Overheated oil adjacent to hot metal
Ethylene[a]	C_2H_4	Overheated oil adjacent to hot metal
Acetylene[a]	C_2H_2	Arcing in oil

[a] Denotes combustible gas. Overheating can be caused both by high temperatures and by unusual or abnormal electrical stress.

Laboratory-based DGA programs are typieally eondueted on a periodie basis dietated by the applieation or transformer type. Some problems with rapidly inereasing gas levels may go undeteeted between normal laboratory test intervals. Installation of continuous gas-in-oil monitors may detect the start of incipient failure eonditions that might allow confirmation of the presenee of a suspected fault through laboratory DGA testing. This early warning may allow the user to plan necessary steps required to identify the fault and implement eorrective aetions where possible. Present technology exists that can determine gas type, eoneentration, trending, and production rates of generated gases. The rate of ehange of gases dissolved in oil is a valuable diagnostie tool in terms of determining the severity of the developing fault. A conventional unscheduled gas-in-oil analysis is typically performed after an alarm condition has been reported. The application of on-line dissolved gas monitoring may considerably reduce the risk of missing detection or of prolonged delay in detecting fault initialization due to long on-site sampling intervals (see IEEE PC57.143).

Laboratory-based sampling and analysis that is frequent enough to sufficiently obtain real-time feedback becomes impractical and too expensive. For eritical transformers, on-line gas-in-oil monitors can provide timely and continuous information in a manner that permits load adjustments to prevent excessive gassing from thermal-type faults. This approach can keep a transformer operating for many months while ensuring safety limits are observed.

The review of all of the DGA history for a unit is of high importance for determining the operating condition of the transformer and needs to be done when considering life extension options for the unit.

5.2. Oil quality assessment (physical tests)

Over years of operation, insulating fluid quality typically deteriorates significantly. An important part of the life extension of a transformer is the restoration of the transformer insulating fluid quality. The insulating fluid quality has implications on virtually all operational characteristics (e.g., dielectric performance, aging rate, thermal performance). Depending on the condition of the insulating fluid, it may be justified to reprocess, reclaim, or replace it.

For the purpose of this guide, the diagnostic tests for insulating fluid quality described in IEEE Std 62 and IEEE Std C57.106 are highly recommended.

It is important, as part of the condition assessment of the transformer, to determine the quality of the insulating fluid. The results of the insulating fluid quality assessment will determine the need for insulating fluid reconditioning, reclamation, or replacement.

Particular attention should be paid to the moisture in the insulating fluid. The measurement of moisture in insulating fluid is a routine test (in addition to other physical characteristics of the insulating fluid) performed in the laboratory on a sample taken from the transformer. Moisture in the transformer reduces the insulation strength by decreasing the dielectric strength of the transformer's insulation system. The combination of moisture, heat, and oxygen is the key factor that affects the rate of cellulose degradation.

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Moisture level in the insulating fluid depends on the operating condition of the transformer (e.g., winding moisture content and temperature) as well as the type and condition of the fluid. High fluid acidity and high particle levels increase the capacity of the fluid to absorb moisture. Usually this situation can be corrected by fluid reclamation or, for more severe cases, by fluid replacement.

Higher levels of moisture may be more acceptable in fluids such as silicone or vegetable oil (esters) than in mineral oil due to differences in moisture saturation values. Although the use of these types of fluids is relatively recent and not yet common, such differences should be considered in the interpretation of the implications of moisture content.

Assessment of the level of moisture in the paper should be made, preferably by on-line monitoring of the insulating fluid moisture level, (see Vogel et al. [B44]) to complement the oil assessment. Reduction of moisture in insulating fluid will not necessarily reduce moisture content of the solid insulation sufficiently (see Clause 7).

5.3. Furan analysis

One of the latest insulating fluid test methods to help determine the condition of the insulation system is a test of furanic compounds. This method will help determine the overall degradation of the cellulose within the apparatus being sampled. Methods or guides for interpretation of the results of this test have not been universally adopted. However, much research has been done, and some guidelines exist (see Bouchard and Lapointe [B6], Shroff and Stannett [B42], Chendong [B8], Burton et al. [B7], Dominelli et al. [B11], and Horning et al. [B16]).

Furanic compounds are a family of molecules based on a furan ring structure. The furanic compounds in Figure 2 are generated in various amounts by the degradation of cellulose (paper) and are, therefore, a paper degradation marker.

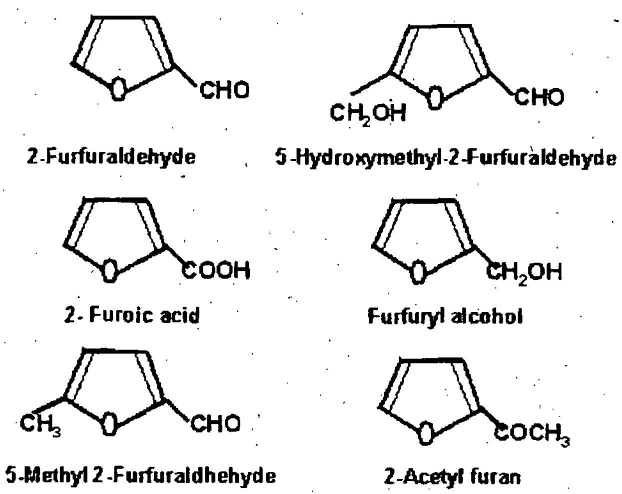

Figure 2—Furanic compound family

The most stable of these compounds is 2-furfuraldehyde, or 2-FAL, and in most routine analysis, this component is the only one measured. In transformers with paper insulation, furanic compounds are intermediate degradation products generated in trace quantities. These quantities are absorbed in the paper-oil system. Oil degradation would not produce furanic compounds. Thermal degradation of paper insulation could be monitored by furan analysis, especially when due to overheating conditions.

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Attempts have been made to relate the furanic content (2-FAL) of oil to the degree of polymerization (DP) of paper. When the DP test reveals a value of 200 or less, the paper is considered to have lost almost all mechanical strength, and the transformer has reached its end of life (see Shkolonik et al. [B40]). A 2-FAL limit of 100 µg/L (ppb) has been deduced from analysis of thousands of oil samples as a "norm." The corresponding DP would be no lower than 400, which implies acceptable mechanical strength for the paper. Excessive furanic content in oil is indicative of pyrolysis of paper, which can also be inferred from excessive carbon monoxide generation.

Test standards for measuring furanic content in insulating fluid include ASTM D5387.

It must be pointed out that changing the oil would take out most of the furanic content in a transformer; hence the furanic content measured thereafter cannot be used for remaining life estimations using DP correlations.

It should also be understood that this test method is an indirect indication of the cellulose condition. Its precision is somewhat less than the DP measurement described in 5.8.

5.4. Power factor

The dielectric loss in any insulation system is the power dissipated by the insulation when an ac voltage is applied. (All electrical insulation has a measurable quantity of dielectric loss, regardless of condition. Good insulation usually has a very low loss.) Power factor testing consists of applying an ac voltage (not to exceed the rated voltage of the equipment being tested) and measuring the leakage current across and through the insulation system. Because an insulation system can be represented as a resistor and a capacitor in parallel, the power factor of the insulation can be defined as the result of leakage current (I_R) divided by the total current (I_T). The leakage current, and proportionally the power factor, will increase as the insulation system deteriorates.

The power factor test and the dissipation factor test are two similar methods of measuring the dielectric loss of an insulation system. The two terms *power factor* and *dissipation factor* are often used interchangeably even though they have slightly different mathematical characteristics. Power factor is a dimensionless ratio of the resistive current to total current flowing through the insulation. Dissipation factor (also known as tan delta test) is a dimensionless ratio of the resistive current to the reactive current flowing through the insulation. By convention, these factors are usually expressed as a percentage, which is one hundred times the value obtained from the basic calculation.

Because most field testing is done in energized stations, it is important that the test equipment be properly shielded to prevent electrostatic interference from influencing the test results. Most test equipment manufacturers are familiar with the problem and have a method of eliminating or canceling the interference. If unusual readings are encountered, ensure that the equipment is working properly before proceeding. If the tests show an increasing trend in the power factor, further investigation is warranted to determine the cause and possibly repairs before further degradation occurs. Determination of the cause of increased power factor is usually made by analyzing all of the available test data to find the problem.

If the high power factor readings are caused by contamination in the oil, there will be corresponding results in the oil analysis. Increased oil power factor may be the result of moisture or polar and ionic compounds in the oil. This contamination may also reduce the dielectric strength of the oil. A power factor test can also be run on the oil itself.

Moisture in the insulation system is another cause of increasing power factor. The moisture level of the oil will help determine whether this situation could be the source of the problem. If the insulation is determined to be wet, a procedure for drying the unit can be implemented. Such procedures include filtering (on or off line), vacuum processing, or untanking and drying at a transformer repair facility.

Internal inspections and repairs are possible in the field, but much of the insulation is inaccessible without untanking the transformer. If field repairs are made, care should be used to ensure that the replacement

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materials are properly processed, compatible with the remainder of the system being repaired, and capable of withstanding the expected operating conditions.

Bushings are often a source of high power factor readings. These parts can usually be tested in place and, as with the transformer, previous data are used to evaluate the results. If it is determined that a bushing or bushings are the cause of the problem, they can be replaced or repaired.

The main capacitance, C1, of a bushing is the capacitance between the high-voltage conductor and the voltage tap (115 kV bushings and above) or the test tap (69 kV bushings and below). The capacitance C2 of a capacitance-graded bushing is the capacitance between the voltage tap (115 kV and above) or the test tap (69 kV and below) and the mounting flange (ground).

— Capacitance C1 is measured during the power factor test of the bushings and must be very close to the value shown on the nameplate of the bushing (tolerance ± 5%).

— Capacitance C2 is measured during the power factor test and is used as a benchmark, especially when measured during the initial installation of a brand new bushing never exposed to moisture or humidity. Deviation of the C2 measurement from the nameplate on future power factor tests could also be used to determine whether there has been moisture intrusion in the potential tap or near the flange. However, this result does not necessarily determine the internal condition of the bushing core.

5.5. Frequency response analysis (FRA)

FRA is a diagnostic test that is used to help identify possible deformations and movements in the transformer's core and coil assembly and other internal faults. FRA consists of measuring the impedance of transformer windings over a wide range of frequencies and comparing the results of these measurements with a reference set, i.e., previous results or results from a similar transformer. The basis of the FRA technique is that the impedance of the transformer (i.e., resistance, inductance, and capacitance) is related to the construction and geometry of the windings. Deformations and movements have an effect on both inductance and capacitance that may be reflected in the resulting frequency response.

Measuring the frequency response of a winding within a transformer will provide a "fingerprint" for that winding or transformer. The analysis requires measurement of both input and output signals. The response is the ratio of the two signals. There are basically two methods: impulse method and sweep frequency method. Both methods are currently used within the industry.

With regard to the reference set of measurements, the reference measurement must have been made previously on the same winding in the same transformer. There is no such thing as an identical transformer. Therefore, measurements made on similar transformers should be used with extreme caution. The transformer manufacturer may be able to provide invaluable insight to the user under these circumstances.

If there are discrepancies between the original tests and the latest test results, further investigation and testing (e.g., excitation test) are a logical next step.

5.6. Partial discharge (PD) detection

PD occurs in an insulation system when a local breakdown of the insulation medium causes a redistribution of charge within the system. PD generates low-amplitude voltage and current pulses that are within radio range of frequency. Several techniques are available to detect and measure these signals in transformers. Two techniques consist of direct electrical measurements, and results are measured in microvolts of radio frequency energy or in picocoulombs. The other method consists of acoustical measurements with an ultrasonic transducer. It is possible to locate an active discharge in the transformer by comparing the signals from acoustic and from electrical detection.

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5.6.1. Electrical measurements

Because PD is an electrical phenomenon, electrical measurements allow for the most direct and quantifiable data. PD measurements in the field can be accomplished using at least two different methods. The first method is the field-induced test, which is similar to factory testing, where a portable high-frequency generator system is used to excite the transformer. The second method involves exciting the transformer at the power frequency either from the utility grid or from an isolated generator.

The field-induced test for older transformers is typically done at voltages somewhat less than the full induced voltage test levels as specified in IEEE Std C57.12.00. Typical tests are done at 75% to 85% of the IEEE test levels for a duration of anywhere from 30 min to 60 min. The voltage level and test duration are based on assessment of the age and condition of the bulk insulation and bushings or other components and the capacity of the test generator.

PD activity may be measured using either the radio influence voltage (RIV) method or the apparent charge method. Each method has its own relative advantages and disadvantages. The RIV method is less affected by external noise from the power system, but may be affected by radio stations. It also is generally less sensitive to discharges deep within the transformer windings. (The RIV of equipment was historically measured to determine the influence of energized equipment on radio broadcasting; hence the name RIV.) Typically, if the PD magnitudes are less than either 100 μV or 500 pC, the transformer is considered acceptable. If the levels are above 500 μV or 1000 pC, then the transformer may be suspect. For values in between, the results are questionable, and further testing may be needed to more precisely characterize the risk.

Advanced PD measurement methods are available that can effectively filter out external noise influences to selectively measure the PD activity in the windings. These methods involve narrow band measurements at certain resonant frequencies of the transformer to amplify the PDs and reduce the background noise. With this type of measurement, a transformer may be tested with excitation from the power grid. In other instances, the natural attenuation of PD between windings can be used to isolate the high-voltage winding while exciting a low-voltage or tertiary winding.

Another advanced measuring method involves the measurement of a PD pattern based on a three-dimensional plot of the PD magnitude, phase angle of the pulses, and the number of pulses. Different types of insulation defects produce different but recognizable patterns, and the PD test result can be compared to a library of test results to make a judgment about the cause of the PD. In addition, the test can often establish a relative location of the PD within the transformer by PD pulse shape characteristic and time displacement between the bushings.

One of the primary means of detecting PD is to measure the small voltage pulse, or current pulse, that accompanies every discharge. In a typical transformer, there may be thousands of PDs per second; thus, there may be thousands of pulses detected every second. The voltage pulse can be detected by means of high-voltage capacitors, which are normally connected to each phase terminal. A bushing test tap or an existing surge capacitor can be used, or a small capacitor can be attached to the terminal. The capacitor has a high impedance to the power frequency, but appears as a low impedance to the high-frequency PD voltage pulses. Special circuits are used to convert the pulse signals from an analog form to a digital form. Some of these special meters include spectrum analyzers, quasi-peak pulse meters, and RIV meters. One of the most common approaches is to use pulse height analysis. The analyzer measures the number of pulses and magnitude of each individual pulse and plots them. There are also pulse phase analyzers, which digitally record where the PD pulses occur with respect to the power frequency. Interpretation of test results requires some experience with PD tests and with the type of device being tested. Comparing previous measurements on the same piece of apparatus (including factory tests) will achieve the best results for this type of test.

PDs caused by static electrification are typically intermittent dc discharges associated with the buildup of static charge resulting from forced-oil flow past cellulose surfaces. Such discharges are totally different from PD associated with ac voltage and must be detected differently. There have been many instances where such discharges were detected audibly as pinging or banging inside the transformer at intervals ranging from a few seconds to many minutes.

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5.6.2. Acoustic

The acoustic method of detecting PD offers good sensitivity to many types of PD sources and, in some situations, permits the site of the source to be located inside the transformer. The acoustic technique has the advantage that, when properly applied, it can be used on energized equipment and it is not susceptible to interference from outside sources. Acoustic signals are measured using ultrasonic transducers that are coupled to the outside wall of the transformer tank. In addition to the transducers, the other test equipment components are an amplifier and a display device. Self-contained, portable acoustic detectors are available for quick go-no-go field test programs. However, locating the PD source requires specialized measurements and custom-designed software and equipment.

5.7. Infrared inspection

Thermography is a noncontact means of identifying thermal anomalies relating to electrical and mechanical components that are exhibiting an excessive heat loss. This situation may be indicative of poor connections, excessive stray flux, blocked cooling circuits, or other problems that have the potential for causing eventual failure of the transformer. An infrared thermal scanning camera is used to record thermal images for subsequent analysis and identification of corrective maintenance action. The self-emitted radiation in the infrared portion of the electromagnetic spectrum is measured at the target surface and converted to electrical signals.

5.7.1. Noncontact thermal measurement

The component to be measured should be at normal operating temperature. Because heating varies directly with the square of the current, component loading will directly affect the thermographic image. The current level should at least be 40% of rated full load. If measurement is recorded when the equipment is not at full load, the maximum temperature rise can be estimated by Equation (3) and Equation (4).

For cooling by natural convection and radiation

$$T_{rise\,max} = T_{rise\,meas}\left(\frac{I_{rated}}{I_{meas}}\right)^{1.67} \tag{3}$$

For cooling by forced convection and radiation

$$T_{rise\,max} = T_{rise\,meas}\left(\frac{I_{rated}}{I_{meas}}\right)^{2} \tag{4}$$

where

Trisemax	is maximum temperature rise
Trise meas	is measured temperature rise
Irated	is rated current
Imeas	is measured current

How a surface appears in the visible spectrum is the same way the surfaces will appear in infrared. Temperature readings should be taken from target surfaces that are dull in the visible spectrum. When focusing on the target, get close enough so the target occupies a sizable section of the viewer screen. Look at the target face on, and move around to eliminate reflections.

Most thermal scans of equipment in metal enclosures will not give good readings unless the heat is of a high enough intensity to heat the enclosure. Therefore, panel doors and cabinets should be opened or panels removed, as necessary, to obtain good thermal scans.

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5.7.2. Maintenance scanning

Thermographic scans are usually performed semi-annually or annually. The ambient temperature, transformer winding and top oil temperature (instantaneous and maximum), and load information should be recorded. Establish a baseline for the component under normal load and operating conditions to facilitate identification of abnormalities. A comparison of phases in a three-phase system will indicate a uniform temperature pattern for balanced load and a nonuniform pattern for an unbalanced load. An unbalanced load can be distinguished from an anomaly, as the temperature is relatively constant along the component when component size and mass are the same. The manufacturer's literature should be checked to verify upper limits for actual temperature.

5.7.2.1. Transformer main tank

Determine normal operating temperature of the transformer tank, examine all sides of the enclosure, and record any temperature rise greater than or equal to 10 °C. In addition, similar measurements and criteria should be used for generator step-up transformers in the area where they are connected to the generator bus duct. Improper bus connections or deterioration of connections over the service life can result in excessive heating in the vicinity of the interconnection and the transformer tank.

5.7.2.2. Bushings

Determine the normal operating temperature, and document any temperature rise greater than or equal to 10 °C.

5.7.2.3. Tap changer

Record the tap position and tap changer counter, examine the tap changer, and record the temperature differential relative to the main tank. The tap changer should never be hotter than the main tank; any temperature rise may be an indication of a problem.

5.7.2.4. Control cabinet

Examine all connections and components. An understanding of control component functions is necessary as high temperatures on some components may be normal operating temperatures. Record any temperature greater than or equal to 10 °C above normal.

5.7.2.5. Overhead

For connections and other ancillary equipment, determine the normal operating temperature, and document any temperature rise greater than or equal to 10 °C.

5.7.3. Temperature rise

An acceptable maximum surface temperature rise is really dependent upon the environment of the equipment, severity of duty, significance of the equipment to the operating system, and equipment type. Knowledge of possible sources of measurement error (such as surface emissivity and solar reflections) is required for accurate readings and interpretation. Maintenance and operating personnel who are most familiar with the equipment should have the responsibility for judging the seriousness of an abnormal condition. Table 3 presents guidelines to use in the analysis.

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Table 3—Suggested temperature rise recommendations

Temperature rise above local ambient [a] (°C)	Action
0–10	Take no action.
10–25	Record and plan to reinvestigate within 3 to 6 mo.
25–70	Schedule an investigation and/or possible repair.
Above 70	Investigate immediately.

[a] Local ambient refers to immediate surrounding area. For example, the overall transformer tank temperature will be at least as hot as the top oil (40 °C to 60 °C above air temperature) without there being a problem. However, a spot on the tank that is 25 °C hotter than the surrounding tank area deserves further investigation.

5.8. Degree of polymerization (DP)

DP testing is used as a precise measure of the degradation of the paper insulation used in transformers, cables, and capacitors. Cellulose (i.e., the main constituent of paper and wood) is a large linear polymeric molecule constituted of several hundreds of glucose units. DP is the average number of glucose molecules making the cellulose chains. The DP value decreases with time as the cellulose molecules break and fragment. The rate of deterioration is very much temperature dependent.

It has been shown that the DP method provides a direct correlation between tensile strength and the DP result. The DP values range from an average value for new paper of about 1200 (i.e., on average, each cellulose chain contains 1200 glucose units) down to values for aged paper as low as 100. At a DP value of 200, a direct correlation has been shown to agree with paper that has lost approximately 70% of the original tensile strength. At this point, the paper becomes brittle, and the transformer can be deemed to be at the end of its useful life due to its loss of tensile strength (see Shroff and Stannett [B42]).

The test method that should be specified for determining the DP is ASTM D4243. An equivalent test method is IEC 60450.

The paper used in electrical equipment is assumed to age at a more rapid rate where the temperature of the paper and exposure to oxygen are the highest. In order to collect samples for DP tests, the paper should be collected from locations that have the most rapidly aging paper.

Once a transformer is manufactured, the paper with the highest probability of becoming weakened is usually in locations that cannot be easily accessed without risk of damaging the transformer. As a result, collecting the paper samples from a transformer may jeopardize the reliability of the transformer. For in-service equipment, taking samples must be limited to areas that, after repair, will result in a negligible increase in the probability of failure as a result of the paper sampling. Locations are selected based on judgment, but should usually be in the upper part of the transformer where top oil temperatures are the highest. A coil lead or a crossover connection could be such a location.

Collection of samples that are directly in contact with the conductor is important. If the transformer oil has been exposed to air, the outer layer of the paper should also be tested. To obtain a sample of paper in contact with the conductor often requires the removal of a considerable amount of insulating material. It is important that the insulation be carefully removed and the location and layer from which the paper was removed be documented. The repair of the insulation system requires great care. For example, paper tapes must be properly applied to replicate the previous insulation. Often paper tapes should be pre-impregnated with clean dry oil. The concept that "more paper is better" is a poor idea as excessive paper can cause hot spots by restricting the cooling of the conductor. It is recommended that properly trained personnel repair disturbed sections of the insulation system.

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If a transformer has failed and duplicate transformers exist, a good opportunity is presented for collecting samples from the failed unit that may be representative of identical units, particularly when the loading conditions have been the same. Such conditions exist for many generator step-up transformers. In these cases, the best locations for samples will be in areas of the windings presumed to be the hottest. For core-form transformers, this location will be near the top of the coils. For shell-form transformers, this location will be directly over the top of the core were the oil flow is the least.

Unfortunately for most transformers that are in service, the results of DP tests will result only in values that may not be representative of insulation that is in a higher state of deterioration. If these samples are below a DP of 300, the transformer may be at the end of its life.

Collecting the paper samples is an important process, and the following guidelines and Table 4 are presented to help ensure that the samples are collected and identified properly for laboratory analysis using ASTM D4243 or IEC 60450.

For routine testing,

— The minimum weight of oil-impregnated paper with excess oil removed is 300 mg.

— The minimum weight of non-oil-impregnated paper is 175 mg.

Table 4—Dimensions of paper needed

Thickness [in (mm)]	Area [in^2 (cm^2)]
0.003 (0.08)	6 (39)
0.005 (0.13)	3.5 (23)
0.010 (0.25)	2 (13)

For samples from failed transformers, a quick means for acquiring samples is to cut about six inches of the conductor out of the coil and wrapped insulation. Wrap the sample in plastic or place in a plastic bag, and identify the source and location.

The aging of the solid insulation is not uniform; therefore, the more paper samples tested, the better in order to understand the spatial distribution of relative aging of the solid insulation. Darker areas of insulation are an indication of advanced aging and should be candidates for testing. It is best to collect as many samples as possible and then test as many as needed to obtain the desired information.

Figure 3 is an example of the information that should be provided with the samples. Samples collected from different locations should be separated and clearly identified so that analysis of the results will be logical. Samples should be protected from the environment. The use of sealed plastic bags is a method of separating samples.

The testing facility should be consulted to discuss the different types of testing available, the accuracy of the different test methods, and associated sample requirements.

NOTE—Insulation cannot be varnished or impregnated with any material that will not be readily removed by rinsing with solvent. If the insulation is impregnated with anything other than the insulating liquid used in the transformer, it is unlikely that the DP measurement can be made.[9]

[9] Notes in text, tables, and figures are given for information only and do not contain requirements needed to implement this guide

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SAMPLE IDENTIFICATION

Note: Need to specify that test must be conducted in accordance with ASTM D4243.

TRANSFORMER NAMEPLATE

Manufacturer: Serial Number:

MVA: kV: Age:

Preservation System: Cooling System:

Type of Transformer: Transmission _____ Distribution ____ Generation ____

Loading History:

Load Level, Percent of Top Nameplate Rating (%)	Estimated Percent Time at Load Level (%)
<50	
50–75	
>75	
	=100

Comments:

Transformer testing history available: Yes ___ No ___
(If yes, please include results with sample, for example, power factor tests).

Cellulose Location *(see sampling)*:

Type of Paper *(for example, kraft, thermally upgraded kraft, creped, if known)*:

Insulating Oil Type:

Testing history and oil makeup or changeout records available: Yes ___ No ___
(If yes, please include results with sample.)

Figure 3—DP sample information

5.9. Vibration and noise

The human ear is a valuable tool in assessing equipment condition. However, the use of noise is subjective. Site checks are, therefore, best carried out with regular visits by the same qualified personnel. They can become accustomed to the usual sounds heard so that any new or unusual sounds or noises may be obvious to them.

New sounds can usually be located as coming from the tank, pumps, fans, or other components attached to the tank. Certain audible sounds are readily identified, but in some instances, the levels of sound, their tone, and direction may often be more apparent than real and are then difficult to locate and identify. However, any new or changed sound level is worth investigating.

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5.9.1. Internal noise

Increased levels of sound emanating from the tank could result because windings have become loose due to shrinkage or short-circuit movement. The sound due to such changes would generally have a tonal frequency of twice the operating system frequency. This change in sound could also be the result of loose leakage-flux rejecters or collectors. Abnormal overloads could also increase the level of sound or the tonal content emitted, both from normal winding vibration and leakage-flux collector saturation effects.

Damaged or loose cores could contribute to modified sound characteristics, as could any changes to the mechanical clamping or anchorage of the "active part" structure. Overvoltage and/or underfrequency will cause excessive flux and hence possible saturation of the core. This situation would result in higher sound levels and changing tonal composition. Superposition of dc on the exciting current can cause much higher sound levels as well as extra tonal harmonics.

Broken leads and/or their supports can be responsible for a change in sound levels and tones, especially if the natural frequency of these structures is close to a harmonic of the system power frequency.

5.9.2. External noise

Broken or loose external components can cause modified sound characteristics. Valve wheels and handles can become loose and vibrate when their retaining nuts become unlocked. Cabinet or other component antivibration mounts can fail and allow the component to rattle in sympathy with the normal transformer tank vibration.

Fans and pumps should be manually energized to ensure proper operation. Any significant noises (e.g., grinding, rubbing, scraping) should be noted and investigated further.

LTC motors may start to make different sounds if their bearings wear or if their windings become damaged. Also, if contacts become worn, different sounds may be noticed during the tap change operation.

6. Condition assessment and reconditioning

In order for a transformer to continue in reliable service for an extended period, every effort should be made (economically and operationally) either to regain the relevant original performance characteristics or to modify the loading and/or its application duty as appropriate. It is technically feasible to restore many of the factors that directly affect the long-term reliability.

After completion of the risk assessment and thorough diagnostic testing, the owner may have been able to reduce to a more manageable number the transformers that are candidates for condition assessment. Condition assessment includes both nonintrusive and intrusive evaluations. Obviously, the intrusive or internal evaluation is the most costly, most time consuming, and highest risk procedure. An internal evaluation may also be risky, depending on the age and condition of a transformer. The decision to perform this assessment must not be taken lightly. These inspections require great care and knowledge of transformer construction.

Although the condition assessment is considered an inspection, some components may be considered for upgrading or replacement at this time. Refurbishment or replacement of these components might arguably be considered as a comprehensive maintenance exercise, which may not contribute directly to the life extension of a transformer. Nevertheless, new or refurbished components could increase versatility and reliability, and they should be considered at this time because there is an opportunity to do so while the transformer is out of service.

The intrusive inspections and the transformer components are addressed in 6.1 through 6.8.

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EXHIBIT 9

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Aging Management Guideline for Commercial Nuclear Power Plants – Power and Distribution Transformers

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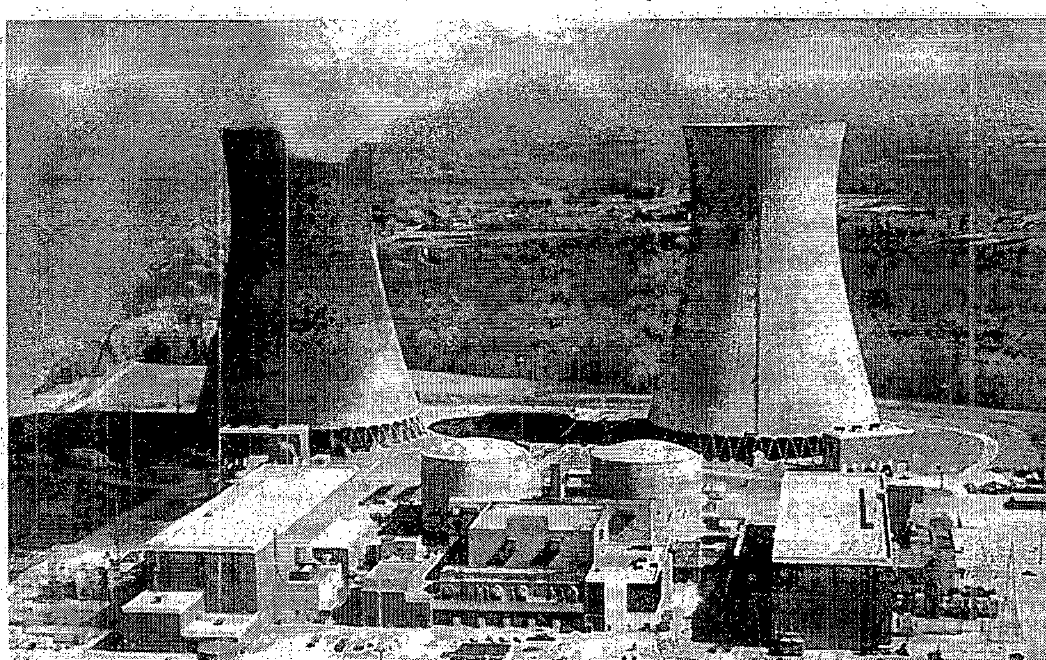

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AGING MANAGEMENT GUIDELINE FOR COMMERCIAL NUCLEAR POWER PLANTS- POWER AND DISTRIBUTION TRANSFORMERS

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Abstract

This Aging Management Guideline (AMG) provides recommended methods for effective detection and mitigation of age-related degradation mechanisms in power and distribution transformers important to license renewal in commercial nuclear power plants. The intent of this AMG to assist plant maintenance and operations personnel in maximizing the safe, useful life of these components. It also supports the documentation of effective aging management programs required under the License Renewal Rule 10 CFR Part 54. This AMG is presented in a manner which allows personnel responsible for performance analysis and maintenance to compare their plant-specific aging mechanisms (expected or already experienced) and aging management program activities to the more generic results and recommendations presented herein.

Acknowledgments

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AGING MANAGEMENT GUIDELINE FOR POWER AND DISTRIBUTION TRANSFORMERS

1. EXECUTIVE SUMMARY

1.1 Purpose and Objectives

Continued operation of nuclear power plants for periods that extend beyond the original 40-year license period may be a desirable option for many U.S. nuclear plant operators. To allow operation of the plant to continue beyond the original licensing period, utilities must show that the aging of components important to license renewal has been managed such that these components will not degrade to the extent that they are incapable of supporting required functions. Therefore, to allow operation during a license renewal period, operators of nuclear power plants must manage the aging of components so that proper function is assured.

The purpose of this Aging Management Guideline (AMG) is to provide guidance for the effective management of aging of power and distribution transformers (subsequently referred to as transformers) used in safety-related and non-safety-related applications in commercial nuclear power plants. An effective aging management program will ensure that these transformers will continue to perform their function or will not prevent the performance of a required function during the current and license renewal terms.

The objective of this AMG is to provide an analysis of the potential aging mechanisms for power and distribution transformers and to provide acceptable guidelines for developing aging management programs for controlling significant aging mechanisms. Use of this guidance will provide nuclear plant operators with a basis for verifying that an effective program for managing age-related degradation of transformers is in place.

1.2 Scope

Power and distribution transformers are used in commercial nuclear plants to connect the main generator to the high-voltage transmission system, and to connect offsite sources of electric power to distribution subsystems for operation of plant auxiliary electrical equipment at medium and low voltages. Equipment covered in this AMG includes transformers that supply power to site loads during plant start-up, shutdown, and post-shutdown periods (commonly referred to as start-up transformers), and transformers that distribute power to medium- and low-voltage site load centers. These categories include both liquid-immersed and dry-type transformers. Main transformers (i.e., those which supply the offsite transmission system with output from the main generator(s)), unit auxiliary transformers, and auto- and grounding transformers were not included in this guideline, as these components do not fall within the definition of "important to license renewal" for the majority of nuclear plants. However, a limited number of plants may be configured such that the main and auxiliary transformers are within the definition because they are considered as off-site feeds; for these plants, the generic guidance and aging management techniques contained herein could be applied to these components as well.

Transformers important to license renewal are addressed in this AMG. The group of transformers that are important to license renewal includes more equipment than just safety-related transformers. For example, the definition of important to license renewal includes any component or system subject to an operability requirement in the plant's technical specifications. At a minimum for most plants, this would place transformers in the offsite power source paths to the emergency buses within the scope of important to license renewal. The definition of important to license renewal is contained in Section 2.5. The evaluation of the effect of this definition on the scope of a utility's aging management program for transformers is discussed in Section 3.1. Although the types of transformers contained in the grouping "important to license renewal" that are not safety-related are essentially the same as safety-related transformers, they may not have been maintained in the same manner as the safety-related equipment. Therefore, utilities may choose to extend their maintenance practices used on safety-related transformers to the additional transformers covered by the scope of important to license renewal, or to otherwise demonstrate that these practices are not required to effectively manage the aging of the additional equipment. (Note: During review of transformer maintenance practices and procedures from a number of utilities, little difference in treatment between safety-related and non-safety-related transformers was noted.)

The general classifications of transformers that are contained within the grouping of equipment important to license renewal are:

- Transmission Voltage[1] to 13 kVac or 4 kVac
- 13 kVac to 4 kVac[2]
- 13 kVac or 4 kVac to 480 Vac[3]

Electrical distribution lines (i.e., the high-voltage transmission lines supplying power transformers, and the cables distributing power throughout the plant) and protective relays/control devices external to the transformer enclosure are not within the scope of this document. The transformer enclosure (tank), windings, insulation system, core, bushings, cooling system, oil preservation and sampling system, tap changers, supporting internal electrical components, and internal protective and monitoring devices are, where installed, all considered to be within scope.

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[1] Transmission voltages for nuclear plants are typically 500 kVac, 345 kVac, or 230 kVac, although other voltages may be used. Medium voltages are typically 13.8 kVac or 4.16 kVac although other voltages may be used as well. A few plants transform transmission voltage directly to low voltage (i.e., 480 Vac); these applications are included in this category also.

[2] Some plant distribution systems transform medium voltages (such as 13 kVac) directly to 480 Vac, and hence do not use this type of equipment.

[3] The 13-kVac, 4-kVac, and 480-Vac designations are used throughout the remainder of this document although some plants use systems with slightly different nominal voltages.

1.3 Conclusions of This Study

This study evaluated the stressors acting on transformer components, industry data on aging and failure of transformer components, and maintenance activities performed on transformers. The potential aging mechanisms resulting from environmental and operating stressors on transformers were identified, evaluated, and correlated with actual plant experience to determine if the potential aging mechanisms were actually being experienced. Then, the maintenance procedures used by nuclear plant operators were evaluated to determine if the potential and experienced aging mechanisms are being identified and managed. Where an aging mechanism was properly managed, the procedures were deemed to be "effective." Where an aging mechanism was not fully managed or not considered, additional plant-specific activities to manage the aging mechanism were identified.

1.3.1 Potentially Significant Component/Aging Mechanism Combinations Managed by Effective Programs

Evaluation of the components of the transformers, the stressors acting upon the components, and the operational history data indicates that nearly all transformer components have potentially significant aging mechanisms that can affect their function. Evaluation of the failure history coupled with review of existing plant maintenance procedures shows that these aging mechanisms can be managed in the current and license renewal periods. Table 1-1 provides a summary of the components and aging mechanisms, coupled with the maintenance and surveillance technique that manages the aging mechanism. It should be noted that not all components and their aging mechanisms listed in Table 1-1 are applicable to every transformer; each transformer must be evaluated individually to determine which components are installed. Those mechanisms and components applicable to only one type of transformer (either liquid or dry) are so noted. A full tabulation of components, aging mechanisms, maintenance techniques, and periodicities is provided in Table 5-1. Section 5 (Section 5.2 and others) provides additional information on inspection frequencies. Appendix A provides definitions of the terminology used throughout the report.

Table 5-1 provides additional detail for the transformer components listed above. All of the potentially significant aging mechanisms were amenable to aging management through currently available maintenance and surveillance techniques.

1.3.2 Non-significant Component/Aging Mechanism Combinations

Table 1-2 provides a summary of the non-significant aging mechanisms.

Table 1-1. Component and Aging Mechanism Summary

Component	Aging Mechanisms	Maintenance and Surveillance Techniques
Metal Enclosure (Tank) and Cover(s)	Material degradation	Visual inspection; cleaning; painting
	Deterioration of seals & gaskets	Visual inspection; replacement as necessary
	Metal fatigue	Visual inspection; leak testing (liquid or sealed dry-type only); weld or patch repair as necessary
	Loss of fastening components	Visual inspection; replacement of lost components
Primary and Secondary Windings	Degradation of organic supports and spacers	Visual inspection*; insulation resistance testing; power factor testing; gas and oil evaluation (liquid only)
	Formation of localized high temperature areas (hot spots)	Monitoring of temperature indications; sampling and analysis of transformer insulating fluid (liquid only); purification/replacement of insulating fluid as required; cleaning of windings and insulation (dry-type); infrared (IR) inspection
	Loosening of winding mounting system	Visual inspection*; measurement of critical winding/core tolerances
	Winding (conductor) failure	Visual inspection for overheating or breaks in insulation/conductor*; resistance and continuity testing
Magnetic Core	Loosening of core mounting system	Visual inspection; core-to-ground test; measurement of critical core/winding dimensions*
	Core material embrittlement	Visual inspection*
Insulation System (liquid-immersed)	Dielectric breakdown of insulating fluid	Sampling and analysis for dielectric strength, power factor, and water/impurity content; gas and oil evaluation
	Particulate and/or moisture contamination	Visual inspection; dielectric strength testing; analysis for water content
	High acidity	Sampling and laboratory analysis (pH, neutralization number)
	Oxidation and sludge formation	Visual inspection of insulating fluid; laboratory analysis; maintenance of seals and air-tight integrity of tank and oil preservation system components
(Dry-Type)	Thermal deterioration of organic materials	Insulation resistance testing
(Liquid and Dry)	Thermal deterioration of solid organic insulating materials	Load and temperature control; gas and oil evaluation; analysis of insulating fluid for decomposition byproducts; visual inspection* for discoloration, cracking; insulation resistance testing
Bushings	Degradation of organic materials	Power factor and capacitance testing

Table 1-1. Component and Aging Mechanism Summary (continued)

Component	Aging Mechanisms	Maintenance and Surveillance Techniques
Bushings (continued)	Contamination or deterioration of porcelain exterior surfaces	Visual inspection for dust, salt, contamination, cracking, streaking, discoloration, or chipping of porcelain insulator; cleaning or replacement as necessary
	Deterioration and leakage of oil/inert gas	Visual inspection for indications of leakage; verification of bushing oil level; replacement of gaskets/seals as required
	Electrical connection damage or loosening	Verification of connection tightness and check for excessive strain
Cooling System	Wear/fatigue of the pump and fan motor bearings, shaft, and impeller	Visual inspection and verification of normal fan or pump operation (no vibration, abnormal noise, overheating, etc.); periodic lubrication; bearing or component replacement as required
	Degradation of motor winding and lead insulation	Winding insulation resistance testing; replacement of motor and/or leads as required
	Electrical component degradation	Visual inspection and cleaning; functionality testing; replacement as necessary
	Fouling of heat transfer surfaces	Visual inspection and cleaning
Fluid Preservation and Sampling System (liquid only)	Deterioration of organic and inorganic materials	Visual inspection for cracking, rust, corrosion, or other deterioration; cleaning; painting and preservation; functionality testing; replacement as required.
	Wear of mechanical components	Inspection for looseness or loss of adjustment; measurement and adjustment of component tolerances; lubrication; replacement as required
	Loss of component adjustment	Verification of proper pressure regulating valve operation; cleaning and adjustment as required
Tap Changers (Load Tap Changer; liquid only)	Wear of mechanical components	Verification of component tolerances and adjustment
	Deterioration or failure of electrical components	Visual inspection and cleaning; electrical and functionality testing; replacement as necessary
	Degradation of organic insulating materials	Visual inspection of components for cracking or other loss of mechanical properties; insulation resistance testing
	Loss of adjustment of braking systems	Visual inspection of linings for wear; verification of proper braking system adjustment and torque; replacement of brake linings when required
	Wear of main contact surfaces	Visual inspection of moving and stationary contact surfaces for wear or contamination; cleaning, reconditioning, or replacement as necessary.

Table 1-1. Component and Aging Mechanism Summary (continued)

Component	Aging Mechanisms	Maintenance and Surveillance Techniques
Tap Changers (Load Tap Changer; liquid only) (continued)	Tap changer compartment leakage	Visual inspection for leakage or deteriorated gaskets; verification of proper oil level
Fault Pressure Relay (liquid only)	Degradation of organic seals and gaskets	Visual inspection for signs of leakage, cracking, or other gasket/seal degradation
Bushing Current Transformers	Degradation of organic insulating materials	Insulation inspection; electrical testing
Pressure Relief Devices (liquid and sealed dry-type only)	Degradation of seals	Functionality testing**; visual inspection for seal degradation
Temperature Indicators	Failure of hot spot heating coil element	Periodic verification of temperature sensor functionality and accuracy

* Generally only accomplished during invasive maintenance procedures requiring disassembly, draining, and/or untanking. Inspection of this type would be an uncommon practice performed only after failure or when a significant problem was indicated by other symptoms or tests.

** Generally performed only when device removed/replaced or under other similar conditions.

Table 1-2. Summary of the Non-significant Aging Mechanisms

Component	Aging Mechanism	Maintenance and Surveillance Techniques
Fault Pressure Relay (liquid only)	Wear of mechanical components	Periodic functional testing of relay*
	Electric switch failure	Periodic functional testing of relay*
No-Load Tap Changers	Contact surface and mechanism wear	Visual inspection; functional testing
Resistance Temperature Detectors	Corrosion	Periodic calibration
	Mechanical shock	Periodic calibration
Thermocouples	Thermal degradation	None
Pressure Relief Devices (liquid and sealed dry-type only)	Spring relaxation	Periodic functional testing of relief*
Flow Indicator (liquid only)	Wear of internal components	Visual inspection for operation
Control Compartment Space Heater	Failure of heating element	Visual inspection; verification of operation

* Generally performed only when device removed/replaced or under other similar conditions.

1.3.3 Potentially Significant Component/Aging Mechanism Combinations Requiring Plant-Specific Management

Section 5 of this report evaluates the maintenance procedures for power and distribution transformers and concludes that transformers maintained in accordance with the guidance contained in Sections 5.2 and 5.3 will be subject to an effective maintenance program as required for license renewal, subject to the following limitations:

- Dielectric Breakdown of Insulating Fluid. Failure data for large liquid-immersed transformers indicate that failures are primarily detected during operation and that they frequently resulted in preclusion of the transformer's required function(s). Many of the more damaging failures (such as explosions and fires) occurred as a result of dielectric breakdown of the insulating fluid. This breakdown can be precipitated by various conditions, such as moisture contamination and abnormal gas formation in the fluid, and may be detected by various types of laboratory and/or in-situ analysis. Hence, periodic fluid analysis and gas monitoring appear to be the most effective means of identifying incipient failure in large liquid-immersed transformers.

- Bushing Flashover. Bushing flashover has occurred on several occasions; this mode of failure can result in substantial damage to the affected bushings (and transformer) as well as affecting the transformer's required function(s). Contamination and subsequent flashover is primarily caused by airborne dust and/or salt spray accumulation on exterior bushing surfaces acting in combination with rain or high humidity. This problem can be avoided through periodic removal of the dust/salt deposits or through the use of special bushing coatings.

- Deterioration of Solid Insulation. Degradation of solid transformer insulation (i.e., organic materials such as wood, paper, or resins) results primarily from exposure to heat generated within the transformer/windings (applicable to both liquid and dry units), and exposure to the insulating fluid in which the material is immersed (liquid only). Although generally a very slow process, deterioration of the solid insulation proceeds essentially unimpeded during the life of the unit. This deterioration may be monitored through periodic visual inspection (when accessible) or insulating fluid analysis (liquid only).

Accordingly, operators with liquid or dry-type transformers installed at their nuclear plants should consider implementing the following actions (as applicable):

1. Review and evaluate the adequacy of existing maintenance, analysis, and testing programs with relation to the manufacturer's recommendations and other industry guidance; specific care should be taken to ensure that comprehensive insulating fluid analysis and bushing cleaning are conducted with sufficient frequency so as to limit the probability of catastrophic transformer failure. If existing testing and maintenance procedures are not adequate, upgrade the programs as necessary.

2. When failures of the main insulation system occur for transformers or their components, conduct a root-cause evaluation. Implement those corrective actions necessary to mitigate the effects of the identified causes.

In addition, plant-specific review of the maintenance program is recommended if:

- The transformer experiences abnormal electrical loading conditions (such as loading for a significant period beyond rated condition, significantly unbalanced voltages, or fault conditions). Then, procedures should require the transformer to be evaluated as soon as practical after the abnormal occurrence to ensure that no damage that could potentially affect the required operation of the transformer has occurred.

- The transformer is exposed to ambient temperatures in excess of 40°C [104°F] (or 30°C [86°F] average temperature for any 24-hour interval) for extended periods (unless specifically designed for operation at elevated temperature). Then, the periodicity of maintenance and surveillance should be reviewed to verify that the insulation system and other organic components such as solid insulation and gaskets have not been adversely affected by the elevated operating temperature.

- The transformer is subject to environments containing high levels of dust, dirt, or other airborne contaminants such as salt or chemical vapor. Then, the procedures for maintenance of the transformer should be reviewed to verify that (1) any filters (dry-type units only) protecting the transformer from dust or particulates are inspected and cleaned at sufficient intervals, (2) heat transfer surfaces (such as radiator cooling fins) are periodically inspected and cleaned to preclude fouling, (3) periodic inspection of the primary/secondary windings for signs of contamination and/or degradation and any required cleaning is conducted (dry-type), and (4) inspection and cleaning (or application of protective coatings) of the bushing surfaces is conducted at sufficient intervals to preclude instances of surface tracking and possible flashover.

More detail on these issues is contained in Section 6.

1.4 References

None.

3.6.1 Description of Industry-Wide Operating Experience with Components; NRC and INPO Documentation

The following subsections discuss those NRC and INPO documents detailing failures associated with power and distribution transformers. It should be noted that although some of these failures involved transformers not within the scope guideline (such as main and auxiliary unit transformers), many of the aging and degradation mechanisms described are substantially similar and accordingly were included below.

3.6.1.1 Liquid-Immersed Transformers

IE Information Notice 82-53, "Main Transformer Failures at the North Anna Nuclear Power Station," [3.96] describes seven main transformer failures at North Anna. The failures were determined to be due either to winding to ground faults (3) or high-voltage bushing to ground failures (4). Investigation suggests that the following circumstances contributed to the failures:

1. Exposure to Fault Conditions. At least once before their respective failures, several of the transformers involved had been used in operation in a bank of transformers where one of the companion units had failed.

2. Over-voltage. Prior to several of the failures, the transformer bank containing the failed transformers had been subjected to several documented and undocumented over-voltage conditions.

3. Improper Storage. The high-voltage bushings for these transformers were improperly stored (i.e., in a horizontal position). Improper positioning during transportation and storage periods results in incomplete oil coverage of the inner surfaces of the bushing; the absence of oil allows the gas in the expansion cap to permeate any exposed paper layers. Once gas permeates the paper, the bushings become sensitive to electrical degradation, and a significant time period is then required to re-impregnate the paper with oil. Bushings with this type of degradation are also susceptible to corona discharges during over-voltage conditions.

Many of these failures generated sufficient forces and heat to rupture the transformer's casings. The oil that erupted from two of these breaks ignited; the resulting fires engulfed and shorted out an overhead three-phase bus system.

INPO SER 13-85 [3.97] describes several transformer insulator (bushing) phase-to-ground failures resulting from combinations of condensation, salt accumulation, dust, and chalk powder. The following observations regarding these events were made:

1. Airborne contaminants in combination with condensation can dramatically reduce the phase-to-ground resistance of the external surfaces of bushing insulators. Periodic inspection, phase-to-ground resistance measurement, and cleaning are effective means of avoiding this problem. Spray washdown systems and silicone-based coating compounds may also be effective alternatives.

INPO SER 24-84 [3.98] describes the failure of several nuclear plant transformers resulting in fires. The following observations regarding these failures were noted:

1. Transformer fires are most commonly caused by degradation of the winding insulation. Arcing which results from small insulation faults intensifies over time, thereby generating significant quantities of gaseous byproducts from the decomposition of insulating materials. These gases increase in concentration and pressure, potentially resulting in explosion and fire with exposure to an ignition source (such as internal transformer faulting).

2. Switchyard transformers which experience periodic overloads are also prone to explosion due to the release and collection of combustible gases. These gases are held in solution in the insulating fluid during operation, and may be released upon transformer trip and subsequent rapid cooldown. Exposure to ignition sources such as internal faulting may trigger the explosion.

3. Contamination of the insulating fluid with water reduces the dielectric strength and facilitates the formation of both combustible and non-combustible gases. This can result in sludge formation and explosive gas mixtures. Periodic laboratory or in-situ analysis can detect such degradation prior to catastrophic failure.

3.6.1.2 Dry-Type Transformers

IE Information Notice 83-37, "Transformer Failure Resulting From Degraded Internal Connection Cables," [3.99] describes a failure due to an in-rush current on a dry-type ITE 4160-/480-Vac transformer initiating major arcing in the transformer winding tap lug causing the transformer failure. The failure was attributed to improper assembly of transformer winding tap cables and long-term undiagnosed, heat-induced degradation. It was believed that the set screw, which attaches the cable to the barrel of the lug, was over-tightened during installation, which caused some strands of the aluminum wire to break, thereby creating a high resistance joint. Arcing is thought to have started in the barrel of the lug as a result of the high resistance joint. Long-term localized heating in the terminal lug over a period of time weakened and degraded the connection.

NRC Information Notice 92-63, "Cracked Insulators in ASL Dry Type Transformers Manufactured by Westinghouse Electric Corporation," [3.100] addresses problems that could result from the cracking of ceramic insulators on ASL Dry Type Power Center 4160/480 V 3-phase transformers. Typically the cracks were found in the center portion of the insulators where a series of annular indentations form rings or skirts. Some of the insulators in the affected transformers were installed off-center and were not perpendicular to the pressure ring, thereby facilitating cracking. The Notice stated that the cracking of the insulators could have a catastrophic effect on the structural integrity of the transformer.

3.6.2 Evaluation of NPRDS Data

To substantiate the stressors and aging mechanisms postulated for power and distribution transformers, actual plant component failure data were reviewed. One of the primary sources of this type of failure data is the INPO NPRDS. Failure records contained in NPRDS include such information as the voltage rating and manufacturer, type of equipment, date of discovery, cause category, and a brief narrative describing the event. NPRDS data are not focused directly on component aging, as it does not typically address the root cause or mechanism of component degradation. Additionally, not all degradations observed during maintenance activities are identified in the database. Not all plants have provided NPRDS data, and some may not have reported for their entire period of operation. As a result of these limitations, the database cannot be readily used to provide probabilistic information about the reliability of a specific population of components with respect to age-related degradation. However, the data can be used to identify those transformer components that have a high incidence of degradation or failure relative to other components within the same equipment.

By permission of INPO, failure and deterioration data contained in the NPRDS database were reviewed as part of this study. Several hundred reports were identified when the database was searched. Data pertinent to power and distribution transformer component failures were identified; those pertaining to equipment not within scope (such as unit main and auxiliary transformers) were deleted. The remaining reports were then individually evaluated to determine their applicability to aging and aging mechanisms. Failure reports deemed to be applicable were then grouped by transformer type (i.e., liquid-immersed or dry), voltage/power rating, manufacturer, and component; each component failure grouping was then sorted by failure mode, failure cause, and method of failure detection. The following subsections summarize the specific observations by manufacturer and component. A summary of the overall findings of the NPRDS review is provided at the end of this section.

In several cases, the failure mode and/or failure cause were not identified; these reports were tagged as "unidentified." This was especially prevalent with respect to winding failures as the root cause or circumstances surrounding these failures are not always easily identified; in-depth failure analysis (especially on the smaller distribution transformers) is often protracted or not conducted. These type of reports do, however, provide additional perspective as to the fraction of total reports (related to a specific component) that did not contain sufficient information for analysis. In those cases where substantial percentages of the reports cannot be attributed to any failure mode or cause, the degree to which these reports represent the total population may be suspect. For example, if most of the "unidentified" failures for a given component are in fact attributable to one or two modes or causes (as opposed to being proportionately distributed among all of the modes or causes), the data (and results) are accordingly skewed. In sum, the accuracy of the conclusions is, to a degree, related to the percentage of "unidentified" reports present for the individual component.

It should also be noted that "normal aging" was cited in numerous reports as the cause for the component/subcomponent failure. In most cases, this term is not descriptive of the actual failure cause; however, these reports were assigned their own failure cause category so as to differentiate them from other causes and provide some indication of the fraction of total failures that these reports constituted.

Many of the reports pertinent to this analysis required a substantial degree of interpretation; incomplete and even contradictory descriptions of the circumstances surrounding the failure were sometimes noted. In cases where the ambiguity could not be resolved with any degree of certainty, the report in question was not used. Due to the uncertainty inherent in some of the data, the relative proportions of various types of failures may differ somewhat from the "actual" values; this potential error was assumed to be evenly distributed (that is, reports erroneously attributed were assumed not to affect one component, failure mode, or failure cause grouping disproportionately in relation to another).

The method of failure detection refers to the circumstances under which the component failure was noted. Different categories of detection method were considered, including detection during maintenance, detection during surveillance testing, during operations, and during in-service inspection. Those failures detected during operation of the equipment were further categorized as to the effect of the detection on the functionality of the transformer. For example, a transformer failure noted during operation which prevented or limited the transformer from fulfilling its required function was categorized separately from a failure detected during transformer operation which had no appreciable effect on the functionality of the unit.

Those NPRDS reports resulting from prior equipment maintenance, modification, or surveillance testing (as differentiated from events detected during these activities) were classified as "maintenance-induced"; failures resulting from maintenance-induced causes were identified in each of the discussions presented below, yet were not included in the component/failure mode/failure cause analysis. Maintenance-induced events, although not strictly an aging mechanism, do constitute a viable mechanism for transformer component degradation over time. Section 3.6.2.2.4 of this guideline discusses maintenance-induced events in further detail.

Protective and monitoring devices (including fault pressure relays, pressure relief valves, gas detectors, and temperature sensors) were included in the following analyses because, in many cases, failure of these components may either result in disruption of the function of the transformer, or place the transformer in an unprotected state, thereby making it vulnerable to damage from certain other component failures. For example, failure of the fault pressure relay will cause a trip of the transformer. Similarly, failure of a pressure relief valve may make the transformer susceptible to tank rupture in the event of in internal fault. In most cases, protective devices are located in or on the transformer (with the exception of remote alarms, indicators, and electrical protective relays) and are therefore considered integral components.

Electrical components (such as motor starters, contactors, etc.) were not explicitly considered in the failure analysis because their applications vary so widely, and in many situations may not be considered as part of the transformer by the reporting facility. In-depth analysis of motor control center (MCC) electrical components (including those commonly used in transformers) is performed in Reference 3.72.

The subsections that follow analyze the NPRDS data in several different ways. As stated above, data was segregated based on the type of transformer (dry-type or liquid-immersed). For each of these two types, the following analyses were conducted:

1. Data for all manufacturers and components are collectively examined to determine the relative proportions of component failures, failure modes, failure causes, and methods of detection (Sections 3.6.2.1.1.1 and 3.6.2.1.2.1).

2. Data specific to each manufacturer are analyzed in a fashion similar to that described in 1 above (Sections 3.6.2.1.1.2 and 3.6.2.1.2.2).

3. Data for all manufacturers are collectively analyzed based on voltage and power rating (Sections 3.6.2.1.1.3 and 3.6.2.1.2.3). (Note: Data specific to each manufacturer was not analyzed based on voltage and power rating due to the fact that some manufacturers may produce transformers which are completely contained within one voltage class; hence any inferences based on these data would necessarily be skewed).

Collectively, these analyses help characterize transformer failures as indicated by the NPRDS database.

Figures 3-16 through 3-23 are pictorial representations of the analyses. These plots show the relative distribution of component failures, failure modes, failure causes, and methods of detection. (Note: Due to the inaccuracies and uncertainties present in the data, as well as the small total number of reports, all percentage values listed in the following sections are rounded to their nearest whole digit.)

3.6.2.1 Liquid-Immersed Transformer Failure Analysis

3.6.2.1.1 Component Failure Analysis (all manufacturers)

A total of 72 events from 32 different nuclear units were recorded for liquid-immersed power and distribution transformers of the type considered by this guideline. Of these 72 events, 6 were considered maintenance-induced, and were therefore discounted from further analysis. Figure 3-16 shows a graphic representation of the failure data compiled for the remaining 66 reports. As shown in the figure, load tap changer failures constituted the highest single percentage of failures (10 reports/15%), followed closely by transformer tank/enclosure components (14%). The next most prevalent component to fail was gas monitoring units (11%); it should be noted that protective and monitoring devices (such as gas detectors, fault pressure relays, pressure relief valves, etc.) collectively comprised 32% of the failures noted. The remaining categories (bushings, insulation, windings, cooling systems, etc.) accounted for the remaining 39% of the total.

The single most common failure mode for liquid-immersed transformers was leakage (20% of all reports), followed by low electrical resistance/short circuit (11%) and failure of winding insulating materials (9%). Eleven of the 66 reports (17%) listed an unidentified failure mode. See Figure 3-17.

Significant failure causes included normal aging (26%) and moisture/dirt contamination (17%); 42% of the reports could not be attributed to any specific cause.

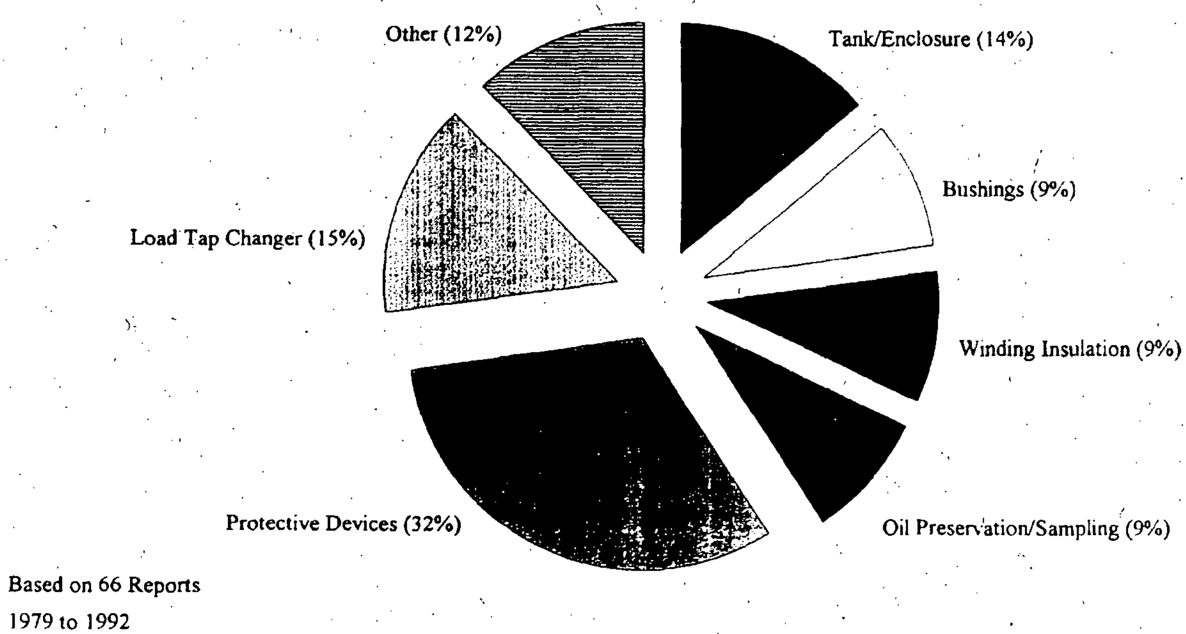

Figure 3-16. Liquid-Immersed Transformer Component Failures (NPRDS).

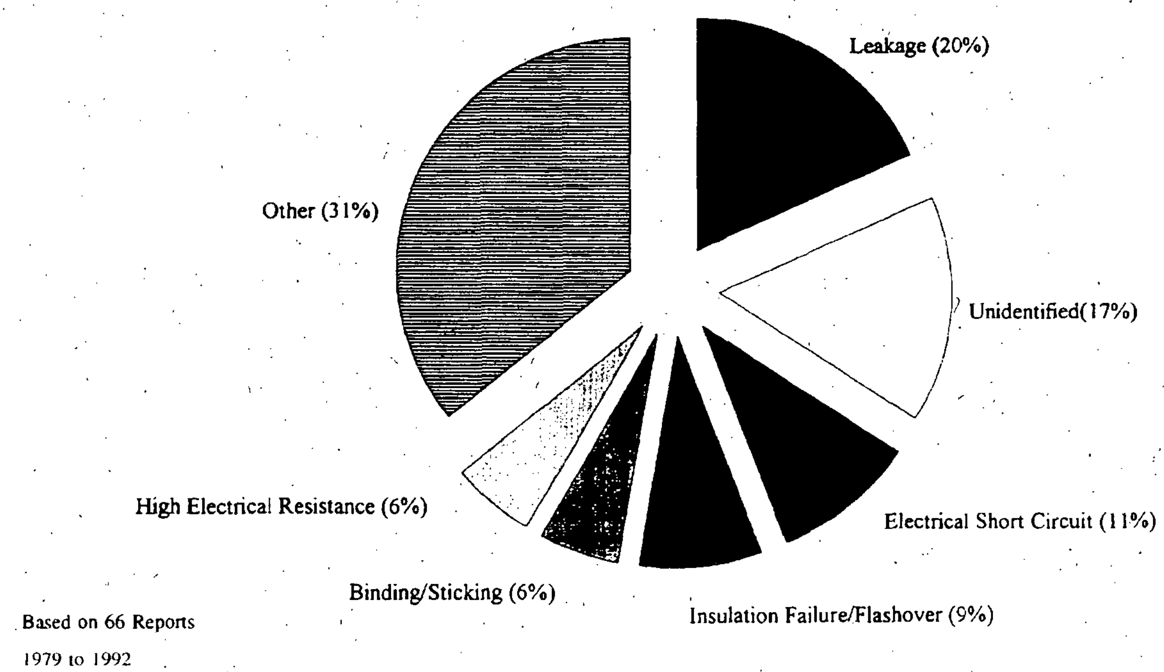

Figure 3-17. Liquid-Immersed Transformer Failure Modes.

The majority of failures noted in the reports were detected during operation of the transformer (see Figure 3-18); 85% of all failures involving liquid-immersed transformers were detected in this manner. Twelve percent and 3% of the total number of reports were detected during maintenance and surveillance testing, respectively. Of the failures detected during operation (85%), 36% affected the required function of the equipment; the remaining 49% had no effect on the transformer's required function.

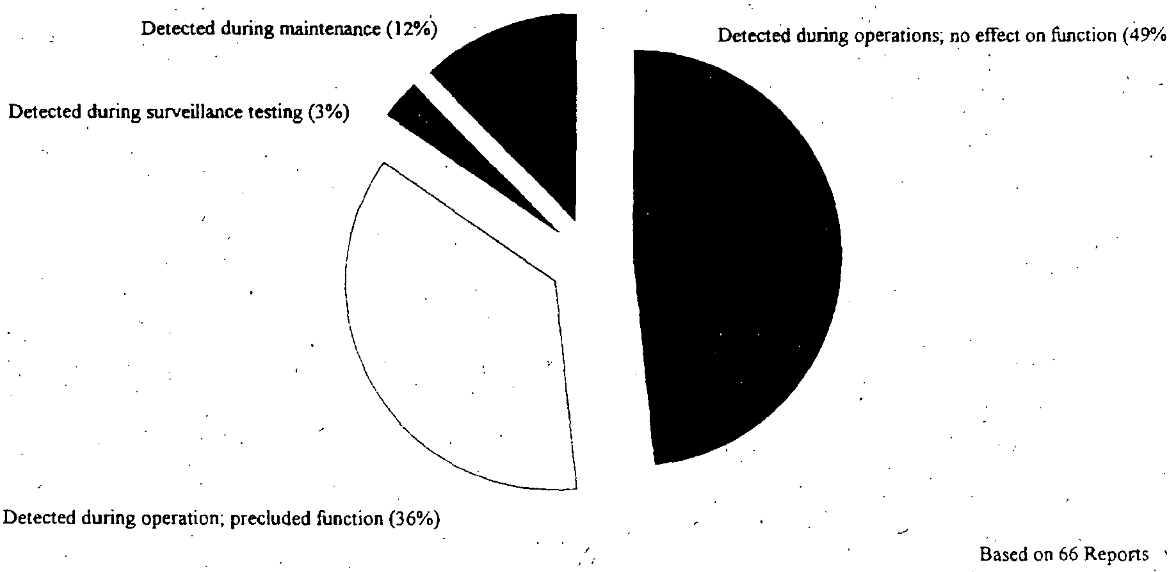

Figure 3-18. Method of Detection for Liquid-Immersed Transformer Failures.

3.6.2.1.2 Liquid-Immersed Transformer Component Failure Analysis (Manufacturer Specific)

Data for liquid-immersed transformers from six different manufacturers (General Electric, Westinghouse, McGraw-Edison, ITE/Gould/Brown Boveri, Moloney, and Federal Pacific) were included in the NPRDS reports analyzed in this guideline; evaluations of this data are presented in the following sections.

3.6.2.1.2.1 General Electric

A total of 23 failure reports were gathered for General Electric equipment; none of these were induced by maintenance activities (maintenance-induced). Load tap changers, tank/enclosure components, and oil preservation and sampling system components each accounted for 13% (3 of 23) of the total number of reports. The remaining components comprised the remainder of the failures, with no single component having more than two failures.

Leakage of oil or insulating fluid was the most significant failure mode for the GE transformers; 6 (26%) of the 23 applicable reports involved leakage of one component or another.

No predominant failure causes were noted, with the majority of reports having an unidentified cause. Twenty two of the 23 failures were detected during operation; only 6 of the 22 resulted in the transformer's failure to operate.

3.6.2.1.2.2 Westinghouse

A total of 25 failure reports were gathered for Westinghouse liquid-immersed power and distribution transformers. Two failures were considered maintenance-induced events. Gas monitor units comprised the largest percentage of the remaining failure reports (4 reports/17%). Reports associated with fault pressure relays, tanks/enclosures, and bushings were next most numerous (13% each). The remaining component categories collectively accounted for the remaining 44%.

Failure modes for the Westinghouse transformers included degradation of organic insulating materials, leakage, and electrical short circuits, each comprising 17% of the total number of failures. Seventeen percent of the reports listed no failure mode.

Predominant failure causes included moisture/dirt contamination (39%) and normal aging (22%); 35% of the reports had an unidentified failure cause. Eighteen of the 23 failures were detected during operation; 8 of these 18 (44%) were identified as having prevented the transformer from performing its required function.

3.6.2.1.2.3 McGraw-Edison

A total of 9 reports were applicable to McGraw-Edison transformers; one failure was maintenance-induced. Each of the remaining 8 failures were attributable to a different component; hence, no components were identified as being potentially problematic. Similarly, failure modes, failure causes, and method of detection for McGraw-Edison equipment were seemingly randomly distributed as well.

3.6.2.1.2.4 ITE/Gould/Brown Boveri

A total of 6 reports related to ITE/Gould/Brown Boveri transformers were identified. Of these reports, 2 were related to the tank/enclosure, 2 to the oil sampling and preservation system, one to the bushings, and one to a temperature detector. The failure modes for the two tank failures were both listed as weld failure, with cyclic fatigue as the root cause. The failure mode and cause of the preservation/sampling system failures were leakage due to normal aging. None of the failures affected the required function of the equipment, and none were maintenance-induced.

3.6.2.1.2.5 Moloney

A total of 5 reports were cited for Moloney equipment; all from the same plant. None of these failures were considered maintenance-induced. Four of the 5 reports (80%) were related to failure of the load tap changing mechanism. Additionally, many of the reports had an unidentified failure mode and/or cause, making the identification of any commonality difficult. All failures did result in the inability of the equipment to perform its required function.

3.6.2.1.2.6 Federal Pacific

Only one failure was reported for Federal Pacific liquid-immersed transformers; this was a failure of the insulation system attributed to dielectric breakdown of a phase winding. This failure resulted in the tripping of the transformer.

3.6.2.1.3 Voltage and Power Rating Analysis (all manufacturers)

Data relating to liquid-immersed transformers (all manufacturers) was examined to determine if any relationships between the rate of failure and the voltage/power rating existed. For the purposes of this analysis, transformers were categorized by their voltage as either transmission, inter-bus, or distribution. Transmission transformers were defined as those units which transform transmission voltages (100 kV and greater) to medium- or low-voltages (such as 13.8- or 4-kV) for on-site use. Startup transformers are examples of this type of equipment. Inter-bus transformers, on the other hand, are used to reduce the output voltage of the transmission-type transformers (which may be used to supply large plant loads such as service water or reactor coolant pumps) for use by plant medium or low voltage load centers. An example of this type of transformer might be one which reduces voltage from 13.8-kV to 4160- or 480-V. Finally, distribution transformers were defined as those used to reduce medium voltages (such as those derived from 4160-V load centers) for use by low-voltage (480-V) plant loads.

As indicated in Figure 3-19, of the 66 reports applicable to liquid-immersed transformers, 32 (49%) involved transmission equipment, 26 (39%) involved inter-bus transformers, and 8 (12%) involved distribution transformers. When only the failures detected during operation which resulted in preclusion of the transformer's required function (24 total reports) are considered, the following results are noted: 18 of the 24 reports (75%) involved main power transformers, and the remaining 6 (25%) were related to inter-bus type units (see Figure 3-20).

3.6.2.2 Dry-Type Transformer Failure Analysis

3.6.2.2.1 Component Failure Analysis (all manufacturers)

A total of 32 events from 15 different nuclear units were recorded for dry power and distribution transformers of the type considered by this guideline. Of these 32 events, none were considered maintenance-induced. Figure 3-21 shows a graphic representation of the failure data compiled for these 32 reports. As shown by the figure, primary/secondary winding insulation failures constituted the highest single percentage of failures (15 reports/47%), followed by cooling system components (25%). All other component failures occurred with substantially less frequency, collectively accounting for the remaining 28% of the reports.

The single most common failure *mode* for dry type transformers was degradation/failure of organic insulating material (44% of all reports). Five of the 32 reports (17%) listed an unidentified failure mode. The remaining 39% of the reports were associated with several different failure modes (Figure 3-22).

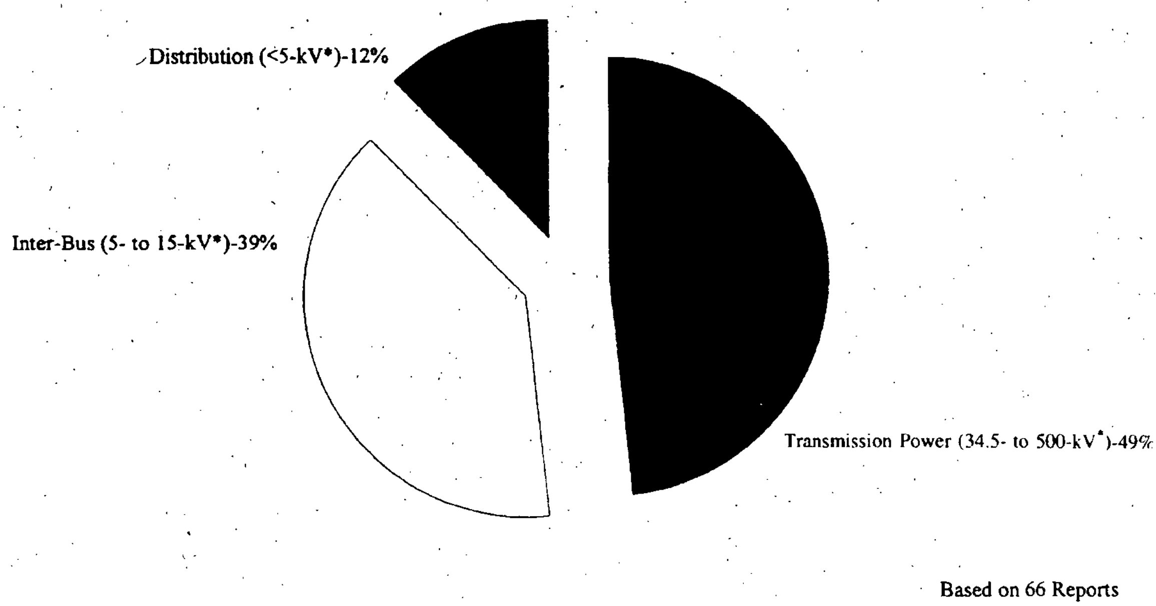

Figure 3-19. Liquid-Immersed Transformer Failures (By Input Voltage Category).

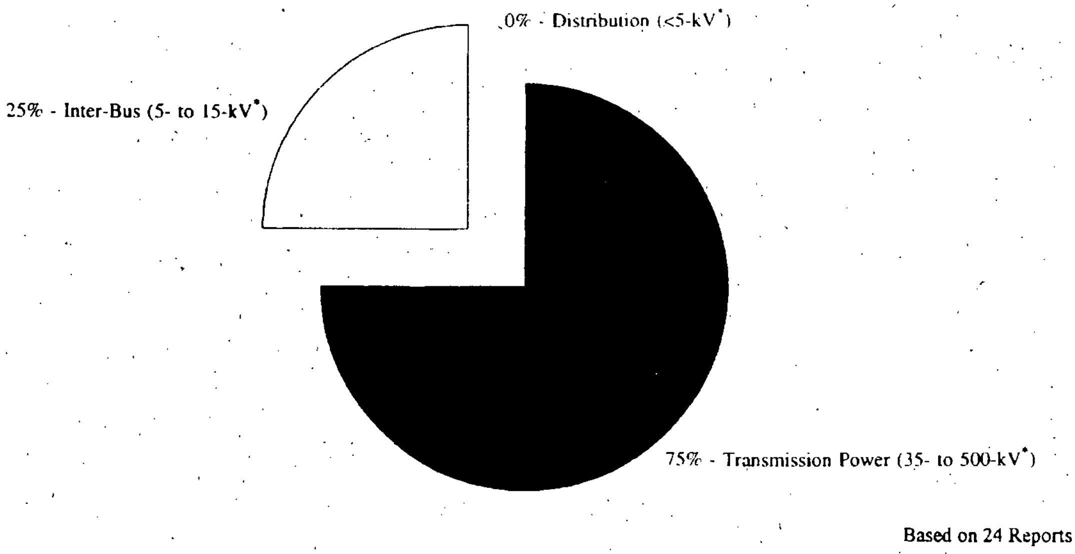

Figure 3-20. Liquid-Immersed Transformer Failures to Operate** (By Input Voltage Category).

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* High-side winding voltage

** Failure to operate is defined as the inability of the transformer to fulfill its required function.

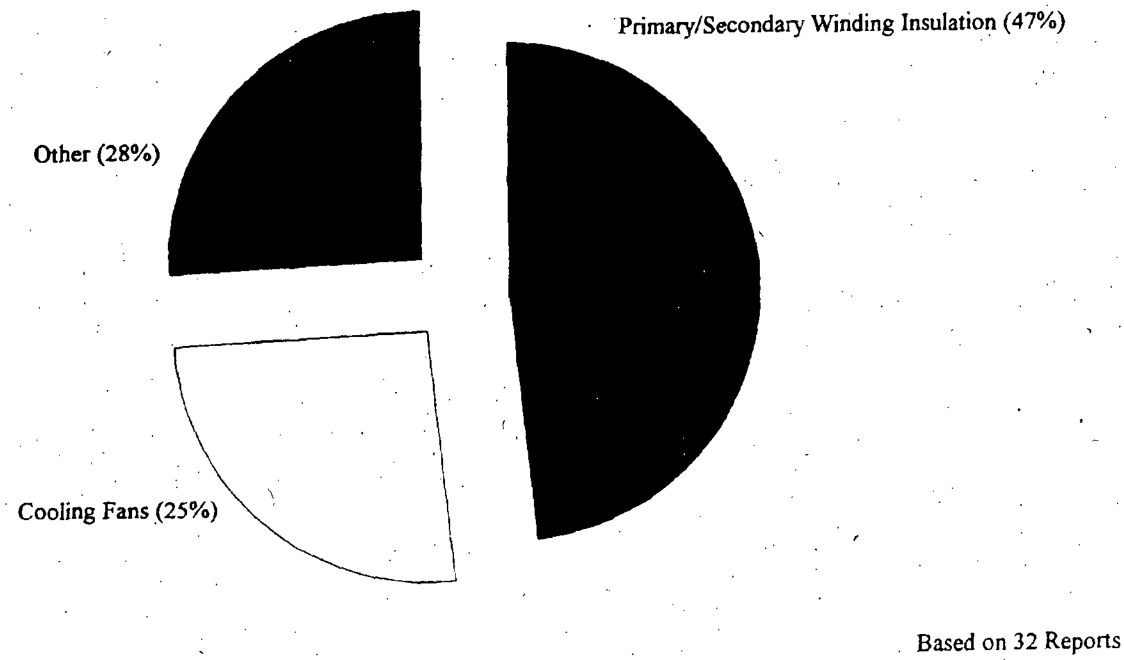

Figure 3-21. Dry-Type Transformer Component Failures.

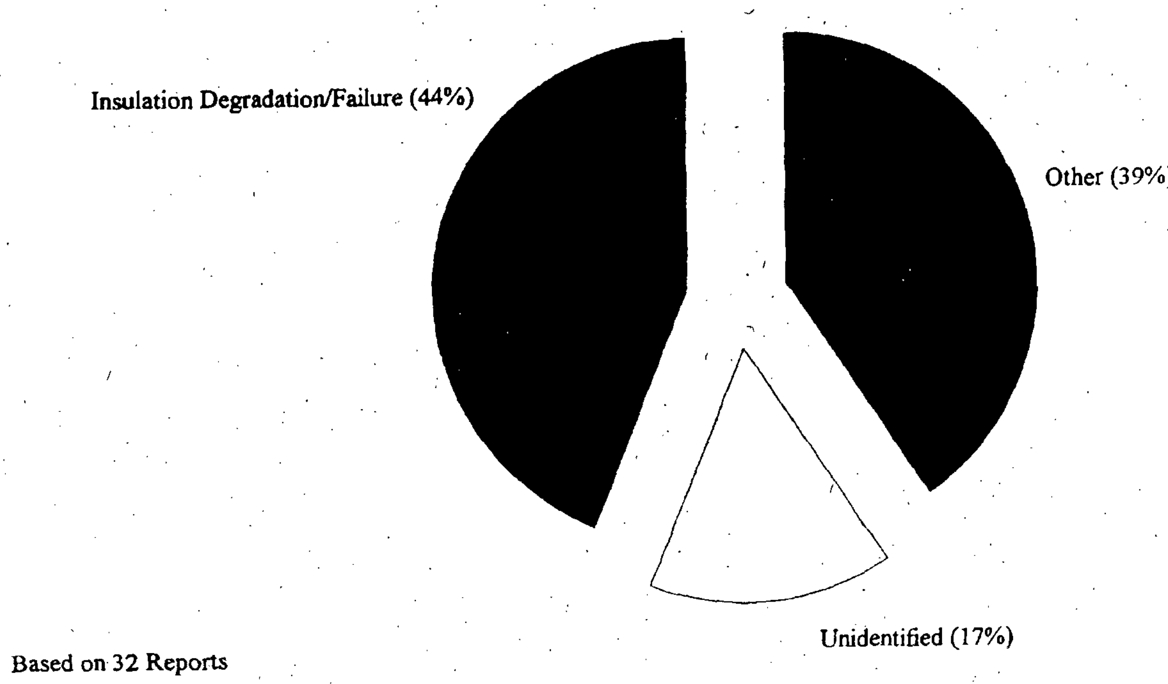

Figure 3-22. Failure Modes for Dry-Type Transformers.

The only significant failure *cause* noted was normal aging (25%); the remaining reports had no identified failure cause.

The majority of failures noted in the reports were detected during operation of the transformer; 84% of all failures involving dry type transformers were detected in this manner. 13% and 3% of the total number of reports were detected during maintenance and in-service inspection, respectively. Of the failures detected during operation, 50% affected the required function of the equipment; the remaining 34% had no immediate effect on the transformer's functionality (Figure 3-23).

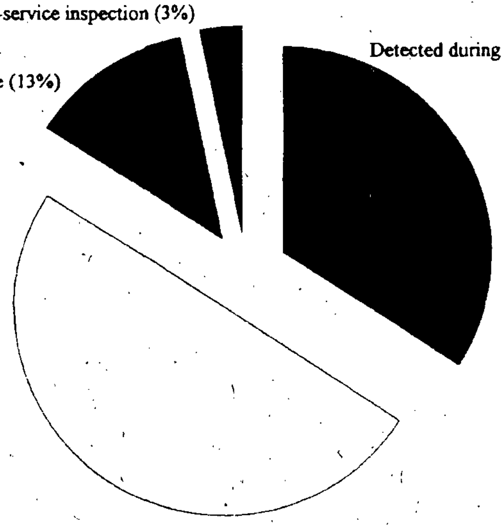

Figure 3-23. Method of Detection for Dry-Type Transformer Failures.

3.6.2.2.2 Component Failure Analysis (Manufacturer Specific)

Data for dry-type transformers from four different manufacturers (ITE, General Electric, Westinghouse, and BBC) was included in the NPRDS reports analyzed in this guideline; evaluations of this data are presented in the following sections.

3.6.2.2.2.1 ITE

A total of 15 failure reports were identified for ITE equipment; none of these failures were maintenance-induced. Cooling system components (predominantly fans) comprised 53% of the failures, whereas 40% were attributable to the primary/secondary winding insulation. The remaining components comprised the remainder of the failures, with no single component having more than two failures.

Degradation of organic insulating material was the most significant failure mode for the ITE transformers; 5 of the 15 applicable reports involved degraded insulation.

Normal aging was the most significant identified failure *cause* (27%); however, a full two-thirds (67%) of the reports failed to identify any cause.

All of the failures noted were detected during operations; of these failures, one-third (5) resulted in failure of the transformer to perform its required function, whereas two-thirds (10) had no immediate effect.

3.6.2.2.2.2 General Electric

A total of 11 failure reports were generated for GE dry-type power and distribution transformers. None of these failures were considered to be maintenance-induced events. Primary/secondary winding insulation failures comprised the largest percentage of reports (9 reports/82%).

Eight of the 11 reports listed degradation of organic insulating materials as the failure mode. Although the preponderance (82%) of the reports listed no failure cause, nearly all of the failures resulted in preventing the transformer from performing its required function.

3.6.2.2.2.3 Westinghouse

Three reports related to Westinghouse dry-type transformers were identified. Of these reports, 2 were related to cracking of the bus insulator supports, which was determined to be the result of a manufacturing defect. The remaining failure was related to the installed temperature indicator. None of the failures affected the required function of the equipment, and none were maintenance-induced.

3.6.2.2.2.4 ITE/Brown Boveri

Only one report was noted for ITE/Brown Boveri dry transformer equipment; this was related to heat damage of the electrical connections to the transformer, and was not maintenance induced. The function of the transformer was affected by this event.

3.6.2.2.3 Voltage and Power Rating Analysis (all manufacturers)

All dry-type transformer failures noted in the NPRDS data were related to transformers of the distribution type (i.e, all similar voltage and power rating). Accordingly, no further sub-classification of the data with respect to these ratings can be made.

3.6.2.2.4 Conclusions from NPRDS Review

As indicated above, the NPRDS data are not specific to aging-related information. In many instances, the scope was limited with respect to the number of plants and the time period reported. Data for many manufacturers was numerically insufficient to substantiate any specific inferences. Despite these limitations, however, several observations can be made about the various classes of transformers evaluated.

General Conclusions

1. When considering the failure data for all manufacturers collectively, no one component or subsystem associated with liquid-immersed transformers had a failure rate which was significantly larger than that of other components. Insulation failure and dielectric breakdown, although potentially catastrophic, were no more likely to occur than other types of failures.

2. The majority of all transformer failures (both liquid and dry) were detected during operation of the unit. Of these failures, a significant percentage (40%) resulted in a failure of the transformer to function; however, small distribution-type liquid units were a notable exception (see the following conclusion).

3. Larger transmission and inter-bus liquid-immersed transformers accounted for significantly more failures than the smaller distribution-type liquid units. The relative population sizes of each class of liquid transformer are unknown; however, the data seems to indicate that units with higher voltage and power ratings experience a higher rate of failure. No failures of the smaller distribution type liquid equipment (< 5 MVA) resulted in the transformer's inability to perform its required function(s).

4. For dry-type transformers, failures of the primary/secondary winding insulation and cooling system (fans) are most significant. Degradation of the insulation accounted for nearly half of all failure reports for dry-type equipment; cooling fans comprised one quarter of all reports. Almost half of all the failure reports noted for dry-type transformers also resulted in the failure of the unit to perform its required function.

Manufacturer-Specific Conclusions

1. Based on the failure data provided, no highly problematic components were identified for any manufacturer's liquid-immersed type equipment considered in this guideline. Two considerations related to this observation should be noted, however:

   - Relatively few failure reports were observed for each manufacturer; therefore, inferences concerning the relative dependability of systems or components could not be reliably made. Hence, although no problematic components or systems were identified, it cannot be definitively stated that no such problems exist.

   - Not all manufacturer's equipment is necessarily covered by the NPRDS data (i.e., failures of other manufacturer's equipment may have occurred yet were not reported to the system)

2. For dry-type transformers, failure data for the individual manufacturers was for the most part consistent with the overall failure data (i.e., significant percentages of winding insulation and cooling system component failure); due to the low total

number of reports, however, no inferences concerning the reliability of a specific manufacturer's transformers or components can be made.

Maintenance-induced events accounted for varying percentages of the total number of failures recorded for each transformer type and manufacturer; although not considered an aging mechanism per se, these events do represent a factor to be considered in the aging of the equipment. A high incidence of maintenance-related degradations and/or failures is potentially indicative of erosion of the skill/knowledge level of personnel maintaining the equipment or relaxed attention to detail and should be addressed in a fashion similar to that of more conventional aging mechanisms.

Maintenance induced events comprised only 8% of the total number of reports relating to liquid-immersed transformers, and 0% of the reports relating to dry-type transformers. Hence, in sum, maintenance-induced events constituted less than 6% of reports related to all types of transformers considered in this guideline. This result indicates that improper maintenance techniques do not appear to be a very significant aging mechanism for either dry or liquid-immersed transformers.

3.6.3 Evaluation of LER Data

NRC LERs are another source of transformer failure and degradation data. LERs are issued by nuclear plant operators when equipment failures and plant operating events meet the reporting requirements specified in 10 CFR 50.73. As with NPRDS data, LERs are not oriented directly toward recording data related to component aging. In addition, the criteria for issuance of an LER do not encompass all component failures (especially those of little or no consequence to plant safety). Hence, evaluation of LER data provides only a partial picture of failure information; accordingly, the data may or may not be representative of general equipment failure behavior. LER data can be used, however, as support for the findings derived from other data sources (such as NPRDS and industry studies), as well as for verification of postulated aging mechanisms.

The LERs used in this analysis covered the period from early 1980 through 1992. The abstracts of approximately 300 LERs were identified via keyword search of the LER database maintained by Oak Ridge National Laboratory. Each of the reports generated by this search was individually reviewed; in cases where the applicability of a given report to a topic could not be reliably determined, the report was discarded. Of the 300 reports reviewed, 23 were ultimately retained as being applicable to power and distribution transformers of the type considered by this guideline. These reports were then categorized by component, failure mode, failure cause, and method of detection; categorization by manufacturer was not practical due to the lack of consistent component manufacturer data, as well as the low number of total reports. Analysis of the LERs (for each type of transformer) are included in Sections 3.6.3.1 through 3.6.3.3 below. It should be noted that the reporting requirements of 10 CFR 50.73 effectively dictate the method of detection of failures; hence, all failures reported in the LERs considered in this analysis were detected during transformer operations, and resulted in the failure of the equipment to perform its required function.

3.6.3.1 Liquid-Immersed Transformers

The data contained in the LER database described 18 events, from 16 separate units, related to liquid-immersed transformers. Of these 18 reports, 8 (44%) were related to failure of the primary/secondary winding insulation, and 5 (28%) were related to failure of the bushings. The remaining 5 reports were distributed among other transformer components. See Figure 3-24. Insufficient information was present in the reports to categorize failures as being applicable to either power or distribution units.

The only significant failure *mode* noted was degradation of organic insulation material (9 of 18 or 50%); 17% of the reports had unidentified modes. Only 7 of the 18 reports (39%) identified the underlying failure *cause*; 5 of these 7 reports listed moisture or dirt contamination as the reason for the transformer failure.

3.6.3.2 Dry-Type Transformers

The LER database contained 5 reports from 5 separate units related to dry-type transformers of the type evaluated in this guideline. All 5 reports (100%) were related to failure of the primary/secondary winding insulation. Degradation of organic insulating materials was the failure mode listed in each report. No common failure cause was indicated.

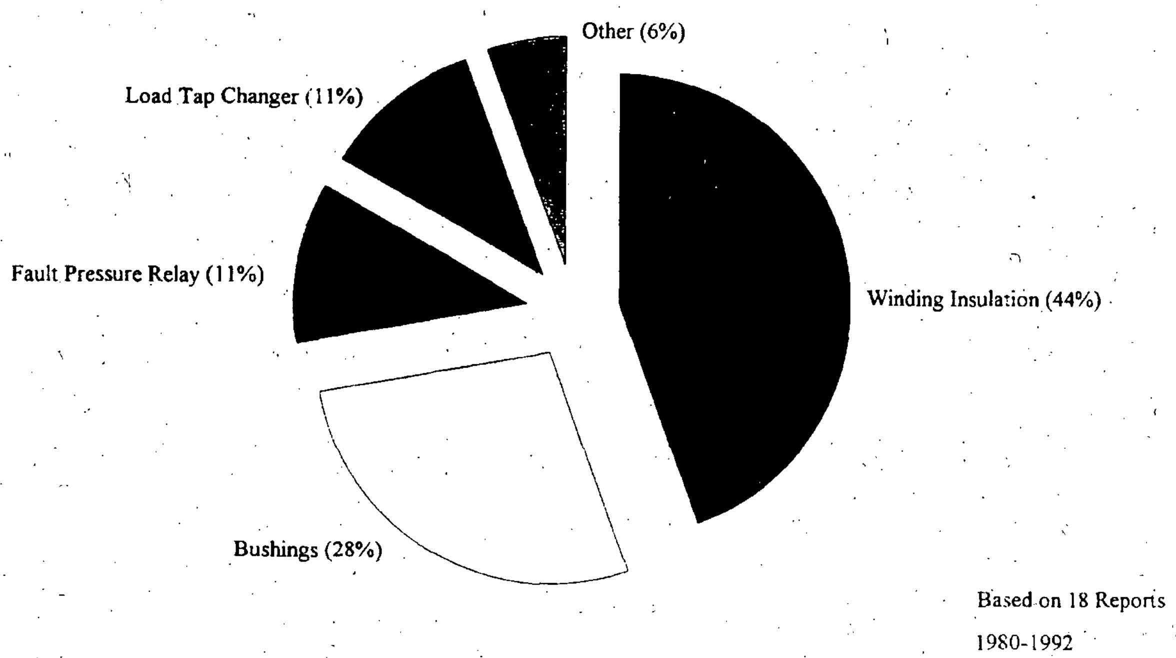

Figure 3-24. Licensee Event Reports, Liquid-Immersed Power and Distribution Transformers.

3.6.3.3 Conclusions from LER Review

Due to the extremely limited number of LERs applicable to power and distribution transformers of the type considered in this guideline, no real inferences can be made as to the relative reliability or probability of failure of individual transformer components. The following general observations were noted, however:

1. Failures of transformer primary and secondary winding insulation accounted for 57% (13 of 23) of the total number of failures reported. In contrast, winding insulation failures as reported in the NPRDS data were not a large part of the total. Sixty-one percent (14 of 23) of the reports listed degradation of organic insulation as the failure mode. (Note: The one additional insulation degradation was associated with a bushing as opposed to the windings).

2. For liquid-immersed transformers, bushing failure constituted a substantial portion of the reported failures (28%); failure modes for bushings included flashover due to contamination, degradation of insulation, and leakage.

3.6.4 Studies Providing Industry-Wide Operating Experience for Power and Distribution Transformers

3.6.4.1 EPRI NP-5002, "LWR Plant Life Extension"

EPRI NP-5002 [3.101] provided interim results from the pilot plant life extension studies conducted at Surry Unit 1 Pressurized Water Reactor (PWR) and Monticello Boiling Water Reactor (BWR)). These pilot studies were initiated in 1984 to identify specific research and development needs related to plant life extension and to serve as a basis for power system aging and life extension guidelines for the nuclear industry. The study considered many different plant components, including large station transformers. The evaluation of the Surry station transformers, funded by Virginia Power Company, EPRI, DOE, and the Westinghouse Owner's Group, assessed the impact of station transformers on the possibility of extended life operation for Surry Unit 1. The operating, maintenance, test, and outage records for the station transformers were reviewed and evaluated in order to identify degradation processes, assess new monitoring devices and techniques, and identify testing and maintenance methods effective at detecting incipient transformer failures. The findings and conclusions of the study (based on interim results) are discussed in the following paragraphs.

Exposure of Mineral Oil to Oxygen or Moisture

The presence of oxygen and moisture in transformer oil produces a variety of deleterious effects, such as localized reduction of dielectric strength and sludge formation. High moisture content, especially under overload conditions, may affect transformer life via vaporization and bubble formation. Sludge formation can result in plugging of oil flow passages throughout the windings, thereby reducing the heat removal capability of the system and further inducing hot-spot formation and its associated thermal deterioration.

External Short Circuits

Short circuit conditions generated external to the transformer can result in failure of the primary/secondary windings by a number of different mechanisms, including winding distortion, movement, and fracturing of brazed joints. These degradation mechanisms may ultimately lead to turn-to-turn winding shorts, localized hot-spots, or the generation of combustible gases due to deterioration of thermal insulation.

Overloading

Extended periods of overload will result in thermally-induced degradation of cellulose-based insulation components as well as decomposition of the insulating fluid (oil) which generates varying quantities of combustible gases.

Conclusions

Despite the existence of degradation mechanisms described above, no inherent limitation on the useful life of the transformers under evaluation was noted. In general, the service life of the transformer depends to a large degree on 1) the operational conditions to which the unit has been exposed (i.e., the number/duration of overloads, external fault events, etc.), and 2) the type and frequency of inspection and maintenance. However, despite the existence of maintenance and operations records, the remaining transformer useful life can not be accurately determined. Test data may be reviewed at regular intervals to determine if any abnormal rates of degradation (of the type described above) are being experienced. Signs of abnormal degradation may include:

- Reduction of insulating fluid dielectric strength
- Accumulation of moisture and other contaminants in the insulating fluid
- Formation of sludge
- Abnormal combustible gas levels
- Change in winding impedance, excitation current, or transformation ratio from factory test values (indicative of turn-to-turn shorts)
- Increased partial discharge or corona activity level (indicative of electrical breakdown of insulation)
- Abnormal noise/high sound level (indicative of loose and vibrating internal components)

3.6.4.2 NUREG/CR-3122, "Potentially Damaging Failure Modes of High- and Medium-Voltage Electrical Equipment"

NUREG/CR-3122 [3.102] considers the effects and circumstances surrounding electrical faults of transformers, switchgear, and other electrical components used in both nuclear and non-nuclear facilities. The scope was limited to equipment with voltage ratings of 4100 Vac and above. As part of the study, several sources of failure information were consulted. A total of 196 failures related to nuclear plant transformers were identified using the Nuclear Safety Information Center (NSIC) database. In addition to these reports, the study examined proceedings from the Doble Clients Annual Conference (an industry forum for issues and technology related to electrical components) for pertinent data. According to the Doble Conference data, numerous nuclear and non-nuclear liquid-immersed transformer failures (most of which were 13.8 kV and above) have occurred during each of the years 1975-1980; the study lists more than one-thousand failures (predominantly non-nuclear) during this time period. The NUREG also considers several significant transformer failure events recorded for main generator phase output transformers which failed at the North Anna station between 1980 and 1982. (See the discussion of NRC IE Information Notice 82-53 contained in Section 3.6.1.1 above for an analysis of the failures.)

The study concludes that failures of large transformers, although infrequent, usually result from a series of events such as abnormal loading, surges, and improper maintenance. The study also indicates that in general, transformer faults will mechanically damage only that equipment within the immediate physical vicinity of the unit; electrical damage, on the other hand, may be more widespread. Furthermore, primary to secondary winding arcing may expose components connected to the low voltage side of the transformer to potentially damaging voltages and currents. In many instances, incipient failures of transformer components can be detected via installed monitoring equipment or testing.

3.6.4.3 "Life Extension Considerations for Electrical Equipment in Light Water Reactors," by C. F. Bergeron and W. B. Dobson, Stone & Webster Engineering Corporation

This document examined considerations related to life extension of nuclear plant electrical power, instrumentation, and control equipment. Among the equipment evaluated in the study were large power (station) transformers of the liquid-immersed type. The paper relies primarily upon the results of the Surry and Monticello studies (see Section 3.6.4.1 above), as well as previous Stone & Webster Engineering Corporation (SWEC) work on fossil-fired stations as the basis for its conclusions.

Three types of life-limiting factors were considered in this evaluation; physical degradation, obsolescence, and equipment qualification. Physical degradation due to temperature was found to be the most life limiting factor. In addition to the evaluation of the degradation mechanisms, lifetime evaluations of each plant electrical component considered in the study (including transformers) were made. No principal age-related factors were found for the large station transformers studied; there was no apparent limitation noted on their useful life. [3.52]

3.6.5 Overall Conclusions Regarding Equipment Historical Performance

As discussed in the previous sections, five primary sources of information were used in this guideline to characterize liquid-immersed and dry-type transformer historical performance: (1) NRC Notices, Bulletins, Circulars, and Generic Letters, (2) INPO SERs, (3) NPRDS data, (4) LER data, and (5) industry information provided by previous analyses and reports relating to transformers. These sources each provide a somewhat different perspective on transformer component aging. Several limitations are inherent in any comparison of these results, stemming primarily from the variations in equipment types within the population, differing scope of equipment included, classification of failures, and criteria used in the analysis. Accordingly, no statistical inferences can be drawn concerning component failure probability or rate. Yet despite these limitations, several generic observations can be made.

Liquid-Immersed Transformers

1. In general, the larger liquid-immersed type transformers (i.e., startup or inter-bus) appear to be more problematic than the smaller liquid-immersed units, especially with respect to failures which affect the equipment's required function(s).

2. No one component appeared to be overly problematic. The component recording the highest overall instance of failure was the load tap changer, although the percentage of these failures was not significantly larger than that of other components.

3. Failure of the primary and secondary winding insulation does not appear to be a numerically large source of liquid-immersed transformer failures; failures of several other transformer components were equally or more frequent*. It should be noted, however, that insulation failure and dielectric breakdown in general had the most catastrophic and damaging results as well as the highest rate of lost functionality.

4. Contamination of the bushing exterior surface with moisture/and or foreign material has resulted in several cases of bushing flashover or grounding (thereby impacting the equipment's required function); this failure mode may vary in frequency of occurrence depending primarily upon the transformer's external operating environment. Internal bushing failures were rare except in cases of improper storage.

5. The majority of liquid-immersed transformer failures occur/are detected during operation; a substantial percentage of these failures result in the inability of the transformer to perform its required function for one reason or another. An exception to this were the smaller distribution-type liquid units, for which no instances of lost functionality (detected during operation) were noted.

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* This observation is based primarily on the data as represented by the NPRDS data base. Although a significant percentage of the failures described by Licensee Event Reports were related to winding insulation, this percentage was considered not to be representative of the overall equipment performance due to the reporting requirements imposed by 10 CFR 50.73.

Dry-Type Transformers

1. Failure of the primary and secondary winding appears to be the most significant failure mode for dry type transformers;. failure of cooling system components (primarily fans) also appears to be significant and could lead to winding failure.

2. Failure of dry-type transformer components (i.e., the winding insulation and cooling system) are most frequently detected during operation; they also often result in loss of function.

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4. APPLICABLE STRESSORS AND AGING MECHANISMS

4.1 Determination of Stressors Acting on Components

During operation, power and distribution transformers are exposed to a number of stressors that can lead to deterioration. These stressors may act individually or in combination with one another to produce an aging mechanism. The following discussion of stressors is provided to facilitate development of the discussion of aging mechanisms and age-related degradation that may occur in transformers. The potential stressors are:

- Temperature (ambient and internally generated)
- Voltage
- Mechanical and electrical cycling of auxiliary components
- Non-seismic vibration
- Radiation.

Although not directly producing stress, humidity, dirt, dust, and contamination may magnify the effects of the stresses acting on the transformer and can lead to deterioration of transformer components.

Temperature

Temperature exposure causes thermal deterioration of organic materials used in transformer subcomponents (such as insulators, structural members, and lubricants). Temperatures affecting transformers are associated with the ambient environment and temperature rise resulting from winding, core, and other losses. Elevated temperature existing in various portions of the transformer will cause gradual insulation deterioration; higher temperatures will result in more rapid degradation. Areas with elevated localized temperatures (hot spots) may develop in the windings as a result of blocked spaces or channels between windings, sharp bends in the winding, variations in magnetic flux density, and other factors. These hot spot temperatures can vary significantly from the average temperature of the winding, thereby causing accelerated degradation of any nearby winding insulation or other organic components. In addition, development of a high resistance connection in a primary current-carrying path can cause rapid deterioration of the surrounding insulating material due to ohmic heat generated. Heat generation by control circuits and other low-current components is considered negligible, except with respect to individual components whose temperature may be substantially elevated by internal heat production (such as coils of continuously energized relays).

Temperature effects may be mitigated in varying degrees by the cooling systems serving the transformer; this is based on such factors as the effectiveness of the cooling system, the existence/location of any hot spots, and ambient conditions. Generally, the ambient temperature surrounding indoor transformers is controlled between 21°C [70°F] and 29°C [85°F] and does not reach the 40°C [104°F] normal temperature limit assumed in transformer design and manufacturing standards. Transformers located outside may be subjected to more extreme temperature conditions (such as sustained periods of high temperature resulting from ambient/solar radiation, or sub-zero temperatures). Large power transformers used at nuclear power plants (such as start-up transformers) are frequently located in outdoor areas having potentially severe environmental factors. (See Section 3.5.2 for a discussion of these environments). Smaller power transformers and distribution transformers are generally placed indoors, and hence are not subject to such severe conditions.

Voltage and Current

Stressors associated with the electrical functions of transformer components may also lead to age-related degradation. Electrical stressors are caused either by extreme voltage gradients from over-voltage transients, spikes, and fault interruption, or continuous energization at normal voltage levels.

Fault currents and inductive surges/electrical transients can cause stressors which contribute to insulation breakdown and winding/core dislocation. When an electrical pulse is applied to a transformer, the voltage does not distribute uniformly throughout the windings. Based on the type and duration of pulse applied, portions of the winding insulation will be stressed more severely than others. These stressors can ultimately result in localized breakdown of the insulation causing turn-to-turn shorts, flashover to ground, or flashover between phases. Lightning strikes are especially degrading to transformers; lightning may generate voltages in excess of 500,000 volts and 200,000 amperes; hence outdoor transformers and other susceptible equipment must be provided with appropriate protective devices such as lightning arresters. Excessive voltages and currents can also lead to deterioration of the bushings and other insulating components, and provide a source of heat for thermal degradation.

Energization at normal design voltage levels can significantly stress transformer insulation over the long term; the amount and severity of this stress is determined primarily by the dielectric strength of the insulating material used. Dielectric strength is defined as the maximum potential gradient a given material can withstand without breakdown; this value is usually given in terms of the breakdown voltage divided by the material thickness. The dielectric constant (or permittivity) is a measure of a material's ability to insulate against a potential gradient across it; it is a function of the sub-atomic composition of that material which varies with temperature, frequency, and several other factors. For a given potential gradient, the voltage drop across each of the materials interposed between that gradient will vary inversely with the material's dielectric constant; the highest fraction of voltage drop will occur across the material of lowest dielectric constant. Hence materials with lower dielectric constants will usually be limiting in terms of the overall effective dielectric strength of the insulation system. Gas (or air) entrained in the insulating fluid of a transformer is of particular concern in that the dielectric constant of the gas is low in relation to the surrounding fluid; hence, the gas pocket will be stressed more highly than the fluid and other insulation while, at the same time, having a lower dielectric strength. This can cause localized ionization and breakdown at the gas pockets which degrades the insulating material. Similarly, impurities and contaminants, particularly in the presence of moisture, can greatly reduce the dielectric strength of an insulating system. Extreme care must be used both during manufacture and maintenance to minimize the introduction of contaminants into the insulating system.

In some dry-type transformers, voltage and humidity can affect solid insulation that is dirty or deteriorated; this can result in surface tracking paths between phase and ground, and adjacent phases. Moisture in the tracking path will allow larger leakage currents to flow. The leakage current flow will cause the moisture in the tracking path to evaporate; the leakage current will tend to remain constant such that the current density in the tracking path increases as moisture evaporates. This can result in localized burning of the insulation and ultimately insulation failure. Thermally deteriorated insulation, when exposed to humidity and dirt, may not only lose its surface insulating properties (in the form of surface current tracking), but may also lose its volumetric insulating properties. Thermally deteriorated insulation is most frequently brittle and prone to cracking. Leakage current, in addition to propagation across the surface of the insulation, may travel through the thickness of the insulation eventually resulting in flashover. Reasonable inspection and care of primary insulation systems in dry transformers should allow detection of surface and volumetric deterioration before it becomes severe.

Another phenomenon potentially affecting power and distribution transformers is internal electrostatic corona. This effect results from large potential gradients between conductors separated by air. A high electrostatic flux density results in ionization of the surrounding air; if the gradient is sufficiently large and the separation sufficiently small, complete dielectric breakdown (resulting in continuous discharge) may occur. Corona can occur between conducting surfaces internal to the transformer, such as between winding turns. Corona discharges are usually extinguished when the large voltage difference inducing its formation is reduced; however, the dielectric quality of organic materials may be reduced during each subsequent corona discharge. As a result, subsequent corona discharges will occur at progressively lower voltage levels. This process can continue until the corona extinction voltage level is less than the normal operating level, in which case the discharge will not extinguish and faulting will ultimately occur.

Currents may also be induced in transformer windings and components via geomagnetic interaction. Based on the intensity of the geomagnetic field present at a transformer's installed location, circulating currents of varying magnitude may be produced which can result in both increased losses and additional heat generation within the conductive elements of the transformer. This phenomenon has been identified as the cause of at least one main transformer failure at a commercial nuclear power plant; however, it is not expected to affect any significant portion of the total population of transformers covered by this guideline based on the specific environmental, design, and operational factors required for its occurrence. Accordingly, geomagnetically induced currents are not considered to result in age-related degradation and are therefore not considered further in this document.

Mechanical and Electrical Cycling

Cycling of transformer mechanical and electrical components such as oil pumps, fans, and load tap changers places stress on these components and may cause them to degrade or deteriorate with time. Cycling can vary significantly between individual transformer components, based primarily on their frequency of use. For instance, cooling system components may operate continuously or intermittently based on transformer load and ambient conditions; tap changers or pressure relief valves, on the other hand, may operate very infrequently (for example, only during shutdown conditions or periodic testing). Those components cycled or operated more frequently will experience significantly more wear and cyclic fatigue of mechanical internals, due to both mechanical stresses encountered during operation and any self-induced vibrational stresses such as those from rotating assemblies. Wear of moving parts can result in the loss of tolerances or loss of adjustment. Components requiring lubrication (pump motor or fan bearings) may also experience accelerated wear due to deteriorated or displaced lubricants.

Mechanical stress may also be placed on transformer components via continuous heating/cooling. Heating occurs as a result of core, winding, and other losses, as well as changes in ambient temperature and incident solar energy; heat generated in the unit is generally related to the operating load. Cooling results from heat removal by the cooling system, conduction convection/radiation by the transformer enclosure, variations in the ambient/solar conditions, and variations in load. As a result of these competing heating and cooling effects, the temperature of many transformer components (i.e., the insulation, windings, cooling system components, etc.) will fluctuate with time. This fluctuation creates thermal stress on these components in varying degrees, as determined by their material (thermal expansion coefficient) and design, and may eventually result in fatigue of these components. Cyclic fatigue may be manifested as stressing or cracking of both organic and inorganic (i.e., metallic) subcomponents.

Non-Seismic Vibration

Non-seismic vibration may also induce mechanical wear, fatigue cracking, loss of tolerances/adjustment, and loosening of subcomponents. Vibration will produce varying amounts of wear and stress over time depending on a number of factors such as the mass of the subcomponent, its material composition, the frequency of oscillation, the rigidity of its mounting, tolerances between it and other subcomponents, etc. Notches, fatigue cracks, loss of tolerances or calibration, or other manifestations of wear may eventually result from long-term exposure to this type of vibration. For components such as pumps and fans, the vibrations may be self-induced due to the operation of the motor or hydraulic effects. It should be noted that heavy external non-seismic vibration is not normally imposed on power and distribution transformers in that they are not usually located adjacent to large vibrational sources, and are usually mounted on vibration-resistant foundations. Additionally, many transformers use vibration-resistant mountings for their internal components (such as the core and coils assembly) to effectively isolate these components. However, self-induced vibration (AC "hum") of the core and windings may produce loosening or losses of critical tolerances in other components, potentially resulting in their failure.

Radiation

Radiation should not be a significant environmental factor for most transformers because the units are located either in plant areas that are accessible under most design basis conditions or outdoors. Ionizing radiation may reduce a material's dielectric strength and integrity by causing breakdown of insulation polymer chains, cracking of some plastics, and the formation of gas bubbles in oil. Yet for most power and distribution transformers, the maximum integrated normal and accident radiation doses would be expected well below 10^3 gray [10^5 rad] (up to sixty years), which would not cause significant deterioration of transformer materials. Any units used in areas with higher radiation doses (possibly small distribution transformers) are qualified by analyses or tests. Generally, the largest portion of the radiation dose is associated with an accident environment, and little or no radiation-induced damage is expected under normal conditions.

Contaminants/Moisture

Several types of degradation may result from exposure of the transformer to moisture and other contaminants. For example, intrusion of moisture or foreign substances through leaks in transformer components (such as degraded sample valves or relief valve seals) can contaminate the insulating fluid thereby resulting in a variety of deleterious effects ranging from accelerated sludge formation to dielectric breakdown and eventual transformer insulation failure. Dust, salt, and other airborne contaminants can accumulate on bushing exterior surfaces and, in conjunction with moisture or humidity, create the conditions that may lead to bushing flashover. Contaminants and moisture, in combination or acting independently, can result in deterioration of the transformer structural components; the housing may corrode and/or rust if exposed to contaminants and/or moisture such that the structural members and fasteners will weaken. In some instances, foreign matter may also affect the contact surfaces of relays, magnetic contactors, and other electrical components used within the transformer housing, potentially interfering with the performance of a component's required functions. Exposure to contaminants may degrade mechanical components via increased friction (leading to wear), stiffening or freezing of moving components, hardening and deterioration of lubricants, and embrittlement of non-metallic materials. [4.1]

Table 4-1 summarizes the stressors acting upon power and distribution transformers and indicates the aging mechanisms, types of degradation, and failure modes that may result from exposure to these stresses. [4.1, 4.2, 4.3, 4.4, 4.5, 4.6, 4.7, 4.8, 4.9, 4.10, 4.11]

Table 4-1. Stressors, Aging Mechanisms, Potential Failure Modes

(Note: Aging mechanisms, age-related degradations, and failure modes apply to both liquid and dry-type transformers unless otherwise noted.)

Stressor	Intensifiers	Aging Mechanism	Age-Related Degradation	Potential Failure Mode	Comments
Temperature	Acidity of insulating fluid	Thermal deterioration	Loss of mechanical and electrical properties of solid insulation	Dielectric breakdown; flashover	Generally a slow process
	Ohmic heating; winding and core losses	Thermal deterioration; cracking	Loss of dielectric strength of organic winding and electrical connection insulation	Dielectric breakdown; flashover	
	Contaminants	Thermal deterioration of lubricants	Binding and high friction; wear	Seized motor bearings, load tap changer components, valves, and enclosure door hinges	

Table 4-1. Stressors, Aging Mechanisms, Potential Failure Modes (Continued)

Stressor	Intensifiers	Aging Mechanism	Age-Related Degradation	Potential Failure Mode	Comments
Temperature (continued)	Moisture and contaminants; dielectric stress	Thermal decomposition of insulating fluid (liquid only)	Loss of dielectric strength; sludge and/or gas formation	Localized breakdown and gas formation	Detected by periodic sampling and analysis
Voltage	Contaminants; moisture	Accumulation of contaminants on bushing weather shield	Loss of surface insulating properties; surface tracking	External flashover of bushing between phase and ground	Accelerated in high dust, salt, and moisture environments
	Gas pockets or other low dielectric contaminants	Degradation of insulating fluid (liquid only)	Fluid decomposition and deterioration; gas formation	Localized breakdown of insulating fluid; eventual flashover and possible explosion	Detected by periodic sampling and analysis
	Low dielectric strength contaminants (such as gas or particulates)	Ionization and corona breakdown	Degradation of insulating materials	Dielectric breakdown; flashover	
Current	External fault or surge conditions	Electromagnetic forces on conductors/core	Movement or dislocation of windings and/or core	Loss of spacing of windings; turn-to-turn shorts	Not significant at normal current levels
Mechanical and Electrical Cycling	Deteriorated lubricants in auxiliary components	High friction between moving parts	Wear	Binding of tap changer, pump, or fan motor bearings, and valves	Increases with increasing duty cycle
	Voltage; contaminants	Pitting or erosion of auxiliary device contact surfaces	Degradation of electrical components	Misoperation of load tap changer; loss of cooling components	Increases with number of make/break operations
Non-Seismic Vibration	Loose internal components	Cyclic wear/fatigue	Wear and possible cracking of components; loss of tolerances, misalignment	Binding; component deformation or breakage	

4.2 Determination of Applicable Aging Mechanisms

Aging mechanisms were identified by considering the effects of stressors on each transformer component (Section 4.1) and the operating experience of each component (Section 3.6). Those aging mechanisms considered to be significant are discussed in Section 4.2.1. Those aging mechanisms considered to be non-significant are discussed in Section 4.2.2. Those aging mechanisms that have not yet been experienced because equipment has not aged sufficiently (assuming current preventive maintenance will not prevent failure) are discussed in Section 5.4.2.

4.2.1 Significant Aging Mechanisms

An aging mechanism is significant when, if allowed to continue without detection or mitigation measures, it will cause the component or structure to lose its ability to perform its required function. The following text discusses each significant aging mechanism for both liquid-immersed and dry-type power and distribution transformers. For definitions of aging terminology, see Appendix A.

4.2.1.1 Metal Enclosure (Tank) and Cover

Significant aging mechanisms for the transformer enclosure are:

- material degradation
- deterioration of organic sealing components
- metal fatigue
- loss/over-torquing of fastening components

all leading to a potential loss of structural or leak-tight integrity.

The first aging mechanism, material degradation, can take various forms, including rust or corrosion of metal surfaces and physical damage to enclosure components. Many transformers (especially the larger units) are located outdoors and are therefore exposed to the extremes of temperature, humidity, wind, and solar exposure. Chipping, cracking, or peeling of the enclosure's protective coating exposes the metal allowing the formation of rust and corrosion (most enclosures are fabricated from low-alloy steel which is highly susceptible to this type of effect). Moisture (i.e., condensation) may collect in areas of lower relative temperature such as the interior of the tank, cover, and any external electrical enclosures, thereby facilitating the degradation of these materials.

The second aging mechanism, deterioration of organic components, can occur as gaskets or other organic seals used in the construction of the enclosure degrade due to exposure to heat, ultraviolet radiation, moisture, or chemicals, while under mechanical stress or compression. Polymeric seal materials embrittle and harden with age and exposure, and generally must be replaced periodically, depending on the specific conditions present in their service environment.

The third aging mechanism, metal fatigue, can result from cyclic vibrational or thermal stresses placed on the enclosure (such as repeated heatup and cooldown cycles, operation of cooling system pumps and fans, or ac-induced hum). This can affect areas of high local stress such as welds, tank edges, etc., resulting in tank leaks (oil or gas-filled units) and potentially a loss of structural integrity.

Loss of fastening components, although not a specific aging mechanism, can also degrade the structural integrity of the enclosure by weakening joints, flanges, and other sealing surfaces or allowing components mounted to the enclosure to vibrate excessively (such as fans or other motors). The loss of fastening components can be caused by equipment vibration during operation or result from improper maintenance techniques.

Because each of the aging mechanisms described above can result in a loss of the structural and/or leak-tight integrity of the transformer tank, they are considered significant for systems which rely on these types of integrity for their operation (i.e., liquid-immersed or sealed dry-type transformers). The most probable result of loss of structural integrity is tank leakage. Insulating fluids or gases may escape or contaminants may enter with the ultimate result of breakdown of the insulation.

4.2.1.2 Primary and Secondary Windings

The significant aging mechanisms for the primary and secondary windings and their electrical connections (in both liquid-immersed and dry-type transformers) are:

- degradation of organic insulating materials
- formation of localized hot spots
- loosening of the winding mounting system
- winding connection (conductor) failure

These mechanisms are discussed for each type of transformer in the following paragraphs. Insulation system aging mechanisms are discussed in Section 4.2.1.4 below.

Liquid-Immersed Transformer Windings

Degradation of organic insulating materials in liquid-immersed transformers occurs as a result of several influences, including exposure to heat, chemicals in the insulating fluid, as well as dielectric stress. Insulation systems in these transformers consist of both solid and liquid materials, each being susceptible to somewhat different aging mechanisms (see Section 4.2.1.3 below). Protective coatings on the windings themselves are subject to thermal degradation due to heating of the windings; these coatings, however, generally have no insulating function and are therefore not necessary for maintenance of the necessary dielectric strength between individual turns of the windings.

Localized high temperatures may occur in transformer windings as a result of poor insulating fluid flow (which acts to cool the windings) and high resistance areas of the winding due to sharp bends, variations in conductor diameter, or improperly made connections. These "hot spots" may have temperatures significantly above the average of the overall winding, and may induce accelerated degradation of surrounding organic materials. Poor insulating (cooling) fluid flow is generally the result of loss of separation between windings, either due to clogging by impurities (such as sludge formed by exposure of the fluid to oxygen), or physical movement of the winding or supports. High resistance portions of the winding related to variations in conductor diameter are rare in that design of the winding is such as to minimize these effects. However, high resistance connections between windings and leads have been documented.

Loosening of winding mounting system can result from shipping of the transformer, normal operation (vibration), fault-related movement, or maintenance. Materials used to support the windings and core may degrade with time (many are fabricated from solid insulating materials) or loosen thereby allowing movement of the windings in relation to one another or the core under inrush or fault conditions. Core-to-winding and winding-to-winding tolerances are critical to maintaining satisfactory dielectric strength, therefore movement of these components with respect to each other can result in dielectric breakdown and localized discharge.

Although not a specific aging mechanism per se, conductor damage will potentially result in the loss of transformer function. Failure of the winding conductor is generally the result of either a pre-existing manufacturing flaw in the winding, a poorly made electrical connection (such as a braze or crimp), or a severe electrical transient which results from either an internal or external stimulus (such as loss of conductor tolerances described above, or exposure to short-duration transients or surges). Short-duration voltage transients will not affect the windings uniformly. Initially, current will flow preferentially through the shunt capacitance near the line-end of the winding; this produces a substantial voltage drop in these portions of the winding. Additionally, oscillations occur in the windings which affect various portions of the winding and insulation system based on their frequency and characteristics. In general, liquid transformers are more able to withstand severe electrical transients (such as lightning strikes and surge impulse voltages) than their dry-type counterparts (discussed below); this is primarily due to the physical properties of the immersion fluid (as opposed to the insulating medium used in dry transformers).

Dry-Type Transformer Windings

Failure mechanisms for dry-type transformer windings are similar to those for the liquid-immersed units described above, with the exception that the windings are not cooled by insulating fluid; rather, these transformers use air/gas (either forced or natural circulation) or a solid insulating material (such as resin) to dissipate heat generated in the windings. Similar to liquid-immersed units, these transformers may suffer degradation of the winding insulation (and coating, if used) due to thermal degradation induced by the windings and the lack of cooling. Air passages may become plugged with dirt or other contaminants, thereby creating hot spots and their resulting high temperatures. Resin-encapsulated or other sealed windings generally are not subject to this type of degradation, as there are no air passages to become obstructed by foreign materials.

In addition to obstruction of air passages, reductions in the spacing between windings (such as those resulting from movement of the winding due to fault currents, vibration, etc.) can occur and elevate the dielectric stress placed on the insulation present in the gap; this elevated stress in turn increases the potential for dielectric breakdown/corona discharge. A similar phenomenon may occur in resin-encapsulated transformers, where voids (bubbles) present in the resin during formation create areas of low dielectric strength, thereby allowing corona discharge and possible failure with time.

Airborne chemical vapors (such as paint fumes, solvents, etc.) may also come in contact with the winding surfaces (coatings) and solid insulation, thereby resulting in contamination or deterioration of these substances. Contamination could result in a loss of surface insulating capabilities.

Degradation of winding conductor connections has been documented; IE Information Notice 83-37, "Transformer Failure Resulting From Degraded Internal Connection Cables," [4.12] describes a failure due to an in-rush current on a dry-type ITE 4160-/480-Vac transformer initiating major arcing in the transformer winding tap lug causing the transformer failure. The failure was attributed to improper assembly of transformer winding tap cables and long-term undiagnosed, heat-induced degradation. It was believed that the set screw, which attaches the cable to the barrel of the lug, was over-tightened during installation, which caused some of the aluminum stranded wire to break, thereby creating a high resistance joint. Arcing is thought to have started in the barrel of the lug as a result of the resistance joint. Long-term localized heating of the terminal lug over a period of time weakened and degraded the connection.

Winding loosening and misalignment has been documented; examination of several transformers experiencing sustained overload, fault, and surge conditions has indicated dislocation of the winding turns, solid insulation and spacers, and core. [4.6, 4.7]

Because the primary and secondary windings and their connections are essential to the continued operation of both liquid-immersed and dry-type transformers, the degradation mechanisms described above are considered significant.

4.2.1.3 Magnetic Core

The significant degradation mechanisms for the magnetic core are:

- loosening of the core mounting system
- core material embrittlement

Each of these may result in the inability of the transformer to perform its required function.

Loosening of the core can result from loosening of its mountings due to vibration, shock, or severe electrical transients. Impacts or shocks received during shipping or installation can cause movement of the core on its mountings. Forces induced on the core after installation during electrical transients (by virtue of the magnetic interaction of the core, the windings, any surrounding materials) can be substantial and can loosen or permanently dislocate the core from its initial position. Fault currents (on the order of 10 to 20 times the rated output current) can induce severe forces on the conductors and core, as can surges resulting from proximate lightning strikes. Wear or deterioration of the insulation once dislocation occurs may lead to sufficient insulation damage to allow electrical failure.

Core embrittlement occurs primarily in older cores as a result of the relatively high thermal exposure resulting from core and winding losses. This embrittlement can result in weakening or failure of the laminations by which individual core segments are held together, thereby potentially creating increased eddy currents and core losses. Although spontaneous core failure due to embrittlement was not noted in any of the documentation reviewed during preparation of this AMG, instances of core embrittlement encountered during repair/refurbishment have been noted. Newer cores appear less susceptible to this phenomenon due primarily to advances in manufacturing techniques, materials science, and reduced core losses (and therefore heat generated) in the newer cores. Because the core and its integrity are essential to the operation of the transformer, core loosening and embrittlement are considered significant.

4.2.1.4 Insulation System

Liquid-Immersed Transformer Insulation

Degradation of organic insulating materials in liquid-immersed transformers occurs as a result of several influences, including exposure to heat, chemicals in the insulating fluid, as well as dielectric stress. Insulation systems in these transformers consist of both solid and liquid materials, each being susceptible to somewhat different aging mechanisms. The most significant degradation mechanisms for the insulating fluid are:

- gaseous formation/dielectric breakdown
- particulate and/or moisture contamination
- high acidity
- oxidation (sludge formation)

The primary degradation mechanisms for solid insulation used in liquid transformers are:

- thermal decomposition of organic materials
- decomposition due to dielectric stress

Due to the importance of the insulating system to the operation of the transformers, these aging mechanisms are deemed significant.

Dielectric stress is produced in the insulating fluid as a result of the potential gradient across various portions of the windings and other components. Generally, the dielectric stress placed upon a material during operation of the transformer is related to its dielectric constant; materials with lower or reduced dielectric constants will experience an elevated stress as compared to other materials with higher constants. For example, gas pockets formed in the insulating fluid are exposed to substantially more dielectric stress than the surrounding insulating fluid; this may result in partial or localized breakdown of the dielectric capacity of the material (partial discharges) which may in turn produce other deleterious effects such as the formation of additional gaseous byproducts, decomposition of the surrounding insulating fluid, and ultimate failure of the insulation system.

Gaseous by-products formed from the breakdown of insulating fluids may include both combustible and non-combustible gases such as carbon monoxide, hydrogen, ethylene, and acetylene. During normal operation, liquid-filled transformers have small concentrations of these and other gases (especially if an inert gas pressurization system is used) dissolved in the insulating fluid. The transformer may experience no adverse effects under these conditions;

however, cooling of the transformer may result in a substantially lower pressure in the tank which may in turn allow additional gas in the insulating fluid to come out of solution, potentially forming pockets of low dielectric strength bubbles in the fluid. It should be noted that for liquid transformers equipped with inert gas systems, the formation of gas bubbles or pockets during cooldown is mitigated through the pressurization of the void space above the insulating fluid with inert gas.

Particulates, contaminants, and moisture introduced into the insulating fluid can result in a number of different effects. Particulates or contaminants entrained in the fluid will eventually be circulated through the winding interstitial regions; this may result in blockage of these passages leading to reduced localized heat dissipation or hot spots. Chemical contaminants in the insulating fluid may have adverse effects on the material properties (such as pH, viscosity, etc.) of the fluid which can in turn result in other adverse effects on transformer components over the long term. Water is especially damaging to the dielectric capability of the insulating fluid; any appreciable concentration may result in failure of the transformer during operation due to dielectric breakdown as described above. Transformer fluids (such as mineral oil) normally can maintain a small amount of water in solution (usually less than 10 ppm at 70°C [158°F]); at these levels there is little if any appreciable effect on the dielectric strength of the insulating fluid. However, increases in the amount of water in the fluid, whether in solution (by virtue of other substances in the fluid such as acids which increase the solubility of water in the fluid) or coalesced in pockets, may dramatically reduce the dielectric strength of the insulating system and result in partial discharge or complete dielectric breakdown.

High acidity in the insulating fluid can have a number of damaging consequences. As indicated above, the acidity of the fluid can affect its ability to maintain water in solution; higher acidity generally equates to more water capable of being held in solution and therefore reduced dielectric strength. High acidity also can affect the deterioration and decomposition of solid insulating materials used as supports and braces in liquid-immersed systems; higher acidity has been demonstrated to accelerate the rate of decomposition of various solid insulations thereby reducing their dielectric capability.

Exposure of the insulating fluid to oxygen (air) can lead to the formation of sludge (a highly viscous, tar-like substance) in the oil as a result of the chemical reaction of the oil with oxygen. This sludge can be damaging to the transformer in that it may block oil channels in the windings (creating hot spots) and reduce the efficiency of the cooling system in general. Dielectric properties associated with the sludge may also differ from those of the host insulating fluid. Various additives such as ditertiary butyl paracresol (DBPC) have been used to inhibit the formation of sludge in oil due to oxygen. Exposure to oxygen will also increase the acidity of the insulating fluid (see preceding paragraph).

Degradation of the insulating fluid in liquid-immersed transformers as described above has been extensively documented. For example, INPO SER 24-84 [4.13] describes the failure of several nuclear plant transformers resulting in fires. See Section 3.6.1 for additional details.

Dry-Type Transformer Insulation

The primary aging mechanisms for the insulation used in dry-type transformers are:

- thermal deterioration/dielectric breakdown

Depending on the configuration of the individual unit, air, inert gas, fluorogas, or resin may be used as the primary insulating substance. In addition, solid insulation used in the support or construction of the core and windings (usually fabricated from resins, mica, asbestos, etc.) and any coatings on the windings themselves (high temperature resins or enamels) will be subject to thermal degradation.

For air-insulated, air-cooled dry-type transformers, degradation of the insulation is less of a concern; free interchange of air provides the transformer with a limitless supply of new insulation. These units are, however, subject to contamination of the windings and interior surfaces with airborne dust and other contaminants entrained in the air (see Section 4.2.1.2. above). This can result in the fouling of airflow paths or closing of gaps causing localized hot spots or corona discharge sites that can result in degradation of the insulation. For sealed systems (including air, inert gas, fluorogas, and resin), the volume of insulating material is finite, and certain of these substances may be subject to thermal degradation. This is particularly true of solid resin-encapsulated transformers; the resin is in direct physical contact with the windings and core (heat source), thereby subjecting it to accelerated thermal aging. Sealed, gas-filled transformers may also develop leaks which allow escape of the insulating gas and possible intrusion of external contaminants.

Thermal deterioration of solid insulation in dry-type transformers has been documented; for example, NRC Information Notice 92-63, "Cracked Insulators in ASL Dry Type Transformers Manufactured by Westinghouse Electric Corporation," [4.14] addresses the cracking of high-voltage winding ceramic insulators on ASL Dry Type Power Center 4160/480 V 3-phase transformers manufactured by Westinghouse. IN 92-63 indicated that an insulator cracking could have a catastrophic effect on the structural integrity of the transformer. [4.1, 4.3, 4.4, 4.6, 4.7, 4.15, 4.16, 4.17, 4.18, 4.19, 4.20]

4.2.1.5 Bushings

Significant degradation mechanisms for bushings include:

- degradation of organic materials
- contamination of insulating surfaces
- deterioration/leakage of inert gas
- electrical connection loosening

Organic components used in bushings may include kraft paper condenser insulating layers (usually soaked in oil or other insulating fluid), various polymeric resins used as insulation, and rubber, asbestos, or composite gaskets used to seal the bushing against leakage or to seal the bushing against the tank. These materials may be subject to a variety of degradation mechanisms such as thermal aging, exposure to ultraviolet radiation (exposed components), exposure to insulating fluids and other chemicals, and exposure to moisture. Kraft paper insulation is normally designed to operate while impregnated with insulating oil; improper storage or handling of the bushings prior to installation may result in drying out of the paper which can dramatically reduce its dielectric capabilities. Gaskets and seals used in the construction of the bushing may degrade over time with exposure to the elements (humidity, ultraviolet radiation, etc.) as well as heat generated by the bushing conductor, transformer, and incident solar radiation. All organic materials used in the fabrication of the bushing are subject to thermal degradation from these heat sources.

Contamination of insulating surfaces appears to be a significant degradation mechanism for transformer bushings, especially for outdoor units. External protective components such as the porcelain rain shield can accumulate significant quantities of dirt, dust, salt, and other contaminants from the environment; these contaminants, alone or in conjunction with rain, spray, or condensing humidity conditions, can result in the formation of a conductive path (tracking) along the surface of the rain shield which eventually leads to flashover of the bushing.

Depending on the construction of the bushing, it may contain insulating fluid (typically oil), inert gas, or both. Oil in the bushing is not exposed to atmosphere (air in the free space above the oil in the bushing is usually displaced with a charge of inert gas), and is generally not subject to many of the same types of degradation that transformer insulating fluid is. Therefore, unless the bushing seals are damaged, the only applicable degradation mechanisms for bushing fluid are exposure to heat and dielectric stresses. Heat is produced by the conductor (located at the bushing center), as well as from external sources (solar radiation, conduction with the transformer tank, etc.). Dielectric stress results from the potential gradient created between the central conductor and other surfaces. No degradation of the inert gas charge (other than leakage as described in the following paragraph) has been identified.

Leakage of the insulating oil and/or inert gas charge may occur as the seals of the bushing degrade, or as the result of damage or other conditions. Leakage of the insulating fluid from the bushing will eventually result in dielectric breakdown between the bushing conductor and other surfaces on the interior of the bushing. Because the bushing oil reservoir is not connected to the main tank insulating fluid, there is a finite volume of oil in each oil filled bushing. Most of these bushings, however, have some provision for periodic measurement of the oil level (either by gauge, sight glass, or direct measurement) which assists in the detection of this problem. Signs of leakage may also be detected during routine visual inspections or testing.

Additionally, leakage of the inert gas charge and subsequent depressurization of the bushing interior may expose the bushing insulating fluid to various ambient conditions (such as oxygen, moisture, and other contaminants) which may accelerate the deterioration of the fluid; this effect is expected to be small unless there is a significant interchange between the bushing internal and external environments.

Loosening or weakening of the bushing electrical connections may result from improper strain or mechanical stress. Excessive strain on the connectors can deform connecting hardware or other portions of the bushing. Under extreme circumstances, this can result in failure of the connections or damage to other bushing components.

Bushing failure has been documented in several instances; accordingly, the aging mechanisms described above are considered significant. IE Information Notice 82-53, "Main Transformer Failures at the North Anna Nuclear Power Station," [4.21] describes four bushing to ground failures and suggests that the improper storage of the bushings was a significant contributing factor. Additionally, INPO SER 13-85 [4.22] describes several transformer insulator (bushing) phase-to-ground flashovers resulting from combinations of condensation, salt accumulation, dust, and chalk powder. [4.1, 4.3, 4.4, 4.19, 4.23, 4.24]

4.2.1.6 Cooling System

Liquid-Immersed Transformer Cooling Systems

Significant aging mechanisms associated with the cooling system are:

- wear and mechanical fatigue of the pump and fan bearings (motor and pump unit)
- wear and fatigue of the pump impeller/shaft assembly
- degradation of motor winding insulation
- electrical component degradation
- fouling of heat transfer surfaces

Wear and fatigue of the bearings associated with the insulating fluid pump(s) and cooling fan(s) occur as a result of the routine operation of these components. Bearings (such as thrust and journal bearings) are commonly used on both the driven unit (i.e., pump) and the driving motor (for fans these bearings are typically part of the motor); these bearings wear over time due to friction and other stresses placed on them. Bearing longevity is determined by several factors such as the type of bearing, type and frequency of lubrication, and service conditions; wear on bearings may be accelerated by such stresses as frequent motor starting and stopping, undue vibration or transverse/longitudinal load placed on the driven unit (such as an out-of-balance fan), and inadequate or degraded lubrication. In many cases, liquid-immersed transformer oil pumps are partially or totally immersed in the insulating fluid; this assists in the reduction of friction and wear of the bearings. Fan motor bearings may require periodic lubrication, although these are often sealed units.

Wear and fatigue of the pump impeller/shaft assembly may occur after extended periods in service; this generally takes the form of loss of shaft tolerances, vane wear, or pitting, and results in reduced pump efficiency and increased noise and vibration during operation.

Organic winding insulation used in motors of this type is subject to thermal aging similar to that of the transformer insulation system described in Section 4.2.1.4 above.

A variety of different electrical devices are used in the cooling systems of transformers, including fan and pump motor contactors, thermal overload relays, thermostatic sensors and switches, general purpose relays, fuses, and control wiring. In general, the aging mechanisms applicable to each component will depend on the type of component and its operating environment. Aging mechanisms for the these components are discussed in Section 4.2.1.10 below.

Another potential aging mechanism for liquid transformer cooling systems is fouling of heat transfer surfaces. Most of the larger liquid-filled units utilize some sort of radiator to dissipate heat generated in the insulating fluid; heat transfer surfaces (i.e., fins or tubes) on these components may become fouled with dirt, debris, or other materials such that either the surface is insulated or airflow around the surface is obstructed. This can be easily prevented by periodic inspection and cleaning of these components (see Section 5). [4.2, 4.4, 4.5, 4.19]

Dry-Type Transformer Cooling Systems

Aging mechanisms for dry-type transformers are:

- wear of the fan motor bearings
- degradation of fan motor winding insulation materials
- electrical component degradation

These aging mechanisms are analogous to those discussed for liquid-immersed transformers in the preceding paragraphs.

4.2.1.7 Oil Preservation and Sampling System

The aging mechanisms for the oil preservation and sampling system are:

- deterioration of organic and inorganic materials
- wear
- loss of component adjustment

The primary organic materials used in the oil and preservation systems include gaskets and seals used to maintain the leak-tight integrity of any preservation and sampling system components (such as piping, flanged connections, inert gas bottle connections, etc.), as well as the separation diaphragm or air cell (used in the modified conservator design). Exposure of these materials to elevated temperatures (such as those from the heated insulating fluid or from incident solar radiation) results in thermal degradation; this may also be exacerbated by exposure to moisture, chemical contaminants, and possibly ultraviolet radiation (exposed materials on outdoor transformers). The separation diaphragm used in conservator systems may also become permeable to gaseous diffusion with time such that it may allow appreciable exposure of the insulating fluid to oxygen and other airborne gases.

Material degradation of inorganic system components can occur due to exposure to the elements (sun, moisture, salts, etc.), normal operation, and damage from other external sources. For transformers located outdoors, exposed preservation and sampling system components such as the conservator tank, piping, and valves are susceptible to rust, corrosion, and exposure to ultraviolet radiation. Heat transferred to these components by the insulating liquid or solar radiation accelerates corrosion, as does exposure to moisture/high humidity. Additionally, paint or other protective coatings applied to these surfaces may eventually bubble, chip, or peel, exposing the underlying surface to corrosion.

Wear can occur in a number of preservation/sampling system components, including frequently operated sampling and isolation valves, fittings, and pressure regulating valves used to maintain gas pressure (inert gas design). Subcomponents susceptible to wear include valve stems, seats, and packing, as well as other mechanically operated devices or fittings. This can result in valve leakage or binding, and malfunction of the regulating valve(s).

Loss of adjustment can result in the improper operation of the inert gas pressure regulating system; generally, this system must be adjusted such that the lowest possible purge pressure (accounting for deadband and setpoint variance) does not overlap the highest possible charge pressure; this would result in rapidly emptying the inert gas supply used to pressurize the void space above the insulating fluid. Loss of the adjustment of regulating valves can result from wear of the valve internals, mechanical agitation or shock, and changes in the ambient environment. [4.1, 4.4, 4.19, 4.24]

4.2.1.8 Tap Changers

<u>Load Tap Changers</u>

Load tap changers are typically constructed of numerous different mechanical and electrical components such as motors, gears, contacts, contactors, relays, solid state devices, and braking assemblies. The primary aging mechanisms for tap changing devices are:

- wear of mechanical components
- deterioration/failure of electrical components
- degradation of organic insulating materials
- loss of adjustment of braking systems
- wear of main contact surfaces
- tap changer compartment leakage

Wear of tap changer mechanical components may occur as a result of normal operation as well as abnormal operation. The main power circuit components of a load tap changer components are mounted in a separate tank chamber and are immersed in insulating fluid, therefore requiring no lubrication. In some models, however, tap changer motors and other mechanical assemblies (such as the braking system) are located in a separate compartment and have greasable bearings which must be periodically lubricated in accordance with the manufacturer's requirements. Exposure of this lubricant to elevated temperatures generated by both the operation of the motor/assembly itself and external sources (such as the transformer windings) can result in the deterioration, hardening, and separation of the lubricant with time. This deterioration results in increased friction and therefore accelerated wear.

In addition to wear of the bearings and lubricated mechanisms, the braking assembly linings of the tap changer (where equipped) may also degrade with use due to friction. These linings utilize friction to accomplish braking of the mechanism, hence by design they will degrade with use. Wear due to friction is the only real degradation mechanism for these components. Brake lining materials may vary from transformer to transformer, and hence the wear characteristics may differ.

Based on the type of braking mechanism used, loss of adjustment may occur with time such that the effectiveness of the system is impaired. Generally, braking system effectiveness can be gauged by the torque required to turn the mechanism under braked and unbraked conditions. When properly adjusted, the brake will have minimum braking torque and still provide positive braking; an optimum setting uses less than half of the design torque of the system. This gives a considerable margin for adjustment as the linings wear. As the system is operated, frictional wear of the linings, along with vibration and other mechanical stresses placed on the components, can result in a loss of this adjustment.

Wear may also occur on the main contact surfaces due to the motion of the moving contacts in relation to the stationary contacts during normal tap changer operation. This wear is generally a function of the frequency of operation of the tap changer unit and load current levels, and may be significant for transformers with numerous or repeated use of the tap changer over the course of their installed lifetime.

Degradation may occur in any organic insulating materials used in the construction of the tap changer. These will include insulation used in the motor windings, insulators surrounding or mounted to the main contacts, and materials used in related electrical components such as relays, contactors, and wiring. Normally, the primary degrading influence on these materials is heat; thermal aging of organic insulating materials can reduce their dielectric as well as mechanical properties.

Electrical devices used in the load tap changing mechanism may include switches, relays, contactors, terminal blocks, breakers or interrupting devices, fuses, minor electrical components (such as resistors and capacitors), solid state components, and wiring. Degradation and aging mechanisms associated with these components are described in Section 4.2.1.10 below; a complete discussion is contained in Reference 4.2.

4.2.1.9 Protection and Monitoring Systems

As discussed in Section 3 of this guideline, numerous protection and monitoring devices are used in power and distribution transformers; the number and type of these devices installed on any given transformer depends on the rating of the equipment as well as its plant application. For the larger liquid-filled units, most if not all of the devices described are used in one form or another. In contrast, smaller dry units may have few or no built-in protective/monitoring components. Many of the devices are only applicable to the liquid type transformer; for example, a liquid level indicator would not be found on a dry system. Although the specific characteristics of individual protection and monitoring devices change from manufacturer to manufacturer, the general operating principles are often quite similar. Hence, the degradation discussed in the following paragraphs describe generic component aging mechanisms, and therefore must be considered in light of the individual application. [4.1, 4.4, 4.5, 4.19, 4.23]

Fault Pressure Relay

As described in Section 3.4, the fault (or sudden) pressure relay is used on liquid filled transformers to detect the pressure transients associated with internal faults. These faults generate rapid increases in pressure within the tank. The significant aging mechanism for these relays is degradation of organic seals and gaskets. Wear or failure of internal relay mechanical components (such as springs, bellows, rocker arms, etc.) and failure of relay internal electrical components (switch contacts, wiring terminations, etc.) are considered non-significant, and are discussed in Section 4.2.2 below.

Degradation of organic materials used to seal the relay (both internally and to its transformer tank mounting flange) occurs as a result of exposure to heated insulating fluid or solar radiation over long periods of time; sustained exposure to heat and/or sun will eventually embrittle and harden the gaskets such that leakage may occur. In many designs, the sensing bellows and upper relay components are isolated from the hot insulating fluid (there is essentially no flow through the upper bellows portion of the relay), thereby exposing the gaskets in these regions to lower temperatures. Many of the gasket materials are also specifically designed for extended operation in contact with transformer insulating fluids. However, constant exposure of the gasket, which seals the upper and lower chambers from one another to hot insulating fluid, may result in its eventual failure.

Pressure Relief Devices

Aging mechanisms for pressure relief devices are:

- relaxation of the compression springs
- deterioration of organic sealing gaskets

Only the latter is considered to be significant. See Section 4.2.2.4.

Degradation of the organic seals of the pressure relief device may have an impact on the operation of the transformer over the long term. Due primarily to thermal degradation, these seals may harden, embrittle, and otherwise degrade to the point where they are incapable of performing their sealing function. Under conditions where the internal tank pressure is higher than that of the ambient (such as during a fault), the contents of the transformer tank will leak outward through the degraded seal causing a loss of inert gas and possibly even insulating fluid. Given a leak, the flow of gas may be inward or outward depending on variations in atmospheric and tank pressures (tank pressure may increase upon heating of fluid from operations or solar radiation). If the leak is small, the loss of inert gas and fluid (if any) will be slow and therefore present no threat to transformer operation. However, under vacuum conditions (such as those which might be encountered in the sealed tank type systems), leakage through the seal would be inward, thereby potentially introducing contaminants (such as air, moisture, and particulates) into the transformer tank and insulating fluid. These contaminants could cause accelerated aging of the fluid and eventual dielectric breakdown as described in Section 4.2.1.4 above. Although it is expected that periodic fluid sampling would identify such contamination, the frequency of sampling may not be sufficient in all cases to mitigate the effects of substantial water or oxygen intrusion in a short period of time. For this reason, degradation of the pressure relief seals is considered significant for the sealed tank design.

Bushing Current Transformers

Bushing current transformers (BCTs) are relatively simple devices; the only significant aging mechanism applicable to these units is degradation of organic insulating materials used in the windings. By virtue of their location (normally circumferentially located around the bushing center conductor), they may be subject to somewhat elevated temperatures resulting from heat generated in the BCT windings and any heat generated by the bushing conductor (which acts as the primary winding) during operation. Cracking, hardening, and low insulation resistance may result from long-term thermal exposure. Thermal decomposition of cellulose insulation may also result in increased moisture content in the transformer fluid (coincident with increased carbon dioxide levels).

The output signal from the bushing current transformer may be used in a variety of capacities, such as protective relaying, load indication, or load simulation for hot spot temperature detectors. Bushing current transformers used in differential relay applications may induce tripping of the unit if the load current is sufficient to pick up the relay. Similarly, since temperature indicators may by used to trip the unit in the event of a high temperature signal, failure of the bushing current transformer supplying one of these temperature instruments may potentially impact the required function of the transformer. In some cases, failure of the BCT will simply remove the input used to simulate the heat under load, and therefore will be unlikely to initiate a protective action upon failure. However, this mode of failure may also provide an erroneously low hot spot temperature indication, which may mask an actual high temperature condition. In other cases, shorting of the secondary windings may increase the current output of the transformer, giving an erroneously high temperature reading and thereby potentially tripping the transformer. Based on the these possible failure modes, degradation of the bushing current transformer winding insulation is considered significant.

Temperature Indicators

The significant failure mechanism postulated for the bourdon tube-type temperature indicator is failure of the hot spot heating coil element.

Failure of the hot spot heating coil element may occur as the element degrades due to exposure to temperatures generated during operation.. As previously noted, output from the bushing current transformer is used to generate a temperature rise in the hot spot detector probe which is proportional to the load on the transformer. This is accomplished via current passed through the coil which surrounds the temperature sensor. The metal coil is continually exposed to elevated temperature. Repeated heating and cooling of the element due to load variation induces thermal stresses which may eventually result in open-circuit failure of the element. Accordingly, the peak temperatures to which the element is exposed as well as the magnitude and frequency of load (and therefore temperature) variation are factors which can affect the longevity of the element. It should be noted that failure of the element as described will not directly affect the required function of the transformer; no automatic protective function or trip will occur as a result of low temperature. However, because failure of the coil will produce erroneous temperature readings (low), potentially damaging temperature conditions in the transformer may be masked. Therefore, failure of the element is deemed to be significant. In the event of suspected heater element failure, other temperature monitoring devices installed in the transformer can be used to verify the correct operation of the hot spot detector.

Fault Gas Monitor

The fault gas monitor's function is to detect concentrations of certain gases produced during fault conditions in the transformer. The monitor provides alarm, indication, and automatic protective action (in certain applications); hence, degradation or failure of the monitor may adversely impact the operation of the transformer from which it samples (see Section 3.6.2.1.1). Due to the complexity of the fault gas monitor system, numerous aging mechanisms can be postulated. Based on these considerations, no specific aging mechanism or failure mode analysis was performed for this system.

4.2.1.10 Electrical Auxiliary Devices

Electrical auxiliary devices such as molded case circuit breakers, magnetic contactors, thermal overload relays, switches, terminal blocks, fuses, and wiring may be used on power and distribution transformers for a variety of functions including control of cooling system pumps and/or fans, alarm and monitoring, and load tap changer operation. The use of these components in a given transformer depends on such factors as the size and rating of the unit and its function in the plant electrical distribution system. For example, large liquid-immersed transformers can be expected to have several electrical devices to support auxiliary systems (such as cooling, tap changing, and protection/monitoring); smaller dry-type transformers, which do not have elaborate auxiliary systems, may have only a few such devices. A complete discussion of these devices is contained in the Aging Management Guideline for Motor Control Centers. [4.2]

4.2.2 Non-significant Aging Mechanisms

4.2.2.1 Fault Pressure Relay

Wear or failure of fault pressure relay mechanical components may occur as a result of continual variations in transformer tank pressure with ambient temperature and load. Small pressure fluctuations are considered normal; as a result of these fluctuations the sensing apparatus (typically a bellows) of the relay will move in response, thereby wearing the internal components. Due to the fact that the bellows and internal are immersed in viscous fluid (such as insulating fluid or silicone oil), little wear of these components is expected. Components not immersed in these fluids (such as the rocker arm assembly) could be expected to experience a greater amount of wear; however, these components are typically only actuated upon a fault pressure condition, which is extremely infrequent. Accordingly, the aging mechanism of wear of internal fault pressure relay mechanical components is considered non-significant.

Failure of the fault pressure relay internal electrical devices such as the switch may result from repetitive relay actuations; due to the extremely low number of actuations expected over the course of the unit's installed life, these failures are not significant.

4.2.2.2 No-Load Tap Changers

There are two potential aging mechanisms for the no-load tap changer mechanism;

- commutator contact surface wear
- wear of mechanical components

None of these mechanisms is considered to be significant.

In contrast to the load tap changers described above, no-load tap changers are relatively simple in design and operation. Accordingly, many of the degradation mechanisms pertinent to load tap changers are not applicable. In addition, no-load tap changers are only operated infrequently (when the transformer is de-energized) and some of its constituent components may be immersed in the transformer insulating fluid; for these reasons, little wear or degradation of the no-load tap changer mechanism or contact surfaces is expected. Contact surface and mechanism wear are therefore considered non-significant. [4.4, 4.5, 4.19]

4.2.2.3 Resistance Temperature Detectors (RTD)

Depending on the environment in which the RTD is placed and the materials of its construction, the element may be subject to corrosion of the constituent metals (Fe, Cu, etc.). Additionally, vibration or shock may damage the more sensitive varieties of RTD (such as the glass-encased platinum resistor type). Most transformer RTDs are designed with increased immunity to these types of degradations and are not considered to be susceptible to these types of failure. RTDs may be used for actuation of protective measures such as tripping; failure could therefore preclude a required transformer function. However, due to the lack of identifiable aging mechanisms, these devices are considered highly reliable and not likely to significantly degrade with time or fail. [4.4]

4.2.2.4 Pressure Relief Devices

Pressure relief devices usually consist of diaphragm and spring arrangement which automatically resets upon reduction of the tank pressure below the actuation pressure; an external indicator and alarm switch may also be included. As the device ages, the compression springs (usually maintained in partial compression) tend to relax, thereby lowering the retarding force applied to the diaphragm. This may eventually result in a reduced set pressure and premature lifting of the relief device. This type of degradation is therefore conservative, in that overpressure conditions will be mitigated, albeit at a lower pressure. Severe relaxation of the spring may lead to operation of the relief during normal pressure transients; however, such severe deterioration would be expected to have no significant effect.

4.2.2.5 Thermocouples

Thermocouples may degrade over time based on their physical properties. For example, depending on the thermocouple's age, environmental exposure, and temperature exposure, the performance and accuracy of the unit will degrade over time. Greater age and higher exposed temperature both exacerbate the degradation of the device. Additionally, the potential generated by the junction is susceptible to several other external effects (such as temperature distribution along the connecting wires, strain, etc.). Generally, thermocouples are not used for continuous monitoring or automatic protective function initiation, therefore their aging is not considered significant to the operation of the transformer. [4.4].

4.2.2.6 Flow Indicator

Standard mechanical flow indicators are susceptible to wear of the internal moving components (such as vanes and flappers). Most transformers, however, use flow indicators on the oil systems (water cooled units, which are rarely used, may use them for indication of water flow); accordingly, these components are continuously lubricated. Additionally, not all of the flow capacity of the transformer is used at all times; hence some flow indicators may experience lower rates of wear due to the fact that the cooling loop or pump that they are monitoring is not in use. The flow indicator generally has no automatic protective function; rather, it actuates alarms or other indications for use by operations personnel. For these reasons, wear of the flow indicator is considered non-significant.

4.2.2.7 Liquid Level Indicator

Due to the relative simplicity and complete leak-tight integrity of the magnetic liquid level indicator design, no substantive aging mechanisms are postulated. Additionally, failure of the indicator would have no direct effect on the required function of the transformer.

4.2.2.9 Gas Detector

Bubble-type gas detecting devices, due to their simple designs, generally are not subject to significant degradation or aging. They are primarily employed to detect quantities of gaseous byproducts (i.e., bubbles) in the insulating fluid of liquid-immersed transformers; upon reaching a specified level, an electrical contact will close thereby actuating an alarm or warning device. There are few moving parts other than the indicator assembly and electrical switch contact (which is expected to be actuated very infrequently). No automatic protective functions are usually associated with these devices and their failure is of no direct consequence with regard to the operation of the transformer; periodic fluid and gas sampling would indicate actual problems if the gas detector failed. More sophisticated gas monitors or detectors (such as those capable of differentiating quantities of various gases present) may be used in the transformer; these are discussed in Section 4.2.1 above.

4.3 References

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4.22 INPO SER 13-85, "Loss of Offsite Power Due to Deposits and Condensation on Substation Insulators," 1985.

4.23 General Electric Co. Instruction Book GEK-48320, "Transformer Instructions," June 1982.

4.24 General Electric Co. Instruction Book GEK-36874, "Transformer Instructions," February 1974.

5. EFFECTIVE MANAGEMENT OF AGING MECHANISMS

5.1 Listing of Generic Elements of an "Effective" Aging Management Program

Methodologies have been established by the U.S. Nuclear Regulatory Commission for determining if a plant program is effective in detecting and mitigating the effects of aging. These criteria are provided in 10 CFR 54.21 [5.1], and state that an aging management program is effective if:

1. The program is documented, its implementing procedures are approved by onsite review committees, and it is implemented in accordance with plant administrative procedures, and

2. The program ensures identification and mitigation of age-related degradation unique to license renewal for systems and components important to license renewal, and

3. The program establishes specific acceptance criteria against which the need for corrective action is to be evaluated and requires timely corrective action to be taken when the acceptance criteria are not met.

Items 2 and 3 of this methodology criteria will be applied to the maintenance and surveillance techniques and programs discussed in Sections 5.2 and 5.3 to determine if the current programs are effective in mitigating the aging of power and distribution transformers and their components (see Section 5.4).

5.2 Common Maintenance and Surveillance Techniques and Programs Used for Transformers, Including Refurbishment and Replacement

Maintenance and surveillance of transformers is performed to ensure that the characteristics or attributes essential for operation are maintained. The following activities are commonly performed during operation, maintenance and surveillance of power and distribution transformers:

- Periodic observation of temperatures and levels
- Timely investigation and resolution of alarms
- Visual inspection
- Measurement of component properties (such as dielectric strength, oil viscosity, etc.)
- Cleaning
- Adjustments
- Lubrication

- Operability checks and testing
- Component replacement

Maintenance on transformers is either preventive or corrective in nature. Preventive maintenance is conducted based on either a given periodicity (every refueling cycle, for example) or the actual condition of the installed components (See Section 5.3.2 below). The scope of maintenance activities performed is generally a function of the periodicity of the maintenance; for example, frequent preventive maintenance (such as monthly transformer and bushing inspections) will be limited in scope as compared to maintenance conducted during a refueling outage. Obviously, de-energization of the equipment affords a much better opportunity to perform detailed examinations of many transformer components. Most plants* therefore perform more comprehensive examinations and testing of their large power and distribution transformers each refueling cycle or every few years, and sample insulating fluids either quarterly or semi-annually (or more frequently if conditions warrant). In addition to comprehensive inspection and maintenance during refueling outages, other preventive maintenance may be performed on the equipment on a more frequent basis (such as monthly or yearly) depending on the individual plant. Frequent rounds by operations personnel to observe temperatures and overall condition are also used to supplement these activities. It should be noted that most plants will rarely perform invasive internal inspections or disassemble transformers on a regular basis; these activities are usually scheduled as a result of component failure or other concern identified via the trending, fluid analysis, or thermography programs.

In contrast to the liquid-immersed units, usually only a portion (for example, one-quarter to one-third) of the dry-type transformers are examined or otherwise maintained during any given maintenance cycle. Due to the relative simplicity of the dry units as compared to the larger liquid-immersed models, maintenance of these transformers is greatly simplified. This results in a 5-8 year interval for most smaller transformers.** Some plants choose to maintain their safety-related transformers each refueling period. Most plants employ time-based maintenance schedules, due primarily to the simplicity of administering such schedules, the plant and operating conditions necessary to perform such maintenance, and the lack of component degradation/failure information necessary to justify condition-based programs. In many cases, the preventive maintenance activities (especially of safety-related transformers) coincide with the refueling outages, when transformers and their components can be removed from service with less effect on the safety and operations of the plant.

Corrective maintenance occurs on an as-needed basis, usually as a result of component failure or some other deficiency noted by way of sampling or thermography; it is performed to

* Based on a sampling of maintenance organizations and procedures associated with several different nuclear plants.

** Maintenance intervals for safety-related and non-safety-related dry-type transformers vary from plant to plant, yet generally appear to fall within the range of 4-10 years. Some plants perform maintenance on all similar type transformers at a fixed interval (for example, every 5 years), while others use a rotating schedule which examines a portion of the total population each refueling cycle.

repair an in-service failure or mitigate the effects of an incipient failure. Simple troubleshooting and repair/replacement of the faulty component is dictated in most cases.

To more comprehensively describe the maintenance and surveillance techniques commonly used to maintain transformers, vendor and utility maintenance procedures from a number of different sources were reviewed. In addition, personnel from appropriate plant maintenance organizations were contacted for additional insight on maintenance practices employed for each of the varying types of transformer. The results of these investigations follow. Common maintenance and surveillance techniques are discussed for each component. Note that certain subsections and discussions apply to specific types of transformers and components; for example, the discussion of oil preservation systems does not apply to dry-type transformers, and so forth.

5.2.1 Transformer Tank and Enclosure

The common maintenance practices currently used to maintain the tank components and fittings are visual inspection, cleaning and vacuuming, lubrication, pressure testing of tank, component replacement, and verification of the tightness of components. The visual inspection performed helps manage one of the enclosure aging mechanisms: material degradation. Visual inspection for rust/corrosion, leaks, and loose or broken parts assures the structural integrity of the enclosure by identifying degradation before it significantly weakens the metal housing components. Cleaning of the transformer structure and compartments is also performed. Mechanical fittings (such as hinges, etc.) are inspected and lubricated as necessary. Door gaskets and seals are also inspected for deterioration and signs of leakage.

Visual inspection and weld repair manage a second tank aging mechanism; metal fatigue. Cracked or broken parts and leaking seams or welds may be indicative of metal fatigue; this type of deterioration can affect tank structural and leak-tight integrity. Although metal fatigue generally cannot be prevented (except by periodic replacement of susceptible components), its effects can be mitigated through early detection and component replacement/repair. Weld repair is a common practice used on metal transformer tanks (as well as other components such as radiators and pipes) to correct cracked or broken welds; it basically involves either reforming the defective weld in place or applying a patch (usually used for large defects only). Conditions necessary to support weld repair will vary based on the location and magnitude of the crack; some welds can be repaired with the transformer filled, whereas others will require partial or complete draining of the tank.

Pressure testing of the tank enclosure may be conducted upon initial installation or upon restoration from major maintenance which may have violated tank pressure integrity. This helps manage the aging mechanisms of the gaskets and seals as well as weld fatigue and material degradation.

The final aging mechanism for the metal housing system, loss of fasteners, is managed by verification of the tightness (or torque) of anchoring and housing fasteners and replacement of lost or stripped fasteners. Verification of the tightness of components and replacement as required ensure that the enclosure components and fittings will remain tightly fastened to one another and also helps prevent leakage. [5.2, 5.3, 5.4, 5.5, 5.6, 5.7, 5.8, 5.9, 5.10, 5.11, 5.12]

5.2.2 Core

The maintenance practices related to transformer cores are the core-to-ground test (megger), and verification of core mounting system integrity and applicable tolerances.

The core-to-ground test is used in core-form transformers to check the core to ground insulation level. In most dry transformers, the core is grounded by a single strap which can be readily disconnected. In liquid units, tank entry is usually required, and core testing would be performed only at time of construction or after significant internal repairs. Low resistance readings are indicative of foreign material between the core and the tank or other problems with the core insulation system, and would require correction prior to return to service.

Verification of the core mounting system integrity helps control loosening or dislocation of the core due to non-seismic vibration during normal operation or forces generated by external electrical transients such as faults. Critical tolerances and dimensions may be checked to ensure no movement of the core or windings has occurred. However, these practices are not usually used except during periods when the core and windings are completely accessible (i.e., major corrective maintenance or scheduled internal inspections). Core loosening is not a commonly expected condition. [5.13]

5.2.3 Primary and Secondary Windings

Common surveillance and maintenance practices currently used to maintain transformer primary and secondary windings are electrical testing, visual inspection, and cleaning.

Visual inspection of the windings and surrounding insulation of dry-type transformers helps manage material degradation of the windings and insulation. Cuts, abrasions, discoloration, or cracking of the winding insulation may indicate areas of potential or existing low dielectric strength. Additionally, the ends of the windings are inspected for loose or otherwise degraded insulation and support and bracing materials and adequacy of electrical connections. In many cases, the winding turns themselves are not exposed (i.e., they are surrounded by insulating layers of paper, resin, etc.) hence visual inspection of most portions of the winding is impossible. In liquid immersed units, the windings are immersed in the insulating fluid, and thus may not generally be viewed unless the unit is drained or disassembled.

The windings of dry-type units may also be checked for rigidity and proper alignment (if accessible) with respect to one another and the core; this helps manage misalignment and loosening of the windings due to normal vibration and exposure to any electrical transients which may have stressed the winding mountings or retainers.

Electrical tests performed on the windings of both liquid and dry transformers may include evaluation of the insulation resistance, winding ratio, and insulation power factor. Insulation resistance (megger) testing is performed in the field on each winding with the other winding grounded, and from one winding to another. This test indicates the condition of the winding insulation as well as the presence of any moisture. Transformer winding ratio (or turn ratio test) is used to verify the transformation ratio of the primary to secondary windings at all tap settings. Power factor testing is used to detect insulation degradation; it measures the real and reactive components present between the primary and secondary windings as well as each of the windings to ground. Generally speaking, a significant increase in the power factor (after correction for temperature) is indicative of substantial insulation degradation or the presence of moisture or other contamination. For most dry-type units, extensive electrical testing is only performed upon initial installation; insulation resistance testing is the primary periodic test used to verify winding condition. [5.2, 5.7, 5.13, 5.14, 5.15, 5.16, 5.17, 5.18, 5.19]

5.2.4 Insulation System

Liquid-Immersed

Common surveillance and maintenance practices currently used to monitor and maintain liquid transformer insulating fluids are sampling and analysis, purification, or replacement.

The scope of transformer insulating fluid testing generally depends on the type of fluid used as well as the size and/or functional importance of the unit being evaluated. Sampling and testing of the insulating fluid for large liquid-immersed power transformers may include tests for sludge, acidity (neutralization number), inhibitor content, combustible gas content, flash point, water content, viscosity, pour point, color, refractive index, specific optical dispersion, interfacial tension, resistivity, saponification (foaming), and corrosive sulfur content. This testing is normally conducted either quarterly, semi-annually, or after anomalous indications during operation and maintenance, or from thermographic analysis. The transformers are provided with sample valves that are used to fill special vials with insulating fluid. The fluid is then sent to either a utility or independent laboratory for evaluation. The volume of the samples is small in comparison with the transformer volume; therefore frequent makeup is not required to replace the fluid taken during sampling. Each analysis is used to detect various types of contamination or deterioration, thereby helping to identify degradation of the oil due to exposure to high winding temperatures, oxygen, dielectric stress, moisture, and contaminants. The nature of the findings derived from sampling indicates the type of problem and the most likely corrective action. For example, high moisture content could indicate in-leakage at the tank boundary. Identification and repair of the leak would be required and treatment of the fluid would be necessary. The resistance of oils to partial discharges is also commonly evaluated by tests which measure the amount of decomposition gas evolved under specified conditions.

Excessive water is especially damaging to transformer insulating fluids, as it may produce significant degradation of the dielectric strength of the insulation system. Water content (measured in parts per million) is evaluated to ensure excessive levels of water do not exist in the insulating fluid. It should also be noted, however, that some water content (generally a few ppm) is desirable in that it helps prevent embrittlement and degradation of organic materials (such as solid insulation) in contact with the insulating fluid.

Exposure of transformer fluid to oxygen or air will generally result in increased acidity and sludge formation due to oxidation. An inhibitor is normally added to the fluid to mitigate the effects of oxidation; insulating fluid inhibitor content is checked to assure adequate concentrations to assure that oxygen does not attack the fluid.

Decomposition of certain materials (such as oil and solid insulation) during normal operation or partial discharge conditions produces both combustible and non-combustible gases such as hydrogen, methane, carbon monoxide, carbon dioxide, as well as particulate contaminants. Analysis of dissolved gases in the insulating fluid or inert gas blanket is used as an effective means of detecting this decomposition. These tests may be performed periodically (via sampling) or continuously (via an installed gas analyzer or similar instrument).

Power factor testing of the insulating fluid is also commonly conducted; this is usually performed in the field using a special test apparatus designed to hold a small sample of the fluid. This test is used to detect increases in the power factor that indicate degradation and/or decomposition of the insulating fluid.

Visual inspection of the insulating fluid may be used to identify gross levels of contamination, water, or other impurities. Samples of the fluid taken during maintenance or for analysis may be viewed directly at the transformer site or sent to a testing facility for more comprehensive testing (as described above). Water, sludge, and other impurities may be visible directly to the naked eye if present in sufficient concentrations.

Industry experience has developed a system for classification for insulating fluids based on their degree of degradation:

Group I — Oil that is satisfactory for continued use.

Group II — Oil that requires only minor reconditioning for continued use.

Group III — Oils requiring reclamation or disposal.

Group IV — Oils suitable for disposal only.

Reconditioning is defined as the removal of water and solid contaminants from the fluid. Reclamation, on the other hand, is chemical treatment or other processes to remove byproducts of fluid deterioration. Mobile systems for reconditioning transformer insulating fluid may be brought to the location of large transformers; fluid from the transformers can be circulated through a series of filters and dryers in the system, or vacuum treated to remove gas and moisture. These devices are not used on a regular basis but rather upon indication of problems or following invasive work on the unit.

Based on the results of the analyses described above, various actions may be required. For fluids which exhibit excessive levels of contaminants, water, dissolved gases, or low dielectric breakdown voltage, several techniques are available to recondition the fluid to acceptable levels. These include purification via centrifuge, use of a blotter filter press (for small quantities of particles or contaminants), and spraying of the heated fluid into a vacuum chamber to remove water and volatile acids (vacuum dehydration). In the event that the degradation is more severe, reclamation techniques may be employed. These techniques generally involve the use of Fuller's earth, a naturally occurring clay which is used for its absorbency and ability to remove acids and other contaminants from the fluid. If necessary, the fluid may also be replaced with new fluid after purging the old fluid and cleaning the interior surfaces of the tank.

Because a large portion of the degradation occurring in liquid transformer insulating fluid is thermally induced, temperatures associated with the transformer are also monitored to ensure adequate cooling and to operation within normal parameters and to help detect transformer overloading. Sustained operation at elevated temperatures can also rapidly degrade any solid insulation used in the construction as well; therefore, temperature monitoring and control is an important element of maintenance programs.

In addition to the maintenance techniques described above, many plants trend parameters associated with the insulating fluid such as tank level, insulating fluid temperature, gas concentration, and water content. [5.2, 5.3, 5.4, 5.7, 5.13, 5.14, 5.15, 5.16, 5.20, 5.21, 5.22, 5.23, 5.24, 5.25, 5.26, 5.27]

Dry-Type Transformers

Common surveillance and maintenance practices currently used to maintain dry-type transformer insulation are visual inspection, insulation resistance testing, and cleaning.

Visual inspection of the windings is conducted similar to that for dry-type transformers described in Section 5.2.3 above.

Insulation resistance testing is conducted at some plants periodically to verify insulation resistance levels and detect the presence of gross amounts of foreign substances (such as moisture or contaminants). Normally, winding-to-winding and winding to ground readings are taken. In addition, high potential (hipot) testing may be conducted subsequent to the insulation resistance test. It should be noted that electrical testing of dry-type transformers may not be used as a means of preventive maintenance at all plants; some operators perform electrical testing only at installation or after significant maintenance activities on the transformer. This is especially true of the smaller, non-safety related dry units.

Cleaning is conducted to remove the accumulated dirt, grease, and other contaminants on the windings and insulation; dirt can impede airflow and reduce the heat transfer from the windings, and contaminants may deteriorate the surfaces of any organic insulation or coatings which they come in contact with. Air under vacuum or pressure is normally used to remove accumulated dirt and dust; this is supplemented with wiping of the windings with a dry cloth to remove grease or sludge deposits. Care must be taken in using compressed air to blow clean transformer windings. Some dusts are abrasive and forced air cleaning may incrementally erode winding insulation. [5.13, 5.14, 5.15, 5.28, 5.29, 5.30, 5.31, 5.32]

5.2.5 Bushings

Common maintenance practices currently used to maintain transformer bushings are visual inspection, power factor tests, and cleaning.

Visual inspection of the bushing detects any chipping, cracking, discoloration, or other degradation of the porcelain weather shield, as well as any leakage of the oil from the bushing. Dirt, moisture, and other contaminants (such as salt) accumulated on the weather shield can also be readily noted and removed. Electrical connections to the bushing are inspected as well to ensure adequate connection tightness. Inspection of the bushings need not always be conducted with the transformer de-energized; plants sometimes utilize binoculars or other means of viewing the components from a safe distance.

Power factor testing of the bushing is used to detect any degradation of the bushing insulating system and oil fill. With normal capacitance, the power factor is a direct indication of the power lost in the insulation. Normal bushing power factor readings are extremely low, therefore any substantial power factor reading is indicative of contamination or deterioration of the bushing insulation. These readings are also sensitive to distortion by external influences such as moisture or dirt accumulation on the weather shield, or the connection of external parts (conductors) to the bushing; care must be exercised during power factor testing to eliminate the effects of such external influences.

Bushing oil levels are also trended to detect any leakage of the bushing over time which may not otherwise be detected by visual inspection. In certain applications, provision exists for the addition of small quantities of oil to the bushing in the event of leakage. [5.2, 5.3, 5.4, 5.13, 5.33, 5.34, 5.35, 5.36]

5.2.6 Cooling System

Common liquid-immersed transformer cooling system components include fans, pumps, heat exchangers or radiators, tank surfaces, piping, valves, thermostatically controlled switching devices, as well as temperature and vibration monitoring equipment. The maintenance practices currently used to maintain these components are visual inspection, monitoring, component adjustments, lubrication, and cleaning.

Visual inspection for physical damage, dirt, corrosion, leakage, or other degradation is conducted both during scheduled maintenance and during normal operation. Air passages (radiator fins) on oil coolers are examined to ensure they are clear and free from dirt which may hinder heat transfer, and to verify no leakage of insulating fluid. Fans are verified to operate properly (in the correct direction) with no excessive temperature, noise, or vibration; fan blades are also cleaned as required. Fan guards should be secure, and fan motors are periodically lubricated (if necessary). Mounting hardware is checked to ensure that the components are securely affixed to their supports. Cooling system isolation valves are inspected, and any sources of system leakage (i.e., valve packing, gasketed joints, etc.) are adjusted or repaired as necessary. Fluid pump bearing monitors may also be used to remotely detect unusual pump vibration during operation, depending on the design and type of transformer.

External surfaces of cooling system components are cleaned to remove dirt and contaminants; steam cleaning may also be used to clean dirt and accumulation from various transformer surfaces. Any exposed surfaces are painted or otherwise treated to preclude degradation due to rust or corrosion. [5.2, 5.3, 5.4, 5.13, 5.37, 5.38, 5.39, 5.40, 5.41, 5.42]

5.2.7 Oil Preservation and Sampling System

The common maintenance practices currently used to maintain transformer oil preservation and sampling system are visual inspection, component adjustment, component repair/replacement, and cleaning.

Visual inspection of fluid preservation and sampling system components such as piping, valves, conservator tanks, and desiccant systems is used to manage degradation of these components due to rust, corrosion, cracking (fatigue), and wear. Exposed components are painted as required. Joints, flanges, and valves are inspected for signs of leakage due to deteriorated gaskets or worn parts. Painting is used to control rust and corrosion of exposed materials susceptible to these forms of degradation. Conservator tank air cell diaphragms are inspected for embrittlement, cracking or leakage which may be indicative of the need for replacement. (Note: Indication of air cell deterioration may also be present in the transformer fluid analysis; fluid analysis results consistent with exposure to air may be traceable to failure of the diaphragm).

Pressure regulating valves are periodically tested for functionality and adjusted; nitrogen cylinders associated with inert gas systems are monitored and recharged/replaced when necessary. Worn regulating valve components are also replaced or the valve removed and repaired.

In addition to the measures described above, trending of preservation and sampling system parameters are often conducted; these parameters include transformer gas pressure, nitrogen bottle pressure (as applicable), and ambient temperature/pressure. [5.2, 5.3, 5.4, 5.13, 5.43, 5.44, 5.45]

5.2.8 Tap Changers

Common maintenance practices currently used to maintain transformer tap changer assemblies are visual inspection, component adjustment, fluid sampling, and cleaning. With many transformer designs, access to the tap changer components located within the enclosure (tank compartment) is usually restricted to those times when the enclosure is open for other reasons (such as corrective maintenance or scheduled internal inspection). In some cases the tap changer compartment must be filled under vacuum similar to the main tank. Electrical and mechanical tap changer components outside the tank/tap changer compartment, however, are usually readily accessible for inspection and maintenance.

Tap changer moving and fixed contacts are inspected for signs of wear. Contact surfaces of electrical components (such as relays and contactors) are inspected for signs of burning. Contact armature mechanisms are verified to operate freely. Degraded contact surfaces are polished or burnished as required and contact tolerances are re-adjusted. Tap changer brake linings are inspected for wear and adequate remaining shoe thickness; the braking mechanism is adjusted as necessary to ensure adequate brake operation (see Section 4.2.1.8 for additional information regarding brake adjustment).

Sampling of the fluid contained in the load tap changer (LTC) compartment is conducted in addition to sampling of the main tank insulating fluid; these volumes are typically separated and subject to somewhat different operating conditions. Reduced dielectric and increased power factor are usually the primary indicators of LTC fluid deterioration. Additionally, high ethylene levels in the LTC compartment fluid is also considered an indicator of hot spots in the LTC itself.

Although not part of the tap changer mechanism, tap changer compartment pressure relief valves are also manually verified to be operable. Any screens or filters are also inspected for signs of clogging or debris which might impede pressure relief. Care must also be taken during painting to ensure the valve is not inadvertently painted shut. [5.2, 5.3, 5.4, 5.13, 5.46]

5.2.9 Protection and Monitoring Devices

Fault Pressure Relay

Common maintenance practices currently used to maintain transformer fault pressure relays are visual inspection and functional testing.

Visual inspection of the fault pressure relay is used to detect damage or degradation of relay components, seals, and gaskets, as well as leakage. Functional testing is employed to verify the operation of the relay(s) under fault pressure conditions. This functional testing generally involves connection of an external pressure test rig to various ports on the relay which allow the application of pressure to the internal bellows assembly. [5.47, 5.48]

Pressure Relief Device

Common maintenance practices currently used to maintain transformer pressure relief devices are visual inspection and functional testing.

Visual inspection helps control degradation of the relief valve seals and gaskets; these components are inspected for dirt, cracking, or other conditions which could prevent the valve from sealing properly thereby potentially allowing moisture or external contaminants to penetrate into the tank and insulating fluid. Freedom of movement of the valve diaphragm is verified to ensure the valve will operate under actual high pressure conditions. Similarly, valves are inspected for any obstructions (such as debris or paint) which could inhibit the valve from operating or relieving at design capacity.

Depending on the scope of maintenance being conducted, the relief valve(s) may even be removed from the transformer tank to allow bench testing to verify their functionality; valves may be removed (and temporarily replaced with blind flanges) or "gagged" during tank pressure testing to allow sufficient buildup of tank pressure. Care must be exercised to preclude the introduction of any contaminants into the transformer when removing, testing, or replacing the pressure relief device. [5.13, 5.49]

Bushing Current Transformers

The maintenance techniques noted for bushing current transformers are visual inspection of the exterior of the bushing for signs of insulation cracking or other degradation, and insulation and coil resistance testing. These activities are conducted when the transformer is de-energized and opened for maintenance with the bushing(s) removed to allow access to the current transformers. [5.50]

Temperature Indicators, Liquid Level Indicator, and Gas Detector Relay

No maintenance techniques (other than periodic verification of instrument calibration and functionality) were noted for RTDs, thermocouples, or bourdon-tube type temperature detectors. [5.19, 5.26, 5.51, 5.52, 5.53, 5.54]

Fault Gas Monitor

Due to the complexity of the typical fault gas monitoring system and the relative infrequency of use in nuclear plant liquid-immersed transformers, maintenance techniques applied to these units were not considered as part of this AMG.

Electrical Components

Maintenance techniques applied to electrical components used in transformer auxiliary systems are analogous to those described in Reference 5.55. See Section 5 of this reference for additional information.

5.3 Other Common Maintenance and Surveillance Techniques and Programs

Other common maintenance and surveillance techniques applied to power and distribution transformers and their components include infrared thermography, replacement, rebuilding, and upgrading. These techniques are discussed in the following sections.

5.3.1 Infrared Thermography

Infrared thermography is a maintenance and surveillance technique used to detect and evaluate component heating. All materials radiate infrared energy. The hotter the component, the more energy radiated. Infrared detectors can sense infrared radiant energy and produce electrical signals proportional to the temperature of the targeted component. The instruments use optics to gather and focus energy from the targets onto infrared detectors. Instruments are currently available that have sensitivities on the order of ±0.1°C [±0.2°F] with rapid response times. Infrared detectors are available in two basic types: spot measuring and scanning. The spot measuring devices are pointed at a target area and provide either an analog or digital indication of the temperature of the target. The scanning devices provide a pictorial representation of the temperature of the area under observation. Variations in intensity or color of the image indicate the relative temperature. Some systems provide capability to store images for comparison to subsequent measurements or evaluation at a later time. Reference 5.56 provides a detailed description of the systems. The advantage of infrared thermography for use on power and distribution transformers is that temperatures can be observed and evaluated while the equipment is energized.

For transformers, spot measuring devices would be of limited use because manual scanning of components and tedious recording of individual component temperatures would be required. Scanning systems with recording capability are much easier to use because an area or component with elevated temperature can be readily compared to surrounding components and sections of the system to determine what is causing the increased temperature. If thermographic scans were performed previously, comparisons can be made and variations in thermal images can be evaluated to determine if these hotter areas are developing or changing. In transformers, abnormally hot electrical connections, bushings, and cooling system components could be indicative of problems either within the individual component or the transformer itself. For example, an excessively hot bushing might indicate a crimped, damaged or corroded internal electrical connection that could cause overheating leading to further damage or failure. Identifying such high temperature components could allow correction of the condition before significant damage occurred. At a minimum, more frequent observation could be performed of the suspect component to determine if the condition is stable or worsening.

Although infrared thermography is a valuable tool for evaluating the condition of components, it is not a panacea and should be used in conjunction with other techniques. Many aging mechanisms do not produce significant amounts of heat and may not be easily identified from thermal scans. For example, localized hot spots deep in the windings of the transformer would not be observable on the tank surface, but could be identified by fluid/gas analysis. Also, use of thermography requires a skilled operator who understands the technique, the materials being evaluated, and the equipment under observation. Distance from the target and the target's emittance, reflectance, orientation, and size all affect the thermal image. For example, a shiny surface will reflect infrared radiation from other areas, which can substantially affect results. Therefore, interpretation of results may require considerable skill or the operator may have to modify the target by covering it with a non-reflective material. If thermography is performed while a transformer is loaded in a manner other than normal (e.g., major loads out of service), the resulting evaluation may not indicate actual problems. Therefore, the operating status of the transformer needs to be considered when comparing and evaluating results.

Knowledge of thermography techniques, the types of aging mechanisms that could be indicated by heating, and combining thermography with other proven techniques such as visual inspection would make thermography a valuable tool for evaluating transformer condition. [5.56]

5.3.2 Replacement, Rebuilding, and Upgrade

Replacement, rebuilding, and upgrading are three alternative maintenance techniques that may be used to manage transformer aging. These techniques are described below.

Replacement

Replacement is used to control transformer aging in two primary situations; (1) individual component degradation or failure, and (2) catastrophic failure requiring replacement of the entire transformer. Replacement of individual components (such as pumps and fan motors) may be used when significant degradation or failure of those components occurs. Unit replacement, on the other hand, generally results from a major fault or explosion within the transformer; these failures are characterized by extensive damage to both the structure and components of the unit. Methods of dealing with each of these types of failures are described in the following paragraphs.

Non-catastrophic failure of transformer components occurs with substantially higher frequency in all classes of equipment as compared to catastrophic failure. In many cases, minor transformer components (such as fan motors, gaskets, seals, bushings, and small electrical components) which have failed are simply replaced as opposed to being repaired. This is due to a number of factors including the expense of replacement versus repair, the amenability of certain components to being repaired (i.e., relays and other components may be sealed thereby precluding maintenance or repair), and the importance of the required function provided by the component to the safe operation of the transformer. Critical components (such as the fault pressure relay) upon whose proper operation depend the functionality or safety of the transformer will likely be replaced in the event of malfunction or degradation, or may even be replaced periodically as a preventive measure. Other larger or longer-lived components (such as the tank and piping systems) will usually be repaired as necessary and therefore may be used throughout the life of the unit.

Due to the variety of different functions and operating conditions for components within a given transformer, degradation of components generally occurs at differing rates. For example, whereas a cooling pump may last the life of the transformer, a fan motor contactor may experience a substantial number of cycles over a certain period of time; accordingly, the contactor may fail more frequently than the pump. Components are therefore continually replaced throughout the life of the transformer based on their individual operating conditions and limitations. For many components (such as cooling fans and pumps), sufficient redundancy exists such that failure of one of these components can be tolerated with little or no adverse effect on transformer operation; replacement of the component is conducted after failure. Other components, however, either do not have sufficient redundancy or are of such importance to the operation of the transformer that their failure can not be tolerated. Components in this category include bushings and windings. Hence for these components, replacement or repair prior to failure is essential to ensure continued operation and limit the possibility of catastrophic failure.

In the event that the transformer suffers a catastrophic failure which heavily damages or destroys one or more major components of the unit (such as the tank, core, or windings), complete replacement of the transformer as a whole is usually dictated. The time required to repair or rebuild the transformer and the depth of damage will determine if replacement is required. Severe damage will tend to make repairs non cost-effective. Lesser damage may indicate that the transformer should be rebuilt and used as a spare.

Rebuilding

In cases of moderate damage or reduced capability, rebuilding of the transformer may be considered. Unlike simple component replacement described above, rebuilding seeks to restore the entire transformer to its original condition. Here, extensive disassembly and component replacement are conducted; although many of the structural and auxiliary components may be retained and repaired, new components are also fitted where necessary. Generally, the decision to rebuild a unit as opposed to simply repairing it depends on three considerations; the age of the transformer, the size of the transformer, and any existing or anticipated future needs for the equipment.

Very old transformers are usually not good candidates for rebuilding, due to their potentially high core and load losses, weakened or embrittled components, and the lack of availability of spare parts. Likewise, smaller transformers (below 5 MVA) may also prove to be cost-prohibitive to rebuild.

Upgrading

Another option available to the nuclear plant operator is transformer upgrading; this is a process by which the capability of the transformer (measured in terms of parameters such as temperature rating and load/core losses) is increased over that of its initial configuration during the rebuilding process. For example, during upgrading, the unit may be rewound with insulation rated to a higher temperature (i.e., 65°C [149°F] vs. 55°C [131°F]), windings may be replaced with larger, more efficient conductors, or the core itself may be replaced with one having substantially lower losses. Many plants rebuilding a failed transformer will also seek to upgrade to some degree; although the upgrading process is often significantly more expensive than simple rebuilding, the potential gains resulting from reduced losses and increased reliability may warrant the additional expenditure. [5.57]

5.4 Programs and Techniques Applied to Components

5.4.1 Evaluation of Current Programs

Section 5.1 lists the three criteria that determine if a maintenance program is effective in managing aging. With respect to Criterion 1, procedures from a number of power plants were reviewed. These reviews indicate that power and distribution transformer maintenance programs are documented. The maintenance of station transformers may be performed by different segments of the utility organization. The safety-related distribution transformers will be controlled by station procedures under the overview of the onsite review committee. However, the startup transformer maintenance may be controlled and performed by organizations outside of nuclear operations having experience with larger units.

With respect to Criterion 2, the maintenance procedures were reviewed to determine if they were effective in controlling and mitigating the effects of the aging mechanisms identified during the operating history review described in Section 3.6 and in Chapter 4. These procedures are described in Section 5.2. The results of this review are summarized in Table 5-1. The procedures required that inspection and maintenance activities be performed that would control each of the aging mechanisms identified in Section 4.2. The results of the operating history review described in Section 3.6 were evaluated to determine if further consideration or attention should be given to inspection and maintenance of certain components. In general, the review indicated that current maintenance programs using procedures that are consistent with Section 5.2 and Table 5-1 are effective in managing aging of power and distribution transformers. Conditions requiring plant-specific confirmation of effectiveness are described in Section 5.4.2.

Table 5-1. Common Maintenance and Surveillance Techniques

Component	Aging Mechanisms	Maintenance and Surveillance Techniques	Acceptance Criteria	Periodicity
Metal Enclosure (Tank) and Cover(s)	Material degradation from corrosion	Visual inspection of enclosure components and hardware; cleaning of exterior and interior enclosure surfaces (where accessible); painting of rusted or corroded portions of structure		Note 1
	Deterioration of seals and gaskets	Visual inspection for embrittlement, cracking, or signs of fluid leakage; replacement as necessary		Note 1
	Metal fatigue	Visual inspection for metal cracking or deformed/broken components; leak testing of enclosure (liquid or sealed dry-type only); weld or patch repair of cracked welds or leaking joints as necessary	Pressure retention specification during pressure testing	Note 1; pressure testing/repair as required
	Loss of fastening components	Visual inspection for missing screws, nuts, washers, and other fastening components; replacement as necessary		Note 1
Primary and Secondary Windings	Degradation of organic supports and spacers	Visual inspection of spacers, supports, and other insulating materials; insulation resistance testing; power factor testing; gas and oil evaluation (liquid only)	Insulation resistance; insulating fluid power factor; insulating fluid gas content	Note 2
	Formation of localized high temperature areas (hot spots)	Monitoring of hot spot, top oil, and other temperature indications; sampling and analysis of transformer insulating fluid for indication of decomposition byproducts and gases (liquid only); purification or replacement of insulating fluid as required; cleaning of windings and insulation (dry-type)	Temperature limits on indicators, insulating fluid content limits	Note 1; sampling quarterly, semi-annually, or more frequently as required
	Loosening of winding mounting systems	Visual inspection of winding mounting system for loose or damaged components; measurement of critical winding tolerances	Winding design tolerances	Note 2
Magnetic Core	Winding (conductor) failure	Visual inspection for overheating or breaks in insulation/conductor; resistance and continuity testing	Winding resistance	Note 2
	Loosening of core mounting system	Visual inspection of core mounting; core-to-ground test; measurement of critical core/winding tolerances	Core design tolerances	Note 2

Table 5-1. Common Maintenance and Surveillance Techniques (Continued)

Component	Aging Mechanisms	Maintenance and Surveillance Techniques	Acceptance Criteria	Periodicity
Insulation System (liquid-immersed)	Dielectric breakdown of insulating fluid	Sampling and analysis for dielectric strength, power factor, water/impurity content, and combustible/non-combustible gases, as well as other analyses as applicable	Dielectric strength (breakdown voltage), power factor, water/impurity content, gas content; other criteria as applicable	Quarterly or semi-annual fluid sampling (or more frequently as required by analysis results or other indicia)
	Particulate and/or moisture contamination	Visual inspection of insulating fluid for signs of impurities or water; dielectric strength and power factor testing; laboratory analysis for water content	Dielectric strength (breakdown voltage), power factor	Same as above
	High acidity	Sampling and laboratory analysis (neutralization number)	Neutralization number	Same as above
	Oxidation and sludge formation	Visual inspection of insulating fluid; laboratory analysis for sludge and inhibitor content; maintenance of seals and air-tight integrity of tank and oil preservation system components	Sludge and inhibitor content	Same as above
(dry-type)	Thermal deterioration of organic materials	Insulation resistance and power factor testing		Note 3
(liquid and dry)	Thermal deterioration of solid organic insulating materials	Load and temperature control; acidity monitoring; gas and oil evaluation; analysis of insulating fluid for decomposition byproducts; visual inspection for discoloration, cracking; insulation resistance testing	Insulating fluid gas content and acidity	Quarterly or semi-annual fluid sampling (or more frequently as required); visual inspection of solid insulation only conducted during invasive procedure
Bushings	Degradation of organic materials	Power factor and capacitance testing	Power factor, capacitance	Every refueling cycle; during other maintenance when unit de-energized (as required)

Table 5-1. Common Maintenance and Surveillance Techniques (Continued)

Component	Aging Mechanisms	Maintenance and Surveillance Techniques	Acceptance Criteria	Periodicity
Bushings (continued)	Contamination or deterioration of porcelain exterior surfaces	Visual inspection for dust, salt, contamination, cracking, streaking, discoloration, or chipping of porcelain insulator; cleaning, coating, or replacement as necessary		Note 1
	Deterioration and leakage of oil/inert gas	Visual inspection for indications of leakage; verification of bushing oil level; replacement of gaskets/seals as required	Bushing oil level	Note 1
	Electrical connection damage or loosening	Verification of connection tightness and check for excessive strain	Fastener torque; strain	Every refueling cycle; during other maintenance when unit de-energized (as required)
Cooling System	Wear/fatigue of the pump and fan motor bearings, shaft, and impeller	Visual inspection of fan motor, housing; and rotating assembly for loose/missing parts or other damage; inspection of pump impeller for cracking, pitting or erosion; verification of normal fan or pump operation (no vibration, abnormal noise, overheating, etc.); periodic lubrication; bearing or component replacement as required		Note 1
	Degradation of motor winding and lead insulation	Winding insulation resistance testing; replacement of motor and/or leads as required	Insulation resistance, absence of cracks in insulation of cable	As required
	Electrical auxiliary component degradation	Visual inspection and cleaning of contactor mechanisms, contact surfaces, wiring and terminations, and other minor electrical components; functionality testing; replacement as necessary	Functionality of component	As required
Fluid Preservation and Sampling System (liquid only)	Fouling of heat transfer surfaces	Visual inspection and cleaning of radiator fins, tubes, and other heat transfer surfaces; verification of adequate air or cooling water flow	Transformer temperature limits	Note 1

Table 5-1. Common Maintenance and Surveillance Techniques (Continued)

Component	Aging Mechanisms	Maintenance and Surveillance Techniques	Acceptance Criteria	Periodicity
Fluid Preservation and Sampling System (continued)	Deterioration of organic and inorganic materials	Visual inspection of piping, valves, coolers, and welded seams for cracking, rust, corrosion, or other deterioration; cleaning and painting; functionality testing; replacement as required	Functionality of components	Note 1
	Wear of mechanical components	Inspection for component looseness or loss of adjustment; measurement and adjustment of component tolerances; lubrication; replacement as required		Note 1
	Loss of component adjustment	Verification of proper pressure regulating valve setpoints and operation; cleaning and adjustment as required	Maintains pressure as required	As required
Tap Changers (Load Tap Changer; liquid only)	Wear of mechanical components	Verification of component tolerances and adjustment	Component tolerance/ adjustment specifications	Note 2
	Deterioration or failure of electrical components	Visual inspection and cleaning of tap changer electrical components and contact surfaces; electrical and functionality testing; replacement as necessary	Functionality of tested components; no significant degradation of contact surfaces	Note 2
	Degradation of organic insulating materials	Visual inspection of components for cracking or other loss of mechanical properties; insulation resistance testing	Insulation resistance	Note 2
	Loss of adjustment of braking systems	Visual inspection of brake linings for wear; verification of proper braking system adjustment and torque; replacement of brake linings when required	Proper brake function	Note 2
	Wear of main contact surfaces	Visual inspection of moving and stationary contact surfaces for wear or contamination; cleaning, reconditioning, or replacement as necessary		
	Tap changer compartment leakage	Visual inspection for leakage or deteriorated gaskets; verification of proper oil level	Adequate oil level	Note 1

Table 5-1. Common Maintenance and Surveillance Techniques (Continued)

Component	Aging Mechanisms	Maintenance and Surveillance Techniques	Acceptance Criteria	Periodicity
Fault Pressure Relay (liquid only)	Degradation of organic seals and gaskets	Visual inspection for signs of leakage, cracking, or other gasket/seal degradation; functional testing		Note 1; functional testing as required
Bushing Current Transformers	Degradation of organic insulating materials	Insulation inspection; insulation resistance testing	Insulation resistance	Note 1
Pressure Relief Devices (liquid and sealed dry-type only)	Degradation of seals	Periodic testing for functionality; visual inspection for seal degradation	Relief valve functionality	Note 1
Temperature Indicators	Failure of hot spot heating coil element	Periodic verification of temperature sensor functionality and accuracy	Temperature sensor functionality	As required

Notes:

1. Conducted during routine operations or during scheduled maintenance or surveillance activities; periodicity varies.

2. Not a routine maintenance item; generally accomplished only during invasive maintenance procedures requiring disassembly, draining, and/or untanking.

3. Usually performed each refueling cycle on a rotating basis for larger dry-type transformers. Smaller units may only be tested during installation or after significant maintenance.

Figure 5-1 shows failures for liquid-immersed transformers of the type considered in this AMG (i.e., excluding main and unit auxiliary transformers) for the years 1981-92. All failures relating to liquid-immersed transformers for a given year were divided by the number of plants in operation during that year to obtain the number of failures per plant per year. This rate was also calculated for that subset of failures which were detected during plant operation and which resulted in preclusion of the transformer function. As shown in the figure, the highest failure rate observed was 0.17 failures per plant per year (1985); if extrapolated, this would result in approximately one liquid transformer component failure per plant every 6 years. The projected number of failures which would preclude transformer function would be even lower, on the order of approximately one failure per plant every 11 years. Failure rates for years other than 1985 are all less than 0.082 failures per plant per year, indicating one failure per plant every 12 years or more. Additionally, the overall trend in failure rate for this equipment does not appear to be increasing.

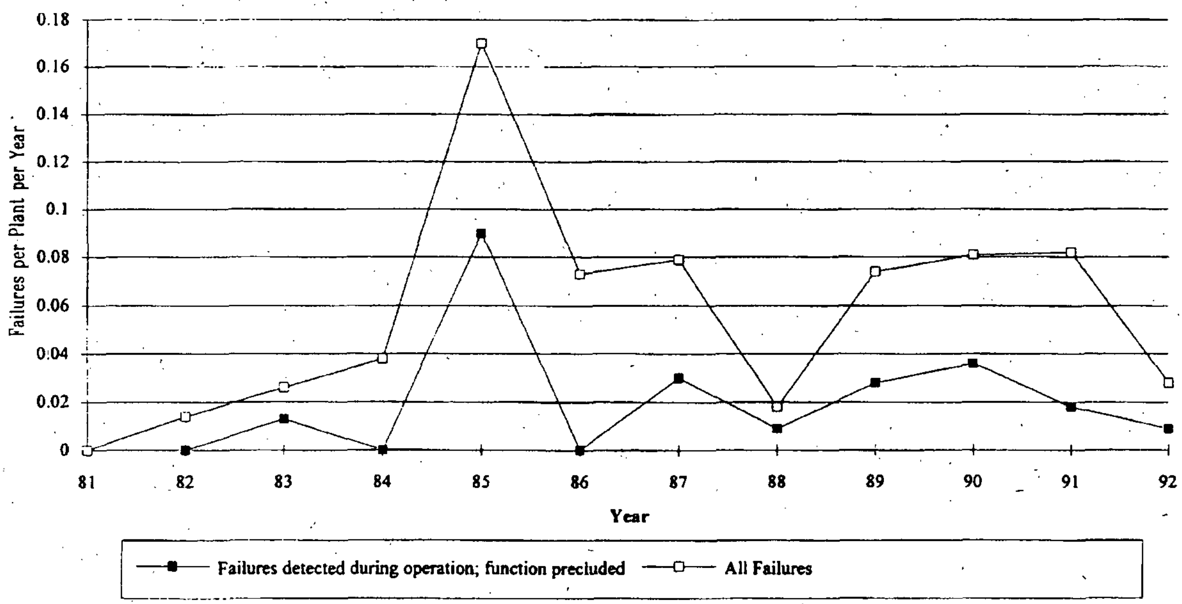

Figure 5-1. Liquid-Immersed Transformer* Failures by Year (NPRDS).

Figure 5-2 shows a similar analysis for dry-type transformers. Failure rates for these transformers were even lower than those noted for the liquid transformers (peak failure rates of approximately one failure per plant every 15 years, and one failure which precludes transformer function per plant every 27 years). Again, no increasing overall failure rate trend is discernable. (Note: The lower failure rates identified for the dry-type transformers may be in part related to the size of the population, which is considered to be substantially smaller than that of the liquid-immersed transformers).

It should be noted that no estimate of the population of transformers of the type covered by this AMG was made as part of this analysis; additionally, the fraction of the plant population reporting to NPRDS in a given year is not known. Therefore, the failure rate information derived above can not be relied upon as a foundation for Mean Time Between Failure (MTBF) or other similar analyses. However, even with substantial variations in the number of plants operating such equipment (or reporting associated failures), or in the fraction of actual failure events which are reported, the projected failure rate is still reasonably low. For example, increasing the number of liquid transformer failure reports by a factor of 2 (only 1 of every 2 events assumed to be reported to NPRDS) and decreasing the number of reporting plants by the same factor still only results in one liquid transformer-related failure per plant every 1.5 years and one failure which precludes transformer function per plant every 3 years.** Note also that most plants can be assumed to have more than one liquid-immersed transformer which falls within the scope of this AMG; therefore, these rates are likely to be extremely conservative.

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* Does not include Main or Unit Auxiliary Transformers.

** Based on the 1985 peak failure rate(s).

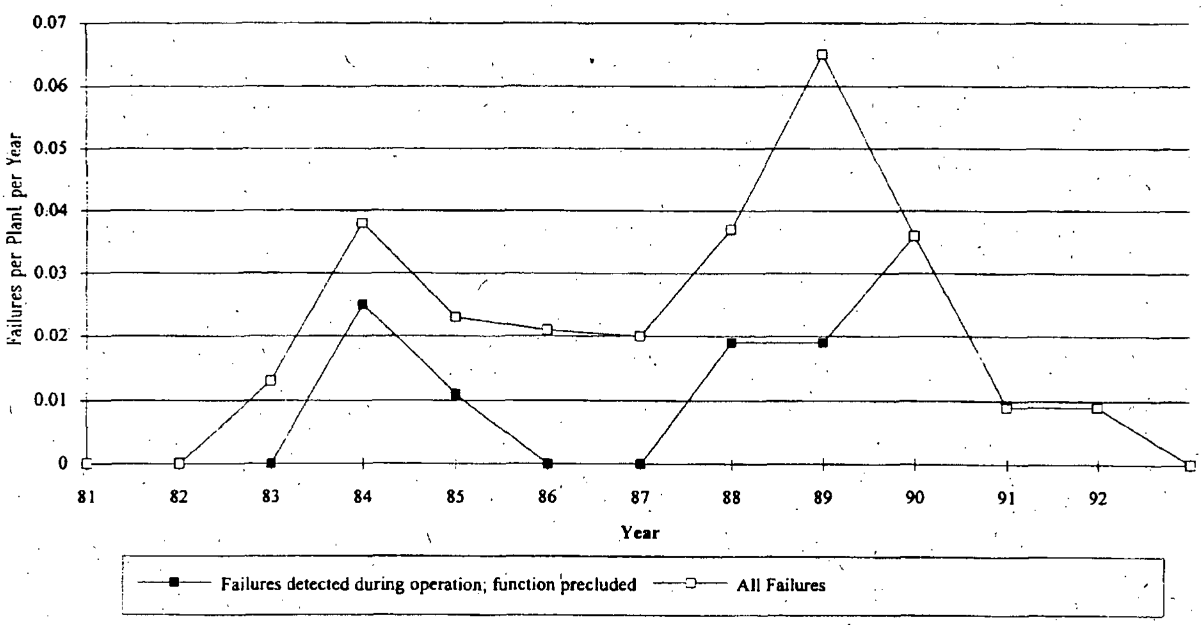

Figure 5-2. Dry-Type Transformer Failures by Year (NPRDS).

Based on the data discussed above, it is believed that maintenance practices employed during the period of evaluation were, in general, effective at managing the age-related degradation of both the liquid and dry-type transformers covered in this AMG.

Each maintenance procedure was also reviewed for compliance with Criterion 3 (which specifies the need for specific acceptance criteria and timely corrective action). Each procedure contains acceptance criteria against which the need for corrective action is to be evaluated and required timely corrective action to be taken when the acceptance criteria are not met. In Table 5-1, activities requiring tolerances and acceptance criteria to be contained in procedures are so indicated.

The review of the significant aging mechanisms versus established maintenance practices indicated that all significant aging mechanisms are considered and controlled with a limited number of potential exceptions that are discussed in Section 5.4.2. This conclusion is supported by the review of operating history that indicates few repetitive failures associated with any one specific transformer component for a given manufacturer's model line (or for all manufacturers collectively).

5.4.2 Potentially Significant Component/Aging Mechanism Combinations Not Addressed by Current Programs

Review of the aging mechanisms identified in the operational review contained in Section 3.6 and Section 4.2 in comparison with the transformer maintenance methodology verified that nearly all component/aging mechanism combinations are addressed by current programs. The following lists those cases where additional efforts appear to be necessary.

Conditions for a Fully Acceptable Program

If the transformer is located in a mild environment area (not subject to an elevated temperature/steam condition or elevated radiation levels under accident conditions), is in an area where temperatures do not exceed 40°C [104°F] for significant periods (or 30°C [86°F] average temperature for any 24-hour interval), is not subjected to abnormal electrical loading or severe transients, is not exposed to high external concentrations of dust or other contaminants, then maintenance and surveillance procedures that are consistent with those described in Section 5.2 and Table 5-1 will be effective in managing aging, with the following possible exceptions:

- Dielectric Breakdown of Insulating Fluid. Many of the more damaging failures (such as explosions and fires) occurred as a result of dielectric breakdown of the insulating fluid. This breakdown can be precipitated by various conditions such as moisture contamination and gaseous formation in the fluid (or accumulation of gases in the void space above the fluid), and may be detected by various types of laboratory and/or in-situ analysis.

- Bushing Flashover. Bushing contamination and subsequent flashover is due primarily to airborne dust and/or salt spray accumulation on exterior bushing surfaces acting in combination with rain or high humidity. Even low concentrations of dust and contaminants result in significant accumulations over time and can induce flashover when combined with moisture.

- Thermal Deterioration of Solid Insulation. Solid insulating components used in the construction of both liquid and dry-type transformers are subject to thermal deterioration; this deterioration is a function of the temperature to which it is exposed as well as the condition of the insulating fluid in which it is submerged (for liquid-immersed units).

As indicated above, transformers located in the following environments may* require further plant-specific activities, which are described in Section 6:

- Exposure to normal temperatures in excess of 40°C [104°F] for significant periods (or 30°C [86°F] average temperature for any 24-hour interval).

- Exposure to abnormal electrical loading conditions (such as loading in excess of nameplate kVA, unbalanced ac voltages, fault conditions, lightning-induced surges, etc.).

- Exposure to environments containing high levels of dust, dirt, or other airborne contaminants such as salt or chemical vapor.

* These activities may not be required for those transformers specifically designed for extraordinary ambient conditions (such as high temperature, dust, etc.).

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EXHIBIT 10

The IEEE Standard Dictionary of Electrical and Electronics Terms

Sixth Edition

Standards Coordinating Committee 10, Terms and Definitions
Jane Radatz, Chair

This standard is one of a number of information technology dictionaries being developed by standards organizations accredited by the American National Standards Institute. This dictionary was developed under the sponsorship of voluntary standards organizations, using a consensus-based process.

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Introduction

Since the first edition in 1941 of the American Standard Definitions of Electrical Terms, the work now known as IEEE Std 100, The IEEE Standard Dictionary of Electrical and Electronics Terms, has evolved into the unique compendium of terms that it is today.

The current edition includes all terms defined in approved IEEE standards through December 1996. Terms are categorized by their technical subject area. They are also associated with the standards or publications in which they currently appear. In some cases, terms from withdrawn standards are included when no current source can be found. Earlier editions of IEEE Std 100 included terms from sources other than IEEE standards, such as technical journals, books, or conference proceedings. These terms have been maintained for the sake of consistency and their sources are listed with the standards in the back of the book.

The practice of defining terms varies from standard to standard. Many working groups that write standards prefer to work with existing definitions, while others choose to write their own. Thus terms may have several similar, although not identical, definitions. Definitions have been combined wherever it has been possible to do so by making only minor editorial changes. Otherwise, they have been left as written in the original standard.

Users of IEEE Std 100 occasionally comment on the surprising omission of a particular term commonly used in an electrical or electronics field. This occurs because the terms in IEEE Std 100 represent only those defined in the existing or past body of IEEE standards. To respond to this, some working groups obtain authorization to create a glossary of terms used in their field. All existing, approved standard glossaries have been incorporated into this edition of IEEE Std 100, including the most current glossaries of terms for computers and power engineering.

IEEE working groups are encouraged to refer to IEEE Std 100 when developing new or revised standards to avoid redundancy. They are also encouraged to investigate deficiencies in standard terms and create standard glossaries to alleviate them.

The sponsoring body for this document was Standards Coordinating Committee 10 on Definitions (SCC10), which consisted of the following members:

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How to use this dictionary

The terms defined in this dictionary are listed in *letter-by-letter* alphabetical order. Spaces are ignored in this style of alphabetization, so *cable value* will come before *cab signal*. Descriptive categories associated with the term in earlier editions of IEEE Std 100 will follow the term in parentheses. New categories appear after the definitions (see Categories, below), followed by the designation of the standard or standards that include the definition. If a standard designation is followed by the letter s, it means that edition of the standard was superseded by a newer revision and the term was not included in the revision. If a designation is followed by the letter w, it means that edition of the standard was withdrawn and not replaced by a revision. A bracketed number refers to the non-IEEE standard sources given in the back of the book.

Acronyms and abbreviations are no longer listed in a separate section in the dictionary; rather, they are incorporated alphabetically with other terms. Each acronym or abbreviation refers to its expanded term, where it is defined. Acronyms and abbreviations for which no definition was included in past editions have been deleted from this edition of IEEE Std 100.

Abstracts of the current set of approved IEEE standards are provided in the back of the book. It should be noted that updated information about IEEE standards can be obtained at any time from the IEEE Standards World Wide Web site at http://standards.ieee.org/.

Categories

The category abbreviations that are used in this edition of IEEE Std 100 are defined below. This information is provided to help elucidate the context of the definition. Older terms for which no category could be found have had the category "Std100" assigned to them. Note that terms from sources other than IEEE standards, such as the National Electrical Code® (NEC®) or the National Fire Protection Association, may not be from the most recent editions; the reader is cautioned to check the latest editions of all sources for the most up-to-date terminology.

transfer trip A form of remote trip in which a communication channel is used to transmit a trip signal from the relay location to a remote location (PE/SWG) C37.100-1992

transform analysis A software development technique in which the structure of a system is derived from analyzing the flow of data through the system and the transformations that must be performed on the data. *Synonyms:* transform-centered design; transformation analysis. *See also:* data structure-centered design; input-process-output; modular decomposition; object-oriented design; rapid prototyping; stepwise refinement; structured design; transaction analysis. (C) 610.12-1990

transformation A segment attribute that determines the translation, scaling, and rotation applied to a segment when it is displayed on a display surface. (C) 610.6-1991

transformation analysis *See:* transform analysis.

transformation function A mapping function that performs graphical coordinate transformations such as scaling, rotation, and translation. (C) 610.6-1991

transform-centered design *See:* transform analysis.

transformer (1) A device, which when used, will raise or lower the voltage of alternating current of the original source. (NEC/NESC) [86]

(2) (power and distribution transformers) A static electric device consisting of a winding, or two or more coupled windings, with or without a magnetic core, for introducing mutual coupling between electric circuits. Transformers are extensively used in electric power systems to transfer power by electromagnetic induction between circuits at the same frequency, usually with changed values of voltage and current. (PE) C57.12.80-1978r

(3) (failure data for power transformers and shunt reactors) A static electric device consisting of a winding, or two or more coupled windings, with or without a magnetic core, for introducing mutual coupling between electric circuits. *Note:* The transformer includes all transformer-related components, such as bushings, LTCs, fans, temperature gauges, etc, and excludes all system-related components, such as surge arresters, grounding resistors, high voltage switches, low-voltage switches, and house service equipment. (PE) C57.117-1986r

(4) An inductive electrical device which uses electromagnetic energy to transform voltage and current levels within a circuit. (C) 610.10-1994

(5) *See also:* dry-type encapsulated water-cooled transformer; dry-type transformer; liquid-filled, or liquid-cooled transformer; transformer coupled. (IA) 668-1987w

transformer, alternating-current arc welder A transformer with isolated primary and secondary windings and suitable stabilizing, regulating, and indicating devices required for transforming alternating current from normal supply voltages to an alternating-current output suitable for arc welding. (EEC) [91]

transformer category definitions (distribution, power and regulating transformers) *Note:* All kVA ratings are minimum nameplate kVA for the principal windings. Category I includes distribution transformers manufactured in accordance with ANSI C57.12.20-1974, Requirements for Overhead-Type Distribution Transformers 67 000 Volts and Below; 500 kVA and Smaller, up through 500 kVA, single phase or three phase. In addition, autotransformers of 500 equivalent two-winding kVA or less that are manufactured as distribution transformers in accordance with ANSI C57.12.20-1974 are included in Category I, even through their nameplate kVAs may exceed 500. (PE) C57.12.00-1987s

transformer class designations *See:* transformer, oil-immersed.

transformer, constant-voltage *See:* constant-voltage transformer.

transformer correction factor (TCF) The ratio of the true watts or watthours to the measured secondary watts or watthours, divided by the marked ratio. *Note:* The transformer correction factor for a current or voltage transformer is the ratio correction factor multiplied by the phase angle correction factor for a specified primary circuit power factor. The true primary watts or watthours are equal to the watts or watthours measured, multiplied by the transformer correction factor and the marked ratio. The true primary watts or watthours, when measured using both current and voltage transformers, are equal to the current transformer ratio correction factor multiplied by the voltage transformer ratio correction factor multiplied by the marked ratios of the current and voltage transformers multiplied by the observed watts or watthours. It is usually sufficiently accurate to calculate true watts or watthours as equal to the product of the two transformer correction factors multiplied by the marked ratios multiplied by the observed watts or watthours. (PE) [57], C57.12.80-1978r, C57.13-1993

transformer coupled (electrical heating applications to melting furnaces and forehearths in the glass industry) The power modulation device is connected in the primary circuit of a transformer whose secondary circuit is connected to the glass. (IA) 668-1987w

transformer, dry-type *See:* dry-type transformer.

transformer, energy-limiting A transformer that is intended for use on an approximately constant-voltage supply circuit and that has sufficient inherent impedance to limit the output current to a thermally safe maximum value. *See also:* transformer, specialty. (PE) [57]

transformer equipment rating A volt-ampere output together with any other characteristics, such as voltage, current, frequency, and power factor, assigned to it by the manufacturer. *Note:* It is regarded as a test rating that defines an output that can be taken from the item of transformer equipment without exceeding established temperature-rise limitations, under prescribed conditions of test and within the limitations of established standards. *See also:* duty. (PE) [57]

transformer, grounding *See:* grounding transformer.

transformer grounding switch and gap (capacitance potential devices) Consists of a protective gap connected across the capacitance potential device and transformer unit to limit the voltage impressed on the transformer and the auxiliary or shunt capacitor, when used; and a switch that when closed removes voltage from the potential device to permit adjustment of the potential device without interrupting high-voltage line operation and carrier-current operation when used. *See also:* outdoor coupling capacitor. (PE) 43-1974r

transformer, group-series loop insulating An insulating transformer whose secondary is arranged to operate a group of series lamps and/or a series group of individual-lamp transformers. *See also:* transformer, specialty. (PE) [57]

transformer, high-power-factor A high-reactance transformer that has a power-factor-correcting device such as a capacitor, so that the input current is at a power factor of not less than 90% when the transformer delivers rated current to its intended load device. *See also:* transformer, specialty. (PE) [116]

transformer, high-reactance (1) (output limiting) An energy-limiting transformer that has sufficient inherent reactance to limit the output current to a maximum value. *See also:* transformer, specialty. (PE) [57]

(2) (secondary short-circuit current rating) The current in the secondary winding when the primary winding is connected to a circuit of rated primary voltage and frequency and when the secondary terminals are short-circuited. *See also:* transformer, specialty. (PE) [57]

(3) (kilovolt-ampere or voltampere short-circuit input rating) The input kilovolt-amperes or volt-amperes at rated primary voltage with the secondary terminals short-circuited. *See also:* transformer, specialty. (PE) [57]

transformer, ideal A hypothetical transformer that neither stores nor dissipates energy. *Note:* An ideal transformer has the following properties: Its self and mutual impedances are

UNITED STATES
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In re: Docket Nos. 50-247-LR and License Renewal Application Submitted by Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc.	50-286-LR ASLBP No. 07-858-03-LR-BD01 DPR-26, DPR-64 September 23, 2009

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CERTIFICATE OF SERVICE

I certify that on September 23, 2009, I served copies of the State of New York's response to Entergy's motion for summary disposition and NRC Staff's response on the following judges, law clerks, offices, organizations, attorneys, parties, and/or petitioners via e-mail and first-class U.S. Mail at the e-mail and street addresses that follow:

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