UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 61 TO FACILITY OPERATING LICENSE NO. DPR-18

ROCHESTER GAS AND ELECTRIC CORPORATION

R. E. GINNA NUCLEAR POWER PLANT

DOCKET NO. 50-244

1.0 INTRODUCTION

Rochester Gas and Electric Corporation (RG&E or the licensee) proposed to amend Appendix A of the license to revise the R. E. Ginna Nuclear Power Plant (Ginna) Technical Specifications (TSs) in their entirety. The amendment consists of:

(1) a full conversion from the current TSs to a set of TSs based on NUREG-1431, "Standard Technical Specifications, Westinghouse Plants," Revision 0, dated September 1992 (including approved travellers used in the issuance of Revision 1, dated April 1995). This part is in response to the licensee's application dated May 26, 1995, as supplemented by letters dated July 17, August 14, August 31, September 18, October 6, October 18, November 1, November 16, two letters of November 20, November 21, November 22, two letters of November 27, November 30, December 8, and December 28, 1995.

(2) a revision to the TSs to implement the amended regulation 10 CFR Part 50, Appendix J, Option B (new rule), to provide a performance based option for leakage-rate testing of containment, in response to the licensee's application dated November 27, 1995.

(3) a revision to the TSs regarding allowable primary coolant levels of specific activity, in response to the licensee's application dated May 23, 1994, as supplemented by letters dated June 15, 1994, July 11, July 15, November 1, and November 16, 1995.

(4) a revision to the TSs with adding requirements that enhance the reliability of power-operated relief valves and block valves (PORV/BV) along with TS changes that provide additional low-temperature overpressure protection, in response to the licensee's application dated September 15, 1992, as supplemented April 20, 1993, and April 26, 1995. By letter dated July 27, 1995, the licensee withdrew this amendment request; however, the licensee rescinded this withdrawal request by letter dated December 28, 1995. Therefore, the proposed changes to the PORV/BV, as requested in the licensee's letter dated May 26, 1995, as supplemented December 28, 1995, are incorporated into this amendment request.

9602230013 960213
PDR ADOCK 05000244
P PDR

The licensee based the proposed amendment request (Item 1, above) on NUREG-1431, "Standard Technical Specifications (STS) Westinghouse Plants," issued in September 1992. The licensee also based the amendment request on guidance provided in the U.S. Nuclear Regulatory Commission's (NRC's) "Final Policy Statement on Technical Specifications Improvements for Nuclear Power Reactors," Final Policy Statement published in the Federal Register on July 22, 1993 (58 FR 39132). In addition, the licensee used portions of the existing TSs as a basis for the Ginna improved TSs. Consistent with the NRC's Final Policy Statement, the overall objective of the proposed amendment was to completely rewrite, reformat, and streamline the existing Ginna TSs. The licensee also proposed transferring some TSs requirements to other licensee-controlled documents. The amendment emphasized human factors principles to clarify the Ginna improved TSs, and to define more clearly the appropriate scope of the TSs. In addition, the licensee proposed significant changes to the Bases section of the Ginna TSs to enhance the clarity and understanding of each specification. During a week-long series of public meetings concluding on November 21, 1995, the NRC staff discussed with the licensee plant-specific issues, including plant-unique design features, requirements, and operating practices. In addition, the NRC staff held meetings with the Owners' Groups to discuss matters of a generic nature that were not incorporated in NUREG-1431; these generic issues were considered for specific applications in the Ginna improved TSs.

In addition, the licensee has submitted a number of changes to the existing Ginna TSs (Items 2, 3, and 4, above). The NRC staff's review and approval of these TS changes was independent of the Ginna improved TSs review effort. These TSs changes are reflected, as appropriate, in the Ginna improved TSs. This Safety Evaluation (SE) describes those TS changes that affected rule implementing the Ginna improved TSs.

During its review of the Ginna license amendment application, the NRC staff relied on the Commission's Final Policy Statement and NUREG-1431. This SE documents the basis for the NRC staff's conclusion that Ginna can base its improved TSs on NUREG-1431, as modified by plant-specific changes, and that the use of the Ginna improved TSs is acceptable for continued plant operation. The NRC staff also acknowledges that, in accordance with the Commission's Final Policy Statement, the conversion to the STS is a voluntary process. Therefore, the Ginna improved TS reflect some differences that correspond to the existing licensing basis for the plant. In this SE, the NRC staff has identified the changes to the existing Ginna TS, and has included an explanation of the significant differences. Individual section topics and the corresponding section numbers are consistent with those used in NUREG-1431, but renumbered to accommodate changes in required limiting conditions for operation (LCOs) based on the Ginna design.

The Commission's proposed action on the Ginna license amendment request was published in the Federal Register on September 26, 1995 (60 FR 49636). This SE addresses changes to the licensee's proposed TS resulting from discussions with the licensee during the NRC staff's review. These plant-specific changes serve to clarify the TS with respect to the guidance in the Commission's Final

Policy Statement and NUREG-1431. Therefore, the changes are within the scope of the action described in the initial Federal Register notice.

2.0 BACKGROUND

Section 182a of the Atomic Energy Act of 1954, as amended (the Act), requires that applicants for nuclear power plant operating licenses shall submit detailed TS, as follows:

> [S]uch technical specifications, including information of the amount, kind, and source of special nuclear material required, the place of the use, the specific characteristics of the facility, and such other information as the Commission may, by rule or regulation, deem necessary in order to enable it to find that the utilization . . . of special nuclear material will be in accord with the common defense and security and will provide adequate protection to the health and safety of the public. Such technical specifications shall be a part of any license issued.

In 10 CFR 50.36, the Commission established its regulatory requirements related to the content of TS. In so doing, the Commission emphasized matters related to preventing accidents, and as well as matters related to mitigating accident consequences. The Commission noted that applicants are expected to incorporate into their TS "those items that are directly related to maintaining the integrity of the physical barriers designed to contain radioactivity" (See Statement of Consideration, "Technical Specifications for Facility Licenses; Safety Analysis Reports," December 17, 1968, 33 FR 18610). Pursuant to 10 CFR 50.36, TS are required to include items in five specific categories, including (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation (LCOs); (3) surveillance requirements (SRs); (4) design features; and (5) administrative controls. However, the rule does not specify the particular requirements to be included in a plant's TS.

For several years, the NRC and industry representatives have sought to develop guidelines for improving the content and quality of nuclear power plant TS. On February 6, 1987, the Commission issued an interim policy statement on TS improvements, entitled "Proposed Policy Statement on Technical Specification Improvements for Nuclear Power Reactors" (52 FR 3288). From 1989 through 1992, the various utility Owners' Groups and the NRC staff developed improved STS that established models of the Commission's policy for each primary reactor type. In addition, the NRC staff, licensees, and Owners' Groups developed generic administrative and editorial guidelines in the form of a "Writer's Guide" for technical specifications. This Writer's Guide significantly enhances human factors considerations, and was used throughout the development of licensee-specific improved TS.

In September 1992, the Commission issued NUREG-1431, which was developed using the guidance and criteria contained in the Commission's interim policy statement. NUREG-1431 was established as a model for developing improved TS for Westinghouse plants in general. NUREG-1431 reflects the results of a detailed review of the application of the interim policy statement criteria to generic system functions, which were published in a "Split Report" issued to the Nuclear Steam System Supplier (NSSS) Owners Groups in May 1988. NUREG-1431 also reflects the results of extensive discussions concerning various drafts of STS, so that the application of the TS criteria and the Writer's Guide would consistently reflect detailed system configurations and operating characteristics for all NSSS designs. As such, the generic Bases presented in NUREG-1431 provide an abundance of information regarding the extent to which the STS present requirements that are necessary to protect the public health and safety.

On July 22, 1993, the Commission issued its Final Policy Statement, expressing the view that satisfying the guidance in the policy statement also satisfies Section 182a of the Act and 10 CFR 50.36. The Final Policy Statement described the safety benefits of the improved STS, and encouraged licensees to use the improved STS as the basis for plant-specific TS amendments, and for complete conversions to improved STS. Further, the Final Policy Statement provided guidance for evaluating the required scope of the TS, and finalized the criteria to be used in determining which design conditions and associated surveillances need to be incorporated in the TS. The Final Policy Statement explicitly allowed certain items to be relocated to licensee-controlled documents, while requiring that other items be retained in the TS. In so doing, as the Commission noted in 58 FR 39136, it was adopting the qualitative standard enunciated by the Atomic Safety and Licensing Appeal Board (ASLAB) in the case of *Portland General Electric Company* (Trojan Nuclear Plant), ALAB-531, 9 NRC 263, 273 (1979). In that case, the ASLAB made the following observation:

> [T]here is neither a statutory nor a regulatory requirement that every operational detail set forth in an applicant's safety analysis report (or equivalent) be subject to a technical specification, to be included in the license as an absolute condition of operation which is legally binding upon the licensee unless and until changed with specific Commission approval. Rather, as best we can discern it, the contemplation of both the Act and the regulations is that technical specifications are to be reserved for those matters as to which the imposition of rigid conditions or limitations upon reactor operation is deemed necessary to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety.

In accordance with this approach, existing TS requirements that fall within or satisfy any of the criteria in the Final Policy Statement should be retained in the TS. By contrast, TS requirements that do not fall within or satisfy these criteria may be relocated to other licensee-controlled documents. The Final Policy Statement criteria are as follows:

(1) installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary

(2) a process variable, design feature, or operating restriction that is an initial condition of a design-basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier

(3) a structure, system, or component that is part of the primary success path, and that functions or actuates to mitigate a design-basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier

(4) a structure, system, or component shown by operating experience or probabilistic safety assessment to be significant to public health and safety[1]

In its license amendment application, the licensee proposed changes to existing TS requirements using the Final Policy Statement and NUREG-1431 as guidance. The licensee also proposed changes to NUREG-1431 because of differences between the plant-specific licensing basis and the design basis provided under Bases in NUREG-1431.

In this SE, the licensee's proposed changes to existing TS requirements are grouped into four general categories, including administrative (i.e., non-technical) changes; relocated requirements (i.e., requirements moved from existing NRC-controlled TS to specified licensee-controlled documents); more restrictive requirements (i.e., additions to existing TS); and less restrictive requirements (i.e., relaxations to, or deletions from, existing TS requirements). These four general categories of changes to the licensee's existing TS requirements may be better understood as described in the following paragraphs.

2.1 Administrative Changes

Non-technical, administrative changes were intended to incorporate human-factors principles into the form and structure of the improved plant TS, so that they would be easier to use for plant operations personnel. These changes are editorial in nature, or involve reorganizing or reformatting requirements without affecting technical content or operational requirements. Every section of the proposed TS reflects this type of change.

---

[1] The Commission recently adopted amendments to 10 CFR 50.36, pursuant to which the rule was revised to codify and incorporate these criteria (See Final Rule, "Technical Specifications," 60 FR 36953, July 19, 1995). The Commission indicated that reactor core isolation cooling, isolation condenser, residual heat removal, standby liquid control, and recirculation pump trip are to be included in the TS under Criterion 4, although it recognized that other structures, systems, and components could also meet this criterion.

In order to ensure consistency, the NRC staff and the various licensees of the Westinghouse conversion plants have used NUREG-1431 as guidance to reformat and make other administrative changes. The licensees proposed such changes as providing the appropriate numbers for NUREG-1431-bracketed information (information that must be supplied on a plant-specific basis), (b) identifying plant-specific wording for system names, etc., and (c) changing NUREG-1431 section wording to conform to existing licensee practices. The single most significant change resulting from items relocated within improved TS is that the improved TS will be easier to use because all TS requirements have been placed in the section arrangement standardized throughout the industry. The appendix to this SE contains a table illustrating how the individual existing TS sections were relocated within the format of NUREG-1431.

The NRC staff reviewed all of the administrative and editorial changes proposed by the licensee (or generically by the Westinghouse licensees), and finds them acceptable because they are compatible with the "Writer's Guide" and NUREG-1431, and they are consistent with the Commission's regulations. The non-technical administrative changes are discussed individually in this SE.

2.2 Relocated Requirements

As summarized above, the Commission's Policy Statement and revised rule in 10 CFR 50.36 allow existing TS requirements which do not satisfy or fall within any of the four specified criteria to be relocated to appropriate licensee-controlled documents. In the licensee's application, such requirements are generally relocated to the Updated Final Safety Analysis Report (UFSAR) and TS Bases.

Unless otherwise specified in this safety evaluation, the relocated LCO portion of the existing TS (which includes the system description, design limits, functional capabilities, and performance levels), will be relocated to the UFSAR. The relocated provisions of the existing TS action statements and surveillance requirements will be relocated to the UFSAR or TS Bases, depending on the nature of the requirements in question.

In addition, the details and methods concerning operation of a system during the performance of a surveillance have been relocated from the existing TS. Examples include descriptions of tests to ensure that controls during functional testing of component controls are operable. These procedures will similarly be described in the UFSAR or TS Bases. Tables 1 to 9 summarize the requirements being relocated from the existing plant TS to licensee-controlled documents.

The facility and procedures described in the UFSAR and TS Bases can only be revised in accordance with the provisions of 10 CFR 50.59. These provisions ensure an auditable and appropriate control over the relocated requirements and any future changes to these requirements. Other licensee-controlled documents include provisions for making changes consistent with other applicable regulatory requirements. For example, the Offsite Dose Calculation Manual (ODCM) can be changed in accordance with 10 CFR Part 20; the Emergency

Plan Implementing Procedures (EPIP) can be changed in accordance with 10 CFR 50.54(q); and the administrative instructions that implement the Quality Assurance Manual (QAM) can be changed in accordance with 10 CFR 50.54(a) and 10 CFR Part 50, Appendix B. In addition, temporary procedure changes are controlled by 10 CFR 50.54(a).

The UFSAR already includes most of the design information described above. Nevertheless, by letter dated December 28, 1995, the licensee committed to confirm that these details are appropriately reflected in the UFSAR or improved TS Bases, or will be included in the next update of these documents. The licensee also committed to maintain an auditable record of, and an implementation schedule for, the procedure changes associated with developing the improved plant-specific TS. The licensee will maintain the documentation of these changes in accordance with the record retention requirements specified in the Quality Assurance Plan.

As described in detail in this SE, the NRC staff concludes that the licensee has identified appropriate controls for all of the requirements that are being relocated from the TS to licensee-controlled documents. Until incorporated in the UFSAR and procedures, changes to the provisions being relocated from the TS will be controlled in accordance with the applicable existing procedures that control these documents. The NRC will conduct an audit of the relocated requirements following implementation to ensure that an appropriate level of control has been achieved. The NRC staff also concludes that sufficient regulatory controls exist under the regulations (particularly 10 CFR 50.59 and 10 CFR 50.54(a) and (q)) for the relocated items. The NRC staff concludes that the control of these provisions under 10 CFR 50.59 or other applicable regulation is acceptable, that the regulatory requirements provide sufficient control of these provisions, and that removing them from the TS is acceptable. Accordingly, the NRC staff concludes that these requirements, as described in detail in this SE, may be relocated from the TS to the UFSAR or to other licensee-controlled documents as specified herein.

2.3 More Restrictive Requirements

The licensee's proposed improved TS include certain requirements that are more restrictive than those contained in the existing TS. These requirements either are more conservative than corresponding requirements in the existing TS, or are additional restrictions contained in NUREG-1434 but not contained in the existing TS. Examples of more restrictive requirements include imposing an LCO on plant equipment that is not required by the present TS to be operable, more restrictive requirements to restore inoperable equipment, and more restrictive surveillance requirements. The more restrictive requirements are discussed individually in Section 3.0 of this SE. These more restrictive requirements have been found to be acceptable for the reasons stated in this SE.

2.4 Less Restrictive Requirements

The less restrictive requirements are justified on a case-by-case basis, as discussed in Section 3.0 of this SE. When requirements have been shown to provide little or no safety benefit, their removal from the TS may be appropriate. In most cases, relaxations previously granted on a plant-specific basis resulted from generic NRC actions, new NRC staff positions that evolved from technological advancements and operating experience, or resolution of the Owners Groups' comments on the improved STS. Generic relaxations contained in NUREG-1431, such as eliminating cross references to existing regulatory requirements, are redundant and generally not incorporated into NUREG-1431.

The NRC staff reviewed the proposed less restrictive requirements, and found them to be acceptable because they are consistent with current licensing practices and NRC regulations. The NRC staff also reviewed the licensee's design to determine if the specific design Bases and licensing bases are consistent with the technical bases for the model requirements in NUREG-1431, and thus provide a basis for the revised TS.

In general, the NRC staff concluded that the conversion of the licensee's existing TS to improved TS based on NUREG-1431, as modified by plant-specific changes, is acceptable because it is consistent with the current plant-specific licensing basis, applicable regulatory requirements, and guidance of the Commission's Final Policy Statement. The following sections explain the NRC staff's basis for this conclusion.

3.0 EVALUATION OF APPLICATION FOR CONVERSION TO IMPROVED TECHNICAL SPECIFICATIONS

3.1 Use and Application

3.1.1 Definitions

The definitions appearing in Section 1 of the Ginna improved TS have been reorganized from the existing Ginna TS. Specifically, the licensee deleted the identification numbers associated with each definition, and listed them in alphabetical order. In addition, the licensee made some editorial changes, so that the defined terms are consistent with NUREG-1431 and with Ginna plant-specific terminology. The NRC staff has accepted the modifications, and the resulting definitions do not change the intent found in NUREG-1431. Therefore, the NRC staff finds these definitions acceptable for Ginna. The following definitions have been retained in the Ginna improved TS:

a. Channel Calibration
b. Channel Check
c. Channel Functional Test
d. Dose Equivalent I-131
e. Operable-Operability
f. Quadrant Power Tilt Ratio
g. Reactor Operating Modes
h. Refueling
i. Shutdown Margin (SDM)
j. Thermal Power

The following new definitions have been added to the Ginna improved TS:

k. Actions
l. Actuation Logic Test
m. Axial Flux Difference (AFD)
n. Channel Operational Test (COT)
o. Core Alteration
p. Core Operating Limits Report (COLR)
q. E bar - Average Disintegration Energy
r. Leakage
s. Mode
t. Physics Tests
u. Pressure Temperature Limits Report (PTLR)
v. Quadrant Power Tilt Ratio (QPTR)
w. Rated Thermal Power (RTP)
x. Staggered Test Basis
y. Trip Actuating Device Operational Test (TADOT)

These new definitions are compatible with changes made throughout the Ginna improved TS to clarify the related requirements and to reduce the likelihood of misinterpretation of the improved TS. With the exception of L_a (Maximum Allowable Leakage Rate, see 10 CFR Part 50, Appendix J), the new Ginna definitions were also defined in NUREG-1431. Plant-specific wording differences have been reviewed, and do not change the meaning of these definitions.

In electing to implement the specifications of NUREG-1431, Section 1.0, the licensee proposed a number of conditions that are less restrictive than those allowed by the existing TS. The more significant of these are as follows:

1. The phrase "or actual," in reference to the injected signal, has been added to the definition of Channel Functional Test. Some channel functional tests are performed by inserting the source signal into the logic (e.g., RTS permissives). For others, there is no reason why an actual signal would preclude satisfactory performance of the test. Use of an actual signal, instead of a simulated signal or source signal as specified by the existing requirement, will not affect the performance of the channel. Operability can be adequately demonstrated in either case, since the channel itself can not discriminate between "actual" or "simulated."

2. The existing TS define OPERABLE-OPERABILITY to include supports as components that are implicit in assumptions that the system, subsystem, train, component, or device is capable of performing its intended function. Supports are design features for environmental and dynamic effects associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. Therefore, supports are not attendant system features without which system operability can not be established. Rather, the failure of a system support represents a degraded or non-

conforming design condition (depending on the extent of the failure). Operability can adequately be established with the STS definition of OPERABLE-OPERABILITY, without a comprehensive list of necessary attendant features.

The NRC staff reviewed the above less restrictive requirements, and found them to be acceptable because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with current licensing practices, operating experience, and plant accident and transient analyses, and provide reasonable assurance that the public health and safety will be protected.

In electing to implement the specifications of NUREG-1431, Section 1.0, the licensee proposed not to adopt a number of NUREG-1431 definitions related to instrumentation surveillance requirements that are more restrictive than the existing Bases for the current license. These include definitions for engineered safety feature response time testing, reactor trip system response time testing, master relay tests, and slave relay tests. The NRC staff reviewed each of the proposed deviations from the NUREG requirements, and found them to be acceptable because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with current licensing practices, operating experience, and plant accident and transient analysis, and provide reasonable assurance that the public health and safety will be protected.

All other definitions in the existing Ginna TS (1.5, 1.6, 1.7.4, 1.8, 1.10, 1.16, 1.17, and 1.19) are no longer used as defined terms in the Ginna improved TS. Definition 1.12 has been reformatted, and its concepts appear in Section 1.4 of the Ginna improved TS. Definition 1.20 has been reformatted, and the concepts are contained in Section 4.3 of the Ginna improved TS. In addition, definitions 1.13, 1.14 and 1.15 have been reformatted, and these concepts are contained in Section 5.0 of the Ginna improved TS. The remaining definitions are inapplicable under the improved TS, and therefore may be deleted from the Ginna improved TS.

As noted above, the NRC staff and the licensee agreed to minor word changes throughout the Ginna improved TS definition section. These word changes involve clarifications that do not alter the meanings of the definitions or change the restrictive level of the TS.

The definitions in Section 1.0 perform a supporting function for other sections in the Ginna improved TS. The NRC staff reviewed the proposed changes in the definition section for their effect on the safety limits (SLs) and SL violations that appear in Section 2.0, and the LCOs and action statements in Section 3, including the surveillance requirements (SRs). The NRC staff finds no adverse effects that would result from the proposed changes. Consequently, the NRC staff concludes that when the definitions, as modified, are applied in other sections of the TS, the restrictive level of the requirements are not changed and, therefore, the safety margins are not affected. In addition, the NRC staff concludes that the licensee's proposed changes clarify the definitions and reduce the tendency for misinterpretation.

Further, the NRC staff finds that Ginna improved TS definitions appropriately apply the guidance provided in NUREG-1431. Therefore, the NRC staff finds the changes acceptable.

3.1.2 Logical Connectors

This new Section 1.2 in the Ginna improved TS uses examples to explain the meaning and use of "logical connectors" so that the entire Ginna improved TS are clearer from a human factors standpoint. The NRC staff reviewed this section, and considers this proposed addition and reformatting to be an enhancement to the Ginna improved TS. Further, the NRC staff finds that the addition is consistent with NUREG-1431, and is acceptable.

3.1.3 Completion Times

This new Section 1.3 in the Ginna improved TS does not change "completion times," but provides guidance (through examples) on the use of completion times. Completion time is the amount of time allowed to complete an action, or the amount of time allowed for a structure, system, or component to be inoperable. This section is administrative in nature, and is provided as an aid to the licensee's staff. The NRC staff reviewed this section, and finds that it is consistent with NUREG-1431, and is acceptable.

3.1.4 Frequency

This new Section 1.4 in the Ginna improved TS defines the proper use and application of surveillance frequency practices through the use of examples. A clear understanding of the correct application of a specified frequency is necessary to ensure compliance with a surveillance requirement.

The NRC staff reviewed this section and finds that the "Frequency Notation" definition 1.12 of the existing TS have adequately been incorporated into the descriptions and examples of this section. Further, the NRC staff finds that this section is consistent with NUREG-1431 and is acceptable.

3.2 Safety Limits

3.2.1 Significant Administrative Changes

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed administrative changes to bring the existing TS into conformance with NUREG-1431. Among these changes, the licensee reformatted and reorganized the Safety Limits section to separate the safety limits and safety limit violations.

The NRC staff reviewed the licensee's proposed Section 2.0, based on NUREG-1431, as modified to include plant-specific limits and terminology, and finds that this section is consistent with the Commission's regulations, and is acceptable. The above changes result in the same limits as the current requirements, or represent enhanced presentation of the existing TS intent.

Accordingly, the improved TS changes are purely administrative and are acceptable.

3.2.2 Relocated Requirements

Existing TS	Title
2.3	Limiting Safety System Settings Protective Instrumentation
6.7	Safety Limit Violation

In accordance with the guidance in NUREG-1431, the licensee proposed administrative changes to existing TS to bring them into conformance with the improved TS. Existing TS 2.3, "Limiting Safety System Settings, Protective Instrumentation," is relocated to TS 3.3.1.1, "Reactor Protection System Instrumentation," to bring it into conformance with NUREG-1431. Existing TS 2.3 specifies the reactor protection system (RPS) instrumentation trip settings. The improved TS address these items within TS 3.3.1.1.

The protection and monitoring functions of the RPS have been designed to ensure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of equipment performance and parameters directly monitored by the RPS, as well as LCOs on other reactor system parameters. The LSSS are defined in this specification as the trip setpoints. In conjunction with the LCOs, these trip setpoints establish the threshold for protective system action to prevent exceeding acceptable limits, including SLs, during design-basis accidents (DBAs).

The trip setpoints are the limiting values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the allowable tolerance band for channel calibration accuracy. Thus, the RPS setpoints are effectively retained within the improved TS. The LCO and applicability of each RTS function are provided in Table 3.3.1-1, which also includes trip setpoints for all applicable RTS functions. Trip setpoints for RTS functions not specifically modeled in the safety analysis are based on established limits provided in plant procedures. RTS functions ensure that SLs are not violated during Anticipated Operational Occurrences (AOOs), and that the consequences of DBAs will be acceptable. Analytical values for these RTS functions ensure that the plant is operated within the LCOs (including any required actions that are in effect at the onset of the AOO or DBA), and that the equipment functions as designed. These analytical values are provided in plant procedures.

The above changes result in the same limits as the current requirements. Accordingly, the improved TS changes are purely administrative and they are acceptable.

In accordance with the guidance of NUREG-1431, the licensee proposed to relocate all or portions of the following existing TS to licensee-controlled documents.

1. Existing TS 2.3.3.1, TS 2.3.3.2, and TS Figure 2.3-1 establish measurement error allowances for the loss of voltage and degraded voltage functions. The tolerance values are less than 5% of the measured values. These values may be compared directly to the curves in Figure 2.3-1. The existing TS require that appropriate actions be taken if the measurement error for the loss of voltage and degraded voltage trip setpoints is exceeded. The LSSS for the loss of voltage and degraded voltage functions were revised in the improved TS to provide a minimum trip setpoint value. Criteria for establishing equivalent values based on measured voltage versus relay operating time were relocated to the Bases for LCO 3.3.4.

2. The Safety Limits section for SL violation reports prepared for offsite, onsite, and Commission review functions are relocated to the Technical Requirements Manual (TRM). The NRC staff reviewed the licensee's proposed Section 2.0, based on NUREG-1431, and finds that this section is consistent with the Commission's regulations in 10 CFR 50.36(c)(1)(i)(A), and is acceptable.

3. Existing TS 6.7.1.b and 6.7.1.c specify safety limit violation report contents, review responsibilities, and the time for providing this report to utility management. The licensee proposed that these requirements not be retained in the TS. The general requirements for the report's contents are dictated by 10 CFR 50.73 for LERs. These requirements are included in licensee procedures, which implement 10 CFR 50.72 and 10 CFR 50.73. The requirement to provide the report to onsite safety review group and utility management (specified in existing TS 6.7.1.d) are to be relocated to the TRM, and changes to the TRM will be controlled by 10 CFR 50.59. The NRC staff concludes that the control of these provisions under 10 CFR 50.59 is acceptable, that the regulatory requirements provide sufficient control of these provisions, and that removing them from the TS is acceptable.

The above relocated requirements related to trip setpoint measurement error, safety limits and safety limit violations are not required to be in the TS under 10 CFR 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. Further, they do not fall within any of the four criteria set forth in the Commission's Final Policy Statement, discussed in the Introduction above. The NRC staff concludes that the control of these provisions under 10 CFR 50.59 is acceptable, that the regulatory requirements provide sufficient control of these provisions, and that removing them from the TS is acceptable. Accordingly, the NRC staff concludes that these requirements may be relocated from the TS to the UFSAR, TS Bases, or TRM, as applicable.

3.2.3 More Restrictive Requirements

By electing to implement NUREG-1431, Section 2.0, "Safety Limits," the licensee proposed the following more restrictive requirements than are

required by the existing TS. The more restrictive requirements particularly relate to the following areas:

1. The applicability of existing TS 2.1 is extended to all modes of operation including Mode 2 and subcritical. Although it is physically difficult to violate some reactor core SLs in startup conditions, there is a potential for an inadvertent criticality with the reactor near normal operating temperature and pressure conditions. Any SL violation will receive the same attention and response.

2. The initial operator actions for SL violations presented in existing TS 6.7.1.a were revised to include an action for violation of the reactor coolant system (RCS) pressure SL in Modes 3, 4, and 5. Through this action, the operator must restore compliance with the SL within 5 minutes. Specifying a time limit for operators to restore compliance provides more stringent guidance to plant staff.

The NRC staff reviewed the above more restrictive generic requirements, and concludes that they enhance the improved TS. Therefore, the more restrictive requirements are acceptable.

3.2.4 Less Restrictive Requirements

In electing to implement the specifications of NUREG-1431, Section 2.0, the licensee proposed a less restrictive applicability than is allowed by the existing TS 2.2. Specifically, the applicability was revised to "Modes 1, 2, 3, 4, and 5." The proposed applicability does not require that this SL be met when fuel is in the vessel with one or more reactor vessel head closure bolts less than fully tensioned, or with the head removed. With the reactor head bolts less than fully tensioned, it is highly unlikely that the RCS can be pressurized greater than the SL pressure because of the low-temperature over-pressure protection requirements. With the head removed, it is not possible to pressurize the RCS greater than the SL pressure.

The NRC staff finds the less restrictive requirement acceptable because it does not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with current licensing practices, operating experience, and plant accident and transient analyses, and provide reasonable assurance that the public health and safety will be protected.

3.3 Limiting Conditions for Operation

This section has been renamed from the existing TS Section 3.0, "Limiting Conditions for Operation Applicability," and Section 4.0, "Surveillance Requirements." The corresponding sections in the Ginna improved TS are Section 3.0, "Limiting Condition for Operation (LCO) Applicability, SR Applicability." The licensee proposed the following changes throughout Section 3.0:

1. Existing TS 3.0.1 was revised to clarify the actions that must be implemented when an LCO is not met and an associated required action and completion time are not met and no other condition applies, or when the condition of the plant is not specifically addressed by the associated LCO actions. The improved TS replace the existing requirement that the LCO time limits apply if they are more limiting that those required by existing LCO 3.0.3. In addition, the improved TS Bases include an expanded discussion to clarify the applicability of this requirement and provide examples based on the improved TS format.

2. Existing TS 3.0.2 was replaced by improved TS LCO 3.0.6, which provides guidance regarding the appropriate actions to be taken when a single system's inoperability (e.g., a support system) also results in the inoperability of one or more related systems (e.g., supported system(s)). LCO 3.0.6 and the associated Bases clarify existing requirements consistent with plant interpretations. Consequently, this new LCO does not provide new requirements. Existing TS 3.0.2 requirements related to emergency and preferred power sources are addressed in improved TS 3.8.1.

3. Existing TS 3.0.1 was revised to remove the 1-hour time period that is allowed to prepare for a plant shutdown. The revised time requires instead that the plant be in hot shutdown (i.e., Mode 3) within 6 hours of entry of this LCO and be in cold shutdown (i.e., Mode 5) within 36 hours. Time constraints are no longer placed on initiating the plant shutdown, rather, they only apply to the time limit in which the shutdown must be completed. Since the plant must now be in a lower mode in fewer hours, this results in an additional constraint to plant operations.

These changes are considered administrative (affecting only the location of the requirements within TS), and are therefore considered acceptable.

The licensee also proposed to add five new LCOs from NUREG-1431 (LCOs 3.0.1, 3.0.2, 3.0.4, 3.0.5, and 3.0.7) and three new SRs from NUREG-1431 (SR 3.0.1, 3.0.3 and 3.0.4) to the Ginna improved TS, as follows:

1. LCO 3.0.1 establishes the applicability statement within each individual specification with regard to when the LCO is required. This LCO provides clarifying and descriptive information for LCO applicability, consistent with the NRC staff guidance provided by Generic Letter (GL) 87-09 regarding the intent and interpretation of existing specifications.

2. LCO 3.0.2 establishes that, upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met in the improved TS. This LCO provides clarifying and descriptive information for LCO applicability, consistent with the NRC staff guidance provided by GL 87-09 regarding the intent and interpretation of existing specifications.

3. LCO 3.0.4 establishes limitations on changes in Modes or other specified conditions in the applicability when an LCO is not met.

4. LCO 3.0.5 permits equipment removed from service to be returned under administrative control to perform testing to determine operability.

5. LCO 3.0.7 permits performance of special tests and operations.

6. SR 3.0.1 establishes that SRs must be met during the Modes or other specified conditions (in the applicability) for which the requirements of the LCO apply.

7. SR 3.0.3 quantifies and clarifies the maximum time delay or allowance that is permitted to perform a given surveillance.

8. SR 3.0.4 clarifies limitations on mode applicability changes during shutdown conditions and power reductions.

The NRC staff reviewed these proposed additions, and concludes that they will enhance the quality of the Ginna improved TS, and will benefit the operators and others in their understanding of the overall improved TS. The NRC staff also concludes that the Ginna improved TS appropriately apply the guidance provided in NUREG-1431, and finds that the changes are acceptable.

3.3.1 Reactivity Control Systems

3.3.1.1 Significant Administrative Changes

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed administrative changes to bring the existing TS into conformance with NUREG-1431 improved TS. The more significant changes resulting from the administrative items are as follows:

1. Existing TS 3.10.4.2 and TS 3.10.4.3, Control Rod Group Height, specify actions for immovable full length shutdown rods and control rods. Existing TS 3.10.4.2 requires a control rod to be declared inoperable due to "being immovable as a result of excessive friction or mechanical interference or known to be untrippable." Existing TS 3.10.4.3 provides requirements for a control rod "inoperable for causes other than addressed by 3.10.4.2, above, or misaligned from its group step counter demand position by more than ± 12 steps." The licensee has always interpreted existing TS 3.10.4.2 to address problems in which the control rod was unable to insert into the core within accident assumed time limits (i.e., that the rod was "untrippable"). Meanwhile, existing TS 3.10.4.3 addresses problems such as a control rod which is unable to fully withdraw. In this case, existing TS require aligning all rods in the affected control rod group or reducing power to equal to or less than 75% RTP within 1 hour. The licensee has proposed to remove "being immovable as a result of excessive friction or

mechanical interference" from existing TS 3.10.4.2 and "inoperable for causes other than addressed by 3.10.4.2, above" from existing TS 3.10.4.3. The Bases for improved TS LCO 3.1.4 state that "if a control rod(s) is discovered to be immovable but remains trippable and aligned, the control rod is considered operable." This Bases discussion is consistent with the licensee's interpretation of these existing TS requirements such that the deleted existing TS text is only considered an administrative change since the same requirements are being implemented.

2. Existing TS 3.10.4.3.2, Control Rod Group Height, specifies actions to restore a misaligned rod to within the alignment limits in 1 hour or to declare the rod inoperable. Improved TS LCO 3.1.4, Rod Group Alignment Limits, removes this requirement to declare a misaligned rod inoperable. This is because if the control rod is declared inoperable, the remaining rods in the affected control group must be aligned with the inoperable control rod or power must be reduced to equal to or less than 75% RTP within 1 hour. The licensee has proposed to delete the requirement to declare the rod inoperable if it is not restored to operable status within 1 hour, since if the option to align all rods in the affected control group is chosen, the rod is no longer inoperable because it is within alignment limits as required in both the existing TS and the improved TS. If the option to reduce power to equal to or less than 75% RTP is chosen, several additional actions are required including a verification that the accident analyses remain valid with the misaligned rod. Once this accident analysis verification has been completed, operation may continue but the rod condition remains "as is" or as previously stated in the existing TS as "inoperable". Therefore, an initial assumption in the safety analysis that directly affects core power distributions, and assumptions of available shutdown margin, remain unaffected. The NRC staff finds this change is an administrative restatement of the existing required actions to ensure that maximum rod misalignment requirements are met and is acceptable.

3. Existing TS 3.10.5 requirements for control rod position indication systems include the requirements for determining the control rod positions. Position indication of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Rod position indication is required to assess operability and misalignment. Existing TS 3.10.5.1 specifies that the rod position indication system and the step counters be operable and capable of determining the control rod positions within ± 12 steps. An action statement is included in improved TS 3.1.7, "Rod Position Indication," that specifies that the plant must enter 3.0.3, a forced shutdown immediately if more than one micro processor rod position indication per group are inoperable, or more than one demand position indicator per bank is inoperable. NUREG-1431 does not have a specific Condition for entry into LCO 3.0.3 as does proposed LCO 3.1.7, but it is implicit

from the generic LCO 3.0.3 discussion of requirements that LCO 3.0.3 would apply if the condition exists and the specific LCO does not cover it. This change is an administrative change, and is acceptable to the NRC staff.

4. Existing TS 3.10.5.2.a specifies that with a maximum of one rod position indication per bank inoperable, the rod position of non-indicating rods must be verified to be operable indirectly by the movable incore detectors with a Completion Time of once per 8 hours and immediately following motion of the rod that exceeds 24 steps since the last determination. Improved TS 3.1.7, "Rod Position Indication," requires a 4-hour Completion Time (instead of immediately) to verify rod position following rod motion that exceeds 24 steps. Rod position cannot be determined immediately; time is required to acquire data relevant to rod position and to obtain the results. The existing TS 3.10.5.2.a "Immediately" requirement is considered a start time and not a completion time. In improved TS 3.1.7, four hours provides an acceptable period of time to verify the rod positions while a reduction to equal to or less than 50% RTP will avoid undesirable power distributions that could result from continued operation at greater than 50% RTP with 2 or more rods misaligned. This change is consistent with the guidance in NUREG-1431 and is acceptable to the NRC staff.

5. The existing TS Table 4.1-1, Functional Units #1 and #2, requires a CHANNEL OPERATIONAL TEST (COT) on the power range and the intermediate range channels prior to startup if not done the previous week. The improved TS SR 3.1.8.1 has added new requirements to perform COT once within 7 days prior to reactor criticality while implementing Mode 2 physics test exceptions. These physics tests cannot be performed unless these channels are verified to be operable. The NRC staff finds the 7-day time limit is sufficient to ensure that the instrumentation is operable and properly set to provide accurate data and protection for initiating and conducting these physics tests.

The above changes are considered purely administrative changes in the statement of requirements in the improved TS, and are therefore acceptable.

3.3.1.2 Relocated Requirements

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate or reorganize all or portions of existing TS to other licensee-controlled documents, as listed below:

Existing TS	Title
3.2	Chemical and Volume Control System
3.10.1	Control Rod Insertion Limits
3.10.4	Control Rod Group Height
Figure 3.10-1	Control Rod Insertion Limits Versus Core Power
Figure 3.10-2	Coolant Boron Concentration (PPM) Shutdown Margin

The more significant changes resulting from relocating these items are as follows:

1. Existing TS 3.10.1.1 and Figure 3.10-2 together specify the coolant boron concentration existing versus shutdown margin required for one and two loop operation. The improved TS have administratively relocated these requirements to the COLR. The shutdown margin impacts uncontrolled boron dilution and steamline break accident analyses and is sensitive to many core related parameters such as control bank position, core power level, coolant temperature and other cycle specific parameters such as fuel burnup, xenon concentration, and boron concentration. The inclusion of shutdown margin in the COLR provides more flexibility in plant operation and in obtaining good fuel economics particularly for extended cycle operation. With the shutdown margin included in the COLR, the core design can be finalized after shutdown so that the actual end of cycle burnup is known. This knowledge is particularly helpful in evaluating the cause when the actual burnup differs from the projected value. This change is applicable for Ginna and it implements GL 88-16 under the guidance of NUREG-1431. The NRC staff finds this change does not affect nuclear safety because the determination of these limits is made using an approved methodology consistent with all applicable limits of the plant analysis as addressed in the UFSAR.

2. Existing TS 3.10.1.3 and existing Figure 3.10-1 specify, with a few exceptions, the control rod group insertion, sequence, and overlap limits. The improved TS have relocated these requirements to the COLR. This administrative change avoids unnecessary licensing delays for fuel cycle dependent variables for new fuel reloads. This change is applicable for Ginna and it implements GL 88-16 under the guidance of NUREG-1431. The NRC staff finds this change does not affect nuclear safety because the determination of these limits is made using an approved methodology consistent with all applicable limits of the plant analysis as addressed in the UFSAR.

3. Existing TS 3.10.4.3.2.b.iii, Control Rod Group Height, requires reevaluation of each accident listed in Table 3.10-1 within 5 days after a rod becomes misaligned as one of several required actions to allow operation to continue. Improved TS LCO 3.1.4, Rod Group Alignment Limits, Required Action B.6 requires that this reevaluation of accident analyses be performed to confirm whether the results remain valid under the new operating conditions. The list of accident analyses to be re-evaluated has been relocated to the TRM. This change is consistent with the guidance in the Final Policy Statement which allows the licensee to relocate or reorganize all or portions of existing TS to other licensee-controlled documents. The NRC staff has determined the existing TS Table 3.10-1 may only contain a partial list of accidents to be evaluated; however, the listing merely serves as an aid for consideration by the evaluator to bound the potential problem

created by a misaligned rod. Foremost, the NRC staff finds that the basic requirement to perform reevaluations and to verify that the accident analysis is valid, has remained unchanged.

4. The licensee proposes to relocate the following TS to the TRM: 1) existing TS 3.2.1 and existing TS 3.2.1.1 requirements for the boric acid injection flow paths during cold shutdown and refueling which specify the number of flow paths that must be operable; 2) existing TS 3.2.2 and existing TS 3.2.4 requirements for the boric acid injection flow paths above cold shutdown which specify the number of flow paths that must be operable; 3) existing TS 3.2.3 and Table 3.2-1, which are the requirements for the Boric Acid Storage Tank(s) which specify the boron concentrations, minimum volume and solution temperature; and, 4) existing TS Table 4.1-2, Functional Units #14, #16, and #19 requirements related to instrumentation for the boric acid storage tank, the chemical and volume control tank, and boric acid control. These systems and tanks are not assumed to be operable to mitigate the consequences of a DBA or transient. Additionally, they are not credited in the accident analysis and therefore do not meet the Final Policy Statement criteria for TS. These requirements were relocated to the TRM and future changes are controlled in accordance with 10 CFR 50.59. These relocated changes are consistent with the guidance of NUREG-1431 and are acceptable to the NRC staff.

5. The licensee proposed to relocate cycle specific variables to the COLR from the existing TS. The NRC staff evaluation of the acceptability of relocating existing TS limits to the COLR is discussed in Section IV of this evaluation.

The above relocated requirements relating to refueling operations are not required to be in the TS under 10 CFR 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. Further, they do not fall within any of the four criteria set forth in the Commission's Final Policy Statement, discussed in the Introduction above. The NRC staff concludes that the control of these provisions under 10 CFR 50.59 is acceptable, that the regulatory requirements provide sufficient control of these provisions, and that removing them from the TS is acceptable. Accordingly, the NRC staff has concluded that these requirements may be relocated from the TS to the licensee's TS Bases or the UFSAR, as applicable.

3.3.1.3 More Restrictive Requirements

By electing to implement Section 3.1 of NUREG-1431 specifications, the licensee proposed a number of conditions that are more restrictive than those required by the existing TS. The more significant conditions are as follows:

1. Existing TS 3.10.1 requirements were revised to include specific actions and completion times for cases when the shutdown bank insertion limits and the control bank insertion, sequence, and

overlap limits are not within the limits specified in the COLR (improved TS 3.1.5 and 3.1.6). These actions require verification within 1 hour that the shutdown margin is within limits and restoring the associated value to within limits within 2 hours or be in mode 3 within 6 additional hours. These additions were made to ensure that the control banks and the shutdown bank are available as assumed in the safety analyses.

2. Existing TS 3.10.1.1 requirements were revised to include a specific action to initiate boration within 15 minutes when the shutdown margin is not within limits in improved TS 3.1.1. The addition of this action ensures that shutdown margin is monitored and quickly restored within limits.

3. Existing TS 3.10.2.8, TS 3.10.2.9 and TS 3.10.2.10 requirements were revised to remove the physics test exceptions for axial flux difference (AFD). Ginna currently does not perform a physics test in Mode 1 which would require the exception of the AFD limits. Also, improved TS 3.2.3, which contains AFD is only applicable in Mode 1 with thermal power equal to or greater than 15% RTP.

4. Existing TS 3.10.4.1 requirements were revised to permit only low power physics test exceptions for control bank alignment. Ginna currently does not perform a physics test in Mode 1 which, as such, would require the exception of the alignment limits in the improved TS. Therefore, TS exceptions for Mode 1 physics testing are not included in the improved TS.

5. Existing TS 3.10.3.1.a, Control Rod Drop Time, requires the rod drop test to be performed with T_{avg} greater than or equal to 540°F. Performing this test ensures that the required negative reactivity insertion amount and rate resulting from a rod drop test via a reactor trip are within the values assumed in the safety analysis. Improved TS SR 3.1.4.4 has reduced the minimum T_{avg} for the rod drop test from 540°F to 500°F. The proposed 500°F temperature limit is conservative compared to the existing TS limit since the water will be slightly more dense at the lower temperature. This has the potential to slow the dropped rods slightly. The limiting time, however, must still be met. This change would also enable the plant to complete the rod drop test at an earlier time during plant startup. As soon as test conditions permit, the NRC staff finds that having earlier assurance this parameter is met before entering into higher modes of operations, enhances the safe conduct of operations at the plant.

6. Existing TS 3.10.4.4 requirements for control rod group height limits specifies actions to be in hot shutdown within 6 hours for the Condition when two or more rods are misaligned. Existing TS 3.10.4.4 was moved to improved TS 3.1.4, Rod Group Alignment Limits which includes an Action Statement to first verify the shutdown margin or initiate boration within 1 hour to restore the shutdown

margin when more than one rod is out of alignment. However, the requirement to go to Mode 2 with k_{eff} less than 1 in 6 hours were retained. The 1-hour Completion Time is a reasonable time because of the time required for potential xenon redistribution following the misalignment perturbation and the low probability of an accident during this time. The addition of this Action Statement to establish the shutdown margin is more restrictive, and is acceptable to the NRC staff.

7. Improved TS SR 3.1.6.1 requires verification within 4 hours prior to criticality that the critical control bank position is within limits in the COLR. The NRC staff finds that this new requirement to verify control bank position assures that rod banks not fully withdrawn are in the proper sequence and with the proper overlap limits and that sufficient reactivity will be available when criticality is achieved to shutdown.

8. A new surveillance requirement was added to improved TS 3.1.6, Control Bank Insertion Limits. During Modes 1 and 2, with k_{eff} greater than 1.0, a periodic verification every 12 hours was added to check that the sequence and overlap limits for control banks not fully withdrawn, are within the limits as specified in the COLR. The more frequent these various verifications are made, the less likely any control bank is outside of the insertion limits. The NRC staff finds this change further ensures that the control banks are within the assumptions of the accident analysis and that the withdrawn rods will meet the shutdown requirements.

9. A new surveillance requirement was added to improved TS 3.1.8, PHYSICS TESTS Exceptions - Mode 2. Improved TS SR 3.1.8.3 verifies every 30 minutes that thermal power is less than 5% RTP. Also if this requirement is not met, an immediate entry into Condition B is required. The NRC staff finds that verification of the thermal power level will ensure that the initial conditions of the safety analyses will continue to be met while performing the physics tests.

10. Existing TS Table 4.1-1, Functional Unit #4 requires a channel check once per shift. Improved TS SR 3.1.8.2 has added a new requirement to verify RCS temperature every 30 minutes while implementing Mode 2 physics test exceptions. Also, if this requirement is not met, an entry into Condition C is required to restore the RCS loop average temperature to within the limit. The NRC staff finds that more frequent verification of the RCS temperature during these tests will ensure that this initial condition will remain unchanged as is assumed in the safety analyses.

11. The licensee proposed new requirements in addition to those in existing Table 4.1-2 for verification of shutdown margin by adopting improved TS SR 3.1.1.1 requirements to verify every

24 hours that the shutdown margin is within limits. The SR frequency is based on the generally slow change in boron concentration and the low probability of an event occurring without the required SDM. This is a new TS requirement consistent with NUREG-1431.

12. Existing TS Table 4.1-2 was revised to add new surveillance requirements. Improved TS SR 3.1.3.1 requires verification prior to entering Mode 1 after each refueling that moderator temperature coefficient (MTC) is within the upper limit. This SR ensures that at the beginning of the fuel life that the MTC limit is negative when the thermal power is at RTP. The NRC staff find that limitations on MTC ensure that the value of this coefficient remains within the limiting conditions assumed in the UFSAR accident and transient analyses.

13. Existing TS Table 4.1-2 was revised to add new surveillance requirements. Improved TS SR 3.1.3.2 requires verification prior to entering Mode 1 after each refueling that MTC will be within the 70% RTP MTC upper limit and the end of life (EOL) lower MTC limit. This verification will ensure that the MTC is sufficiently negative in the higher power range to assure that power increases have a negative reactivity effect and is not too negative to cause a high overpower effect from a rapid cooldown, such as from a steam line break accident. The NRC staff finds that meeting the limit prior to entering Mode 1 ensures that the limit will also be met at higher power levels. This enhances the safe operation of the plant.

14. Existing TS Table 4.1-2 was revised to add new surveillance requirements. Improved TS SR 3.1.8.3 requires that the shutdown margin (SDM) is verified to be within limits every 24 hours while implementing the Mode 2 physics tests exceptions. The 24 hours frequency is based on the generally slow change in boron concentration and the low probability of an event occurring without the required SDM. This new SR is important because this LCO permits relaxation of selected existing LCO requirements to do the physics tests. The NRC staff finds this verification will ensure that sufficient negative reactivity is available to make the reactor subcritical if needed during the tests.

The NRC staff reviewed the above more restrictive requirements and concludes that they enhance the improved TS. Therefore, the more restrictive requirements are acceptable.

3.3.1.4 Less Restrictive Requirements

In electing to implement Section 3.3 specifications, the licensee proposed a number of conditions that are less restrictive than those that are allowed by the existing TS. The more significant conditions are as follows:

1. The existing TS 3.10.4.3.2.a, Control Rod Group Alignments, specifies requirements for restoring rods to within alignment limits within 1 hour. This option for restoring a rod to within its alignment position was removed from the LCO and added to the Bases for improved TS LCO 3.1.4, Rod Group Alignment Limits which are controlled under the improved TS 5.5.13, Bases Control Program. The licensee has always had the option to restore the correct alignment thereby exiting the degraded condition. All of the other Required Actions and allowed outage times of the existing TS have been retained unchanged in the improved TS. The NRC staff finds that under the guidance of NUREG-1431, the option to "restore to operable status" is implicit throughout the improved TS and thus continuing to restate this provision is unnecessary.

2. Existing TS 3.10.4.3.2.b and TS 3.10.4.3.2.c specify requirements for lowering the high neutron flux trip setpoint when power is reduced following a control rod misalignment. These TS were revised to remove the requirement to reduce the high neutron flux trip setpoints to equal to or less than 85% RTP when the power level is reduced to equal to or less than 75% RTP. This required action is deleted based on previous acceptance by the NRC staff. Additionally, the peaking factor limit verification within 72 hours and the reevaluation of the safety analysis within 5 days that are required by this specification provide further assurance that the assumptions made in the safety analysis are preserved.

3. The licensee proposed to extend the surveillance frequency of the control rod exercises from monthly to every 92 days for existing TS 4.1.2 and Surveillance Requirements in Table 4.1-2 for Functional Unit 6a. The 92-day frequency takes into consideration the other information available to the operator in the control room, and the channel check which is performed more frequently adds to the determination of rod operability. This surveillance interval is adequate considering the other rod position indication data available in the control room, the axial and radial flux distribution information, and results of the more frequent yet qualitative channel checks required by this surveillance frequency. This change is consistent with the guidance in NUREG-1431 and is acceptable to the NRC staff.

The staff finds that the above less restrictive requirements are acceptable, because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with current licensing practices, operating experience, and plant accident and transient analyses, and provide reasonable assurance that the public health and safety will be protected.

3.3.2 Power Distribution Limits

3.3.2.1 Significant Administrative Changes

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed administrative changes to bring the existing TS into conformance with NUREG-1431 improved TS. The more significant changes resulting from these administrative changes are as follows:

1. Existing TS 3.10.2.3 and TS 3.10.2.4 specify actions to ensure that the QPTR is maintained within limits. Improved TS LCO 3.2.4, "Quadrant Power Tilt Ratio (QPTR)" redefines existing TS 3.10.2.3 and 3.10.2.4 requirements to specifically define the applicability requirements for QPTR as Mode 1 with thermal power greater than 50% RTP. The improved TS applicability statement is consistent with the current requirements for Ginna since continued operation is not limited by QPTR when thermal power is less than 50% RTP. Below 50% RTP there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the QPTR. In addition, the existing TS QPTR LCO limit of 1.12 was removed since the primary limit of 1.02 will be reached initially and Actions will already be in progress to control the power tilt, and thermal power will continue to be reduced proportionally if the tilt ratio continues to increase. These changes are consistent with existing requirements and operating practices and are acceptable to the NRC staff.

The above changes are considered purely administrative changes in the statement of requirements in the improved TS, and are therefore acceptable.

3.3.2.2 Relocated Requirements

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate all or portions of existing TS to licensee-controlled documents as follows:

Existing TS	Title
3.10.2	Power Distribution Limits and Misaligned Control Rod

The more significant changes resulting from relocated items are as follows:

1. Existing TS 3.10.2.8 and 3.10.2.10.a requirements for controlling the axial flux difference to within ± 5% of the target flux difference are changed to relocate the AFD target band to the COLR. The COLR provides flexibility during the reload core design because the methodology for establishing the limits is specified in the COLR and therefore avoids unnecessary licensing delays while establishing cycle dependent variables during reload core design. The Applicability requirement of existing TS 3.10.2.8 was revised to clearly specify Mode 1 with thermal power greater than 15% RTP

versus a Mode of "except during physics tests, control rod exercises and excore detector calibration." This Applicability is acceptable because of the low amount of stored or transferred energy in the lower power Modes. The AFD at these lower power levels does not significantly affect the consequences of the design basis events. Additionally, the low signal current generated in the excore channels may preclude obtaining valid AFD signals below 15% RTP. These changes are consistent with existing TS 3.10.2.8, and are acceptable to the NRC staff.

2. Existing TS 3.10.2.2 contains the list of power distribution specific limits which are expressed as hot channel factors. The improved TS have relocated the limits for $F_Q(Z)$ (Heat Flux Hot Channel Factor) and $F^N_{\Delta H}$ (Nuclear Enthalphy Rise Hot Channel Factor) and the Figure 3.10-3 to the COLR. This change is consistent with the guidance provided in NUREG-1431. The COLR implements various limits by prior NRC staff review and approval of the methodology that specifies the procedure for establishing the cycle specific variables. The COLR methodology then becomes a requirement, and as long as the licensee follows the methodology in establishing the variable values, the values are acceptable without impacting safety. If the COLR process is changed, a request for a license amendment must be submitted and approved by the NRC staff before implementation. The NRC staff finds this change avoids unnecessary licensing delays while establishing cycle dependent variables during reload core design.

3. The licensee proposed to relocate cycle specific variables to the COLR from the existing TS. The NRC staff evaluation of the acceptability of relocating existing TS limits to the COLR is discussed in Section 4.0 of this evaluation.

The above relocated requirements relating to refueling operations are not required to be in the TS under 10 CFR 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. Further, they do not fall within any of the four criteria set forth in the Commission's Final Policy Statement, discussed in the Introduction above. The NRC staff concludes that the control of these provisions under 10 CFR 50.59 is acceptable, that the regulatory requirements provide sufficient control of these provisions, and that removing them from the TS is acceptable. Accordingly, the NRC staff has concluded that these requirements may be relocated from the TS to the COLR.

3.3.2.3 More Restrictive Requirements

By electing to implement Section 3.2 of NUREG-1431 specifications, the licensee proposed a number of conditions that are more restrictive than those required by the existing TS. The more significant conditions are as follows:

1. The licensee proposed to add several requirements for the condition when QPTR is not within the limit. The additional requirements are

as follows: a) A requirement to verify by calculation that the QPTR is within limits and limit power accordingly every 12 hours; b) A requirement to normalize the excore detectors prior to increasing RTP above the limits required in existing TS 3.10.2.3. This action is modified by a Note that requires verification that the hot channel factors are within limits prior to recalibration of the excore detectors; c) A requirement to verify F_Q (Heat Flux Hot Channel Factor) and $F^N_{\Delta H}$ (Nuclear Enthalpy Rise Hot Channel Factor) within limits either within 24 hours after reaching RTP or within 48 hours after increasing thermal power above the limit in existing TS 3.10.2.3. This action is modified by several Notes. The first Note clarifies that when the QPTR alarm is due to instrumentation alignment this action does not need to be completed. The second Note allows this action to be completed only after the excores have been recalibrated. The third Note clarifies that the Completion Time applicable first is the one that must be met; d) A requirement to reduce power to less than 50% RTP within 4 hours if the initial Required Actions are not met within the associated completion time. This takes the plant out of the Applicability when the actions are not met and provides an additional action before plant shutdown is required.

2. Existing TS 3.10.2.1 specifies the use of the movable incore detectors or core exit thermocouples to measure the QPTR once a day if operating above 75% RTP with one excore channel out of service. This requirement was revised to delete the use of core exit thermocouples to verify QPTR and replaced with improved TS SR 3.2.4.3 to perform a flux map daily to verify that hot channel factors are within limits. The incore detectors are not used to verify QPTR but rather to verify that the core peaking factors are acceptable. The core peaking factors serve as the basis for core parameters limits assumed in the accident analysis. Ginna does not have the 8 pairs of symmetric thimble plugs necessary to perform partial flux mapping and thus is required to complete a full core flux map to verify that the core power distribution is acceptable. This change eliminates one option for establishing that core parameters are met, however, it is consistent with existing Ginna practices for meeting TS and is acceptable.

3. Existing TS 3.10.2.2 specifies actions to ensure that hot channel factors are met. The existing TS actions were revised to include an action to reduce the acceptable AFD operational limits setpoints specified in the COLR by the percentage that F_Q exceeds the limit. The requirement is included in LCO 3.2.1, Heat Flux Hot Channel Factor ($F_Q(Z)$). This action is necessary since a change in F_Q can adversely impact AFD limits, i.e. reduce the range of acceptable AFDs. The control of the AFD ensures that the core peaking factors are not excessive. The Completion Time of 8 hours to perform this action is sufficient considering the concurrent requirement to reduce thermal power before the setpoints are reduced and the small

likelihood of a transient during this time. This change adds a new requirement and is acceptable.

4. Existing TS 3.10.2.2 specifies actions to ensure that hot channel factors are met. The improved TS LCO 3.2.1, Heat Flux Hot Channel Factor ($F_Q(Z)$), has added a new Condition to provide additional requirements when hot channel factors not are met. Condition B requires that the plant be placed in Mode 2 in 6 hours if the initial Required Actions of Condition A are not met within the associated Completion Time. This takes the plant out of the LCO applicability when the actions are not met and provides an additional action before plant shutdown is required. The Completion Time of 6 hours is sufficient to reach Mode 2 from full power operation in an orderly manner without challenging plant systems. These changes are consistent with the guidance of NUREG-1431 and this places the plant in an operating condition where these LCO requirements do not apply. The NRC staff finds this is a more restrictive approach for controlling power distribution and thus ensures the continued safe conduct of operations at the plant.

5. Existing TS Table 3.5-1, Functional Unit #16, "Quadrant Power Tilt Monitor," used for measuring quadrant power tilt and for controlling the QPTR is moved to improved TS LCO 3.2.4, "Quadrant Power Tilt Ratio (QPTR)" with the QPTR Monitor operability requirements. In addition, requirements were added to verify every 24 hours by calculation that the QPTR is within limits when the Quadrant Power Tilt Monitor is inoperable and thermal power is less than 75% RTP. Requirements were also added to verify every 24 hours with a full core flux map that the core power distribution is acceptable when the Quadrant Power Tilt Monitor is inoperable and thermal power is equal to or greater than 75% RTP. These added requirements are more restrictive and are acceptable.

6. The licensee proposed to adopt the requirement of improved TS SR 3.2.4.2 that requires verification that the QPTR is within limits every 7 days by calculation using at least three-out-of-four operable power range channels when thermal power is less than 75% RTP. This requirement is not currently in existing TS Table 4.1-1. With the addition of SR 3.2.4.1, the ability to detect large tilts with only three channels remains; but the capability to detect small power tilts in some quadrants is decreased. Therefore, if thermal power is equal to or greater than 75% RTP and one power range channel is inoperable, then SR 3.2.1.2 and SR 3.2.2.2 must additionally be performed because a full core map should be used to verify QPTR in this degraded state. The NRC staff finds SR 3.2.4.2 provides an accurate alternative to a full core flux map for ensuring the F_Q and $F^N_{\Delta H}$ remain within limits and the core power distribution is consistent with the safety analyses.

7. Existing TS 3.10.2.2 power distribution limits requirements were revised to remove the low power physics tests exception since new

LCO 3.2.1 and LCO 3.2.2 which contain the peaking factor requirements are only applicable in Mode 1. Ginna currently does not perform a physics test below Mode 1 which would require an exception to the power distribution limits.

8. Existing TS 3.10.2.3 requirements were revised to remove the physics test exceptions for the QPTR. Ginna currently does not perform a physics test in Mode 1 which would require the exception of the QPTR limit. Also, the improved TS 3.2.4 which contains QPTR, is only applicable in Mode 1 with thermal power equal to or greater than 50% RTP.

9. The Applicability requirement of existing TS 3.10.2.8 was revised to remove the physics test exceptions for AFD and by clearly specifying Mode 1 with thermal power greater than 15% RTP versus a Mode of "except during physics tests, control rod exercises or excore detector calibration." This Applicability is acceptable because of the low amount of stored or transferred energy in the lower power Modes. The AFD at these lower power levels does not significantly affect the consequences of the design basis events. Additionally, the low signal current generated in the excore channels may preclude obtaining valid AFD signals below 15% RTP.

10. Existing TS 3.10.2.4 and TS 3.10.2.5 specify actions to restrict operations when the QPTR is not within limits. Improved TS LCO 3.2.4, Quadrant Power Tilt Ratio (QPTR), added a new Condition to provide additional requirements when QPTR is not within limits. Condition B requires that thermal power be reduced to equal to or less than 50% RTP in 4 hours if the initial Required Actions of Condition A are not met within the associated Completion Times. This takes the plant out of the LCO applicability when the actions are not met and provides an additional action before plant shutdown is required. The Completion Time of 4 hours is sufficient to reach equal to or less than 50% RTP from full power operation in an orderly manner without challenging plant systems. These changes are consistent with the guidance of NUREG-1431 and this places the plant in an operating condition where these LCO requirements do not apply. The NRC staff finds this is a more restrictive approach for controlling power distribution and thus ensures the continued safe conduct of operations at the plant.

11. Existing TS 3.10.2.7 requires the target flux difference be measured at least once per equivalent full power quarter. Improved TS SR 3.2.3.4 retains this requirement but additionally requires the target flux difference be initially measured once within 31 effective full-power days (EFPD) after each refueling. This new requirement is further clarified by a Note that allows the predicted beginning of cycle AFD from the cycle nuclear design to be used to determine the initial target flux difference after each refueling. Even though the target flux difference varies slowly with core burnup, the NRC staff finds this more restrictive

requirement ensures core operating performance is verified reasonably soon after startup, rather than waiting for the first quarterly surveillance, as is permitted by the existing TS requirements.

The NRC staff reviewed the above more restrictive requirements and concludes that they enhance the improved TS. Therefore, the more restrictive requirements are acceptable.

3.3.2.4 Less Restrictive Requirements

In electing to implement the Section 3.2 specifications, the licensee proposed a number of conditions that are less restrictive than those that are allowed by the existing TS. The more significant conditions are as follows:

1. Existing TS 3.10.2.1 requires the use of the movable incore detectors to measure the power distribution after each refueling prior to operation of the plant at 50% RTP. Existing TS 3.10.2.1 requirements were changed to require measurement of the power distribution after each fuel reloading prior to operation of the plant at or above 75% RTP instead of prior to 50% RTP consistent with improved TS SR 3.2.1.1 and SR 3.2.2.1. The original requirement to measure the power distribution prior to 50% RTP during plant startup was based on engineering judgement and the desire to verify, prior to reaching RTP, that the design limits will not be achieved.

   The improved TS requirement continues to ensure that the fuel design limits are not exceeded when RTP is achieved. The peaking factors are a function of the power level and at reduced power levels, the peaking factor limits are increased based on the associated power multiplication factor. Therefore, the closer the plant is to RTP conditions during the performance of the power distribution measurements, then the more meaningful the measurement will be with respect to actual RTP conditions. Requiring this surveillance at 75% versus 50% still provides the necessary margin to ensure that design safety limits are not exceeded and provides the operator with more flexibility during power ascension following a refueling.

2. Existing TS 3.10.2.2 specifies actions to ensure that hot channel factors are met at all times, i.e., during all modes and specified conditions. The requirements were revised to require that the hot channel factors be within limits only in Mode 1. These requirements were placed in improved TS LCO 3.2.1. The Applicability of LCO 3.2.1, "Heat Flux Hot Channel Factor, (F_Q)" and LCO 3.2.2 "Nuclear Enthalpy Rise Hot Channel Factor, ($F_{\Delta H}$)" does not require the F_Q or $F_{\Delta H}$ limits to be met in Modes 2 - 5 or during refueling. As described in the improved TS LCO 3.2.1 Bases, F_Q and $F_{\Delta H}$ must be within limits during Mode 1 to ensure that the core peaking factors are not excessive; however, such limits are

not necessary in Mode 2 because there is insufficient stored energy in the fuel or being transferred to the coolant to require these limits be in effect to ensure that fuel thermal limits are met. The limits are not required to be met below Mode 2 since the reactor is not critical. This change is therefore acceptable to the NRC staff.

3. Existing TS 3.10.2.2 specifies actions to ensure that hot channel factors are met. The requirements of existing TS 3.10.2.2 are located in improved TS 3.2.1, "Heat Flux Hot Channel Factor (Fq(Z))" and revised to allow a Completion Time of 72 hours (instead of 24 hours) to reduce the Overpower ΔT and the Overtemperature ΔT trip setpoints when F_Q or $F_{\Delta H}$ are not within limits, consistent with the guidance of NUREG-1431. LCO 3.2.1 also includes a Completion Time of 72 hours to reduce the Power Range Neutron Flux High trip setpoints. They provide further protection against the consequences of severe transients with unanalyzed power distributions. The 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the initial prompt reduction in thermal power equal to at least 1% reduction for each 1% over safety limit.

4. Existing TS 3.10.2.3 specifies actions to ensure that QPTR is maintained within limits. Improved TS LCO 3.2.4, "Quadrant Power Tilt Ratio (QPTR)" redefines existing TS 3.10.2.3 to limit the thermal power relative to the percentage of reactor core quadrant power tilt, (i.e., limits power to 3% below RTP for each 1% by which the QPTR exceeds 1.00) instead of requiring an immediate power reduction to below 75% RTP. The existing TS requirement to reduce power to 75% RTP is essentially equivalent to a 2% RTP reduction for each 1% the QPTR exceeds 1.00 until QPTR reaches 1.12 where a reduction to 50% RTP is required. The change will avoid unnecessary power reductions, which are replaced with requirements for successive compensating power reductions as determined by the reactor core tilt ratio until power tilt no longer exists. The proposed change provides flexibility with the initial power reduction, but requires instead at least a 3% RTP reduction for each 1% QPTR exceeding balanced conditions, a QPTR of 1.00. Thus, the proposed change while requiring a smaller reduction for small tilts is more conservative for larger tilts which are a more significant safety problem. This revision is consistent with current industry practice. The Completion Time requirement for measuring the hot channel factors when QPTR exceeds 1.02 is changed to 24 hours from 2 hours since the thermal power is reduced appropriately within 2 hours. The 24-hour Completion Time takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and obtain a flux map. These changes are consistent with the guidance of NUREG-1431, and do not significantly affect plant safety, and are acceptable to the NRC staff.

5. Existing TS 3.10.2.4 specifies actions to restrict operations when the QPTR exceeds 1.02 but is less than 1.12 or recurs intermittently without known cause. Improved TS LCO 3.2.4, "Quadrant Power Tilt Ratio," does not contain a requirement to identify the cause of the reactor core tilt or to limit power to less than 50% RTP. Identification of the cause of the tilt is not always possible. However, other compensatory actions (e.g., surveillances) and TS limits are required to be met and are sufficient to maintain continued safe operation of the plant by ensuring continued protection of the core with adequate margin. This change is consistent with the guidance of NUREG-1431, and is acceptable to the NRC staff.

6. Existing TS 3.10.2.5 specifies actions to implement power reductions when QPTR cannot be reduced to within limits in the time allotted. Existing TS 3.10.2.5 requirements were deleted because the 1.12 QPTR limit is reduced to 1.02 in improved TS 3.2.4 and the applicability requirement for QPTR has been revised to greater than 50% RTP. Appropriate operating constraints are imposed on improved TS if QPTR is not met by setting power reductions at 3% below RTP for each 1% QPTR is exceeded in order to control the power tilt. This change is acceptable to the NRC staff based on the requirements to reduce thermal power and to perform core peaking factor measurements to ensure the assumptions of the accident analysis are met for core parameters.

7. Existing TS 3.10.2.12 requires that the axial flux difference be logged hourly for the first 24 hours and hourly thereafter when the control room axial flux difference alarm is out of service. This was revised to require a verification that the AFD is within limits every 12 hours and to log the AFD once every hour with thermal power less than 90% RTP when the AFD monitor alarm is inoperable instead of every hour for the first 24 hours and every half hour thereafter. At power levels less than 90% RTP, but greater than 15% RTP, the Surveillance Frequency is reduced to one hour because the AFD may deviate from the target band for up to one hour. Using the methodology to calculate cumulative penalty deviation time before corrective action is required. The NRC staff find this acceptable because other provisions are in place to assure that the AFD limits are not exceeded.

The less restrictive requirements are acceptable, because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with current licensing practices, operating experience, and plant accident and transient analyses. They give reasonable assurance that the public health and safety will be protected.

3.3.3 Instrumentation

3.3.3.1 Significant Administrative Changes

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed administrative changes to bring the existing TS into conformance with NUREG-1431 improved TS. The more significant changes resulting from the administrative items are as follows:

1. Existing TS Table 3.5-1 contains the reactor trip functions for Ginna and the number of required channels for each function. The trip setpoints for these are provided in existing TS 2.3.1 while the surveillance requirements are provided in existing TS Table 4.1-1. These requirements were moved to improved TS LCO 3.3.1. The format of the existing TS was also changed to be consistent with NUREG-1431 by removing table columns 1 (Total number of Channels) and 3 (Minimum operable Channels) and replacing them with a new column denoting "Required Channels." The improved TS LCO now provides required action if one or more "required channels" are inoperable for each function. Various design details contained in the existing TS also not retained following this change since the "required channel" column format does not require, nor support, this level of detail. Instead, these details are provided in the Bases, UFSAR, or other documents which are controlled by 10 CFR 50.59. The Mode of Applicability for each function was also changed to reflect the new Mode definitions. The presentation of these requirements are retained in the improved TS. Any more restrictive or less restrictive changes following this relocation are discussed below.

2. Existing TS Table 3.5-2 contains the ESFAS functions at Ginna and the number of required channels for each function. The trip setpoints and allowable values for each function are provided in Table 3.5-4 while the surveillance requirements are provided in existing TS Table 4.1-1 and 4.1-2, TS 4.4.6.1 and TS 4.8.9. These requirements were moved to improved TS LCO 3.3.2. The format of the existing TS was also changed to be consistent with NUREG-1431 by removing table columns 1 (Total number of Channels) and 3 (Minimum operable Channels) and replacing them with a new column denoting "Required Channels." The improved TS LCO now provides required action if one or more "required channels" are inoperable for each function. Various Design details contained in the existing TS are also not retained following this change since the "required channel" column format does not require, nor support, this level of detail. Instead, these details are provided in the Bases, UFSAR, or other documents which are controlled by 10 CFR 50.59. The Mode of Applicability for each function was also changes to reflect the new Mode definitions. The presentation of these requirements retained in the improved TS.

3. Existing TS Table 3.5-1 contains the 480-Vac Loss of Power diesel generator start functions for Ginna and the number of required channels for loss of voltage and degraded voltage. The relay setpoints for these channels is provided in existing TS Table 4.1-1. These requirements were moved to improved TS LCO 3.3.4. Any more restrictive or less restrictive changes following this relocation is discussed below.

4. Existing TS 2.3.2.1 has a Note that during cold rod drop tests, the pressurizer level high trip may be bypassed. Improved TS Table 3.3.1-1, Function 8, requires that this trip be functional in Modes 1 and 2 while improved TS SR 3.1.4.4 requires the rod drop test to be performed prior to criticality (i.e., Mode 2). Therefore, the bypass of the Pressurizer Level - high trip during cold rod drop tests is no longer necessary since the rod drop test must be performed prior to reaching the pressurizer level - high trip Function Mode of Applicability. This is an administrative change, and is, therefore, acceptable.

5. Existing TS 2.3.2.1 requires removing the bypass of reactor coolant flow low trip at greater than 8.5% reactor thermal power when in two-loop operation. By contrast, improved TS, Table 3.3.1-1, Function 9.b (footnote h), requires that the reactor coolant flow low trip is functional in Mode 1 with at least 8.5% reactor thermal power for two-loop operation (with the reactor coolant flow low, single-loop trip [Function 9.a] blocked). The presentation of these requirements is an administrative change, with the requirements retained in the improved TS. The change is, therefore, acceptable.

6. Existing TS 2.3.2.2 requires removing of the bypass of single-loop reactor coolant flow low trip at greater 50% reactor thermal power. By contrast, improved TS, Table 3.3.1-1, Function 9.a (footnote f, requires that reactor coolant flow low trip is functional in Mode 1 at with at least 50% reactor thermal power for single-loop operation. The presentation of these requirements is an administrative change, with the requirements retained in the improved TS. The change is, therefore, acceptable.

7. Existing TS 3.5.6.1 requires instrumentation to monitor control room heating ventilation and air conditioning (HVAC) instrumentation setpoints, including particulates equal to or less than 1×10^{-8} μCi/cc, iodine equal to or less than 9×10^{-9} μCi/cc, and noble gases equal to or less than 1×10^{-5} μCi/cc. Existing TS Table 4.1-2, Functions 34 and 35 contain the associated surveillance requirement. Improved TS Table 3.3.6-1 includes requirements for these instruments, as well as their setpoints, actuation logic and relays, and manual initiation. The presentation of these requirements is an administrative change, with the requirements retained in the improved TS. The change is, therefore, acceptable.

8. Existing TS Table 3.5.1, Functional Unit 20, "Automatic Trip Logic Including Reactor Trip Breakers," is moved to improved TS Table 3.3.1-1, Functional Unit 17, "Reactor Trip Breakers," (including any reactor trip bypass breakers racked in and closed for bypassing a reactor trip breaker); Functional Unit 18, "Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms"; and Functional Unit 19, "Automatic Trip Logic." These requirements are reformatted to separately denote the reactor trip breakers (RTBs), the RTB undervoltage shunt trip mechanisms, and automatic trip logic functions. The presentation of these requirements is an administrative change, with the requirements retained in the improved TS. The change is, therefore, acceptable.

9. Existing TS Table 3.5-4, Functional Unit 7.a, "Loss of Voltage, 480-Vac Safeguards Bus Undervoltage (Loss of Voltage)," is moved to improved TS SR 3.3.4.2. Existing TS Table 3.5-4, Functional Unit 7.b, "Loss of Voltage, 480-Vac Safeguards Bus Undervoltage (Degraded Voltage)," is moved to the improved TS SR 3.3.4.2. The allowable values and trip setpoints for SR 3.3.4.2 are derived from the existing TS, Figure 2.3-1, as revised to provide specific voltage and time values instead of relay curves.

   Existing TS 2.3.3.1 and 2.3.3.2, respectively, define the loss of power and degraded voltage settings in conjunction with the limits shown in Figure 2.3-1, "measured" and "acceptable" values, respectively. The evaluation converting the degraded voltage and loss of voltage values from Figure 2.3-1 to defined voltage setpoints and time delays is documented in RG&E Design Analysis, DA-EE-93-006-08, "480-V Undervoltage Relay Settings and Test Acceptance Criteria." Since this analysis determines the actual field settings and testing parameters, ensuring that existing TS Figure 2.3-1 is always met, incorporating these values in the improved TS versus the Figure is acceptable. The presentation of these requirements is an administrative change with the requirements retained in the improved TS. The change is, therefore, acceptable.

10. Existing TS 2.3.2.2 allows removing the bypass of the single loss-of-flow trip at equal to or less than 50% of rated thermal power, thus enabling the Reactor Coolant Flow-Low (Two Loops) trip function. Improved TS Table 3.3.1-1, footnote g, "Thermal Power equal to or greater than 50% RTP," applies to Functional Unit 9.a, "Reactor Coolant Flow — Low, (Single Loop)." Table 3.3.1-1, footnote h, "Thermal Power equal to or greater than 8.5% RTP and Reactor Coolant Flow — Low (Single Loop) Trip Function Blocked," applies to Functional Unit 9.b, "Reactor Coolant Flow — Low, (Two Loops)."

    The trip function for "Reactor Coolant Flow — Low, (Single Loop)" is blocked above 50% power, as single loop operation is allowed only when below that power level. However, with that block, the

Function 9.b trip (Reactor Coolant Flow — Low, (Two Loops)) must be in place to provide the protective action should the flow of either loop fall below 90% of nominal loop flow while above 50% reactor thermal power. The function for "Reactor Coolant Flow — Low, (Single Loop)" trips when both loops fall below 90% of nominal loop flow while below 50% reactor thermal power. The improved TS tie the Mode of Applicability for the Reactor Coolant Flow — Low (Two Loops) into the Single Loop Trip (i.e., you must have at least one of these trip functions operable above 8.5% RTP. The presentation of these requirements provides clarification, and is an administrative change with the requirements retained in the improved TS. The change is, therefore, acceptable.

11. The setpoints for the intermediate range neutron flux, source range neutron flux, undervoltage bus 11A and 11B, and turbine trip — low autostop oil pressure are not included in improved TS Table 3.3.1-1 (Functional Units 3, 4, 11, and 14.a, respectively), since these setpoints are not in the existing TS. Additionally, it is noted that these are anticipatory functions, which are not explicitly credited in the accident analyses. That is, these functions are credited as a backup for conservatism and uncertainty considerations, but are not modeled within the analyses using an actual trip setpoint. The setpoints for these trip functions are contained within numerous documents within RG&E, including station procedures (such as calibration and setpoint procedures), the UFSAR (Section 7.2.2.2), and the Setpoint Study Program. The affected procedures and the UFSAR are controlled under 10 CFR 50.59, while the Setpoint Study Program requires notification of a setpoint change. RG&E considers this sufficient control of the setpoints. Because these unspecified setpoints for these functional units are a carryover from the existing TS and licensing Bases, this is an acceptable administrative change.

12. Existing TS 3.5.3 addresses accident monitoring instrumentation. The associated surveillance requirements are provided in existing TS Table 4.1-3. These were moved to improved TS LCO 3.3.3. Within this context, existing TS 3.5.3.1 requires the instrumentation identified in Table 3.5-3 whenever the reactor is in or above hot shutdown. In addition, existing TS 3.5.3.2 requires action if the number of operable channels is less than specified in Table 3.5-3. The columns for Total Required Number of Channels and Minimum Channels operable are not included for the functional units of improved TS Table 3.3.3-1. Instead, the columns are replaced with a new column denoting Required Channels. The presentation of these requirements is an administrative change, with the requirements retained in the improved TS. The change is, therefore, acceptable.

The above changes are considered purely administrative changes in the statement of requirements in the improved TS, and are, therefore, acceptable.

3.3.3.2 Relocated Requirements

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate or reorganize all or portions of existing TS to other licensee-controlled documents.

Existing TS	Title
3.5.4	Instrumentation Systems
3.12.1	Movable In-Core Instrumentation
Table 3.5-1	Protection System Instrumentation
Table 3.5-2	Engineered Safety Feature Actuation Instrumentation
Table 3.5-6	Post-Accident Radiation Monitoring Instrumentation
Table 4.1-2	Minimum Frequencies for Equipment and Sampling Tests

The more significant changes resulting from relocated items are as follows:

1. In conjunction with Table 3.5-6, existing TS 3.5.4 specifies the operability conditions for certain radiation accident monitoring instrument channels. The requirements for radiation accident monitoring instrumentation, provided to monitor radiation levels in selected plant locations following an accident, are not incorporated in the improved TS. No screening criteria apply for these requirements, since the monitored parameters are not part of the primary success path in the mitigation of a DBA or transient. These instruments are neither used for, nor capable of, detecting a significant abnormal degradation of the reactor coolant pressure boundary before a DBA. Therefore, the requirements specified for these functions do not satisfy the technical specification screening criteria in the Commission's Final Policy Statement, and they are moved to the ODCM. Further, these instruments are not Regulatory Guide 1.97, Type A or Category 1, instrumentation. Thus, they can be excluded from the improved TS by NRC policy. Therefore, this relocation to the ODCM is acceptable.

2. Existing TS 3.5.6.1 controls instrumentation that monitors the control room ventilation instrumentation for Cl_2 and NH_3 (chlorine and ammonia). Existing TS Table 4.1-1, Functions 34 and 35 provide the associated surveillance requirements. Improved TS Table 3.3.5-1 does not include requirements for Cl_2 and NH_3 instrumentation that monitors control room habitability. No screening criteria apply for these requirements, since the monitored parameters are not part of the primary success path in the mitigation of a DBA or transient. These monitors are neither used for, nor capable of, detecting a significant abnormal degradation of the reactor coolant pressure boundary before to a DBA. Therefore, the requirements specified for these functions do not satisfy the technical specification screening criteria in the Commission's Final Policy Statement, and are relocated to the TRM. This relocation to the TRM is acceptable.

3. Existing TS Table 3.5-1, Functional Unit 17.a, "Circulating Water Condenser Flood Protection," and Functional Unit 17.b, "Circulating Water Screenhouse Flood Protection," are relocated to the TRM. Existing TS Table 4.1-2, Functional Unit 19 contains the associated surveillance requirements. The trip function requirement for the circulation water flood protection is not included in the improved TS. The circulation water flood protection instruments only provide an anticipatory turbine trip that is not assumed in the Ginna safety analyses. These instruments do not monitor parameters that express initial assumptions for a DBA or transient, do not identify a significant abnormal degradation of the reactor coolant pressure boundary, and do not provide any mitigation of a design-basis event. Therefore, the requirements specified for these functions do not satisfy the technical specification screening criteria in the Commission's Final Policy Statement, and are relocated to the TRM and UFSAR. This relocation is acceptable.

4. Existing TS 3.12.1 requires a minimum of two thimbles per quadrant, and sufficient operable movable incore detectors during calibrations of the excore axial offset detection system. Improved TS SR 3.3.1.6 requires a calibration of the excore channels to the incore detector measurements every 92 full power days or equivalent. The requirement for the number of thimbles per quadrant required for operable status during recalibration of the excore axial offset detection system is not included in the improved TS. The requirements for this surveillance are not an initial assumption of any DBA or transient analysis. Therefore, this specification does not satisfy the technical specification screening criteria in the Commission's Final Policy Statement, and is relocated to the TRM. This relocation is acceptable.

5. Existing TS Table 3.5-2, for the standby motor-driven AFW pumps, requires the restoration of an inoperable channel within 48 hours, if the total number of operable channels is one less than the required minimum number of channels. The requirements for manual initiation of the standby auxiliary feedwater pumps are not included in the improved TS.

   The individual standby AFW pump instrumentation requirements provide manual control of the standby AFW pumps that provide backup capability for the AFW pumps. The Ginna safety analyses do not model the individual manual functions for these pumps. These instruments do not monitor parameters that are initial assumptions for a DBA or transient, do not identify a significant abnormal degradation of the reactor coolant pressure boundary, and do not provide any analyzed mitigation of a design-basis event. Therefore, the requirement specified for this function does not satisfy the technical specification screening criteria in the Commission's Final Policy Statement and is relocated to the TRM. This relocation is acceptable.

6. Existing TS Table 4.1-2, Functional Unit #10 is relocated to the TRM. Functional Unit #10 contains the refueling system interlocks minimum frequency for equipment and sampling tests. The requirement to verify refueling system interlocks is not assumed in the Ginna Station safety analyses. The interlocks do not monitor parameters that express initial assumptions for a DBA or transient, do not identify a significant abnormal degradation of the reactor coolant pressure boundary, and do not provide any mitigation of a design-basis event. Therefore, the requirement specified does not satisfy the technical specification screening criteria in the Commission's Final Policy Statement, and is relocated to the TRM. This relocation is acceptable.

The above relocated requirements related to installed plant instrumentation are not required to be in the TS under 10 CFR 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. Further, they do not fall within any of the four criteria set forth in the Commission's Final Policy Statement, as discussed in the Introduction above. In addition, the NRC staff finds that sufficient regulatory controls exist under 10 CFR 50.59. Accordingly, the NRC staff concludes that these requirements may be relocated from the TS to the licensee's TS Bases, COLR, or UFSAR, as applicable.

3.3.3.3 More Restrictive Requirements

By electing to implement Section 3.3 of NUREG-1431 specifications, the licensee proposed a number of conditions that are more restrictive than those required by the existing TS. The more significant conditions are as follows:

1. Existing TS 2.3.3.1 requires the 480-Vac safeguards bus loss-of-voltage relays to operate in equal to or less than 8.5 seconds for a voltage of equal to or less than 368-Vac. Existing TS 2.3.3.2 requires the 480-Vac safeguards bus degraded voltage relays to operate at voltages equal to or less than 414-Vac and greater than 368-Vac. Improved TS SR 3.3.4.2 provides the allowable values, setpoints, and time delays for the loss-of-voltage and the degraded voltage relays. The allowable value for the loss of voltage relays is greater than 368-Vac @ equal to or less than 275 seconds, the trip setpoint is greater than 372.8-Vac @ equal to or less than 2.4 ± 0.12 seconds. The allowable value for the degraded voltage relays is greater than 414-Vac @ equal to or less than 1520 seconds, the trip setpoint is greater than 419.2-Vac @ equal to or less than 1520 seconds.

   The limiting safety system settings for the loss-of-voltage and degraded voltage functions provide a minimum trip setpoint value. RG&E Design Analysis, DA-EE-93-006-08, "480-V Undervoltage Relay Settings and Test Acceptance Criteria," determines the actual field and testing setpoints to ensure that the requirements in existing TS Figure 2.3-1 are always met. Criteria for establishing equivalent values based on measured voltage (versus relay operating

time) are relocated to the Bases for LCO 3.3.4. This more restrictive change is acceptable.

2. Existing TS 3.5.6.2 does not require contingent actions if the specified actions to restore the detection systems are not completed as required. By contrast, improved TS 3.3.5, Conditions B and C, require contingent actions if the required control room emergency air treatment system (CREATS) actions are not met. These actions are to shutdown to Mode 5 initiate action to restore the inoperable channel to operable status, suspend core alterations, and suspend movement of irradiated fuel assemblies. These new requirements specify required actions for various modes of operation when the CREATS isolation dampers cannot be placed in the emergency radiation protection mode. These more restrictive requirements are acceptable.

3. Improved TS Table 3.3.1-1, Functional Unit 10, adds RTS requirements for reactor coolant pump (RCP) Breaker Position, single-loop operation, and two-loop operation. These functions anticipate the Reactor Coolant Flow — Low trips by monitoring each RCP breaker position to avoid reactor coolant system heatup that occurs in the time between the RCP trip and the low flow trip. The function ensures that protection is provided against violating the DNBR limit because of a loss of flow in either a single-loop or two-loop configuration. Therefore, this more restrictive change is acceptable.

4. Improved TS Table 3.3.1-1, Functional Unit 15, adds requirements for a reactor trip on a safety injection input from ESFAS. If a reactor trip has not already been generated by the RTS, this function ensures that the ESFAS automatic actuation logic will initiate a reactor trip upon any signal that initiates a SI. A reactor trip is initiated every time an SI signal is present. Therefore, this more restrictive change reflecting the plant design is acceptable.

5. Improved TS Table 3.3.2-1, Functional Units 1.b, 2.b, 3.b 4.b, 5.a, and 6.a adds requirements for the automatic actuation logic and actuation relays for the ESFAS instrumentation. Respectively, these functional unit requirements relate to actuation of a safety injection, containment spray, containment isolation, steam line isolation, feedwater isolation, and auxiliary feedwater. These new requirements are more restrictive than the present specifications.

   Actuation logic consists of all circuitry housed within the actuation subsystems, including relay contacts responsible for actuating the engineered safety features equipment. This logic circuitry is assumed within the operability of the specific functions. Additionally, the automatic actuation logic and actuation relays for various functions are required to be operable in Mode 3 and above (Mode 4 for the containment spray containment

isolation and safety injection) to support system-level initiation. These changes provide a more complete LCO requirement for each ESFAS function. Therefore, these more restrictive change are acceptable.

6. Existing TS Table 3.5.1, Functional Unit 18, requires the loss-of-voltage relays for the 480-Vac safeguards buses to be operable whenever the RCS temperature equal to or greater than 350°F. Similarly, existing TS Table 3.5.1, Functional Unit 19, requires the degraded voltage relays for the 480-Vac safeguards buses to be operable whenever the reactor coolant temperature is equal to or greater than 350°F.

   Improved TS 3.3.4 ties the applicability of these relays to the diesel generator operability requirements, rather than RCS temperature. The applicability is also revised, requiring the instruments to be operable in all modes associated with diesel generator operability. This ensures that the diesel generator can perform its function on a loss-of-voltage or degraded voltage to the 480-Vac safeguards buses. Therefore, these more restrictive changes are acceptable.

7. Existing TS Table 3.5-3 is replaced with improved TS Table 3.3.3-1, which addresses requirements and conditions for post-accident monitoring instrumentation, including Regulatory Guide 1.97, Type A and Category I variables. These functions are denoted in UFSAR Table 7.5-1. The presentation of these requirements adds instrumentation not included in existing TS Table 3.5-3. The additional instrumentation requirements are more restrictive and are acceptable.

8. The frequencies of SR 3.3.1.3 and SR 3.3.1.6 (for the overtemperature ΔT) are "revised consistent with Ginna practices." SR 3.3.1.3 is not required within the existing TS, but SR 3.3.1.6 is addressed by existing TS 3.12.1. Ginna presently performs these two surveillances as described by the improved TS surveillance requirements and their associated Bases. These surveillances are implemented and controlled by station procedures. The additional surveillance is a more restrictive change, ensures the trip functions remain operable and is, therefore, acceptable.

9. Existing TS 3.6.4.1 requires two independent, operable, containment hydrogen (H_2) monitors when the reactor is critical. Improved TS Table 3.3.3-1, Functional Unit 11, also specifies requirements for two H_2 monitors. The applicability for the H_2 monitors now includes Modes 1, 2, and 3, because these instruments relate to the diagnosis and pre-planned actions required to mitigate applicable design-basis accidents assumed to occur in these Modes. The change is consistent with NUREG-1431. This additional mode-related requirement is acceptable.

10. The existing TS refer only to two interlocks (P-7 and P-8) in LCO 2.3.3 as being the point at which the power range nuclear flux and single RCS loop loss-of-flow trip functions can be blocked. The improved TS include Table 3.3.1-1, Function 15.a, "Intermediate Range Neutron Flux, P-6," set at equal to or greater than 5E-11 ampere; Function 15.b, "Low Power Reactor Trips Block, P-7," set at less than 8.5% RTP, Function 15.c, "Power Range Neutron Flux, P-8," set at less than 50% RTP; Function 15.d, "Power Range Neutron Flux, P-9," set at less than 50% RTP; and Function 15.e, "Power Range Neutron Flux, P-10," set at equal to or greater than 6% RTP. In addition SR 3.3.1.11 verifies that each trip function that can be blocked by an interlock is not blocked in a region in which the trip function is assumed to be operable. The additional instrumentation requirements are more restrictive, and are acceptable.

11. The existing TS setpoint for permissive P-7 was changed from equal to or less than 8.5% RTP to equal to or less than 6% RTP. The setpoint change is acceptable because the improved TS limit is within the existing TS limit.

12. Existing TS Table 3.5-1 Functional Unit 11 was also revised to add requirements for Turbine Trip on Turbine Stop Value Closure. This is an anticipatory trip function but provides a complete listing of those turbine trip functions which result in a reactor trip. The addition of the trip function is acceptable.

13. Existing TS Table 3.5-5 only requires radiation monitors R-11 and R-12 to be operable during shutdown purges. Improved TS LCO 3.3.5 revises this to be Modes 1, 2, 3, and 4, and in Mode 6 when required by LCO 3.9.3, containment penetrations. This change ensures that the gaseous and particulate radiation monitors which actuate containment ventilation isolation are available during those Modes in which the purge valves can be opened. The change is consistent with NUREG 1431. The NRC staff finds this more restrictive change to be acceptable.

14. Existing TS Table 3.5.1, Functional Unit 1, Manual, and associated Action Statement 1, is moved to improved TS, Table 3.3.1-1, Functional Unit 1, Manual Reactor Trip. This action is revised to add requirements for operability of the Manual Reactor Trip function in Modes 3, 4, and 5 when the control rod drive system is capable of rod withdrawal or if all rods are not fully inserted. These actions ensure the plant is placed in a condition in which the trip function is no longer required for the associated modes of operation. The required actions assure the plant is placed in a condition in which the trip function is no longer required for the associated modes of operation. These changes are acceptable because the improved TS requirements encompass the existing TS requirements.

15. Existing TS Table 3.5-4, Functional Unit 4.c, Steam Line Isolation, High Steam Flow Coincident with Low T_{avg} and SI, is moved to the improved TS, Table 3.3.2-1, Functional Unit 4.d, Steam Line Isolation, High Steam Flow Coincident with Safety Injection and Coincident with T_{avg} — Low. The revised setpoint (equal to or less than 0.4E6 lbm/hr @ 755 psig) reflects, and is more conservative than, the value in the accident analyses, RG&E setpoint calculation DA-EE-92-089-21, and is, therefore, acceptable.

16. Existing TS Table 3.5-4, Functional Unit 1.c, "Safety Injection and Feedwater Isolation, Low Pressurizer Pressure," is moved to improved TS, Table 3.3.2-1, Functional Unit 1.d, Safety Injection, Pressurizer Pressure — Low. The existing TS setpoint is equal to or greater than 1723 psig and the setpoint given in the improved TS is equal to or greater than 1750 psig. The revised setpoint reflects the value in the accident analyses, RG&E setpoint calculation DA-EE-92-087-21, and is, therefore, acceptable. Any safety injection start initiates feedwater isolation. The change in the setpoint is more limiting and, therefore, is also acceptable.

17. Existing TS Table 3.5.1, Functional Unit 4, "Nuclear Flux Source Range," requires suspending all operations involving positive reactivity changes if the number of operable channels for the source range neutron flux channels is one less than the minimum number of operable channels required. If the channel is not restored to operable status within 48 hours, the reactor trip breaker is to be opened within the next hour.

    In Modes 3, 4, and 5, only the source range neutron flux provides the required core protection. Consequently, a Mode reduction is necessary in these Modes, if the inoperable channel is not restored. These clarifications and additional restrictions ensure that the plant is removed from the applicable condition, or driven to stable conditions. These additional requirements are acceptable.

18. Existing TS Table 3.5-1, Action Statement 14 for Functional Unit 20, automatic trip logic, including reactor trip breakers is revised in improved TS Required Action T.1 to specify a limit of 2 hours to bypass the reactor trip breaker for surveillance testing (Note 1) and 6 hours to bypass the reactor trip breaker for maintenance on undervoltage or shunt trip mechanisms (Note 2). The existing TS for bypassing during maintenance do not specify a time limit.

The NRC staff reviewed the above more restrictive requirements and concludes that they enhance the improved TS. Therefore, the more restrictive requirements are acceptable.

3.3.3.4 Less Restrictive Requirements

In electing to implement the Section 3.3 specifications of NUREG-1431 the licensee proposed a number of conditions that are less restrictive than those that are allowed by the existing TS. The more significant conditions are as follows:

1. Existing TS 3.12.2 limits the reactor to 90% of reactor thermal power (RTP) if the calibration of the excore detectors is not current. Improved TS, SR 3.3.1.6 must be performed every 92 effective full-power days. This SR requires calibration of the excore neutron flux channels to agree with the incore detector measurements before exceeding 90% RTP following refueling. In addition, the SR imposes the provision that the surveillance can be performed up to 7 days after thermal power is equal to or greater than 50%. This calibration cannot be done with sufficient accuracy at low power levels.

   Improved TS SR 3.0.4 prevents entry into a mode or other specified Applicability condition if a surveillance requirement is not current. Therefore, during initial startup, SR 3.0.4 restricts the plant from exceeding 90% RTP unless SR 3.3.1.6 is current (since this surveillance is required for the overtemperature ΔT trip function). However, if SR 3.3.1.6 is not current when greater than 90% RTP, SR 3.0.3 provides up to 24-hours to perform the necessary surveillance. If SR 3.3.1.6 is not performed within the 24-hour limit, the overtemperature ΔT trip function is declared inoperable, and LCO 3.0.3 is entered, forcing shutdown to Mode 3. As such, there is a maximum 24-hour window in which the plant could be greater than 90% RTP with SR 3.3.1.6 not current.

   It is noted that existing TS 3.12.2 restricts the plant to equal to or less than 90% RTP under these conditions, but there is no Completion Time for remaining at this power level. Because of the short time frame to complete improved TS SR 3.3.1.6 before requiring a plant shutdown, it is acceptable not to add further operator instructions to require a power reduction during this same time period it takes to perform the surveillance.

2. The existing TS 3.5.3.2 requires restoration within 7 days for one inoperable accident monitoring instrumentation channel (for functions with two or more channels). In improved TS 3.3.3, Condition A, "Post-Accident Monitoring Instrumentation," (except for "RCS Hot Leg Temperature and RCS Cold Leg Temperature" the licensee changed this restoration Completion Time to 30 days. The 30-day Completion Time is based on industry operating experience, and accounts for the remaining operable channel, the passive nature of the instrument, and the low probability of an event requiring post-accident monitoring instrumentation during this interval. Further, for the reactor coolant system hot leg and cold leg temperature instrumentation, the improved TS allows 7 days to

restore the inoperable channel. The existing TS 3.5.3.3 requires a restoration time of 48 hours for multiple inoperable accident monitoring instrumentation channels (or inoperable channels and inoperable diverse channels). In improved TS 3.3.3, Condition D the licensee changed this restoration Completion Time to 7 days (except that 72 hours is allowed to restore one of the two hydrogen monitors.).

Because of the passive function of the accident monitoring instrumentation, and the operator's ability to respond to an accident using alternative instruments and methods for monitoring, it is not appropriate to impose stringent out-of-service times. In some instances, the existing allowable outage time for these monitoring instruments is shorter than the allowable outage time for the system needed to maintain the monitored parameter within limits. Further, because of the likelihood that the instrumentation can be repaired in the allowed time, continued operation for the specified Completion Times is supported. Alternate monitoring methods are available while the accident monitoring instrument channel(s) are inoperable. Therefore, these less restrictive changes are acceptable.

3. Existing TS 3.5.3.2 requires a Mode change to hot shutdown within the next 12 hours if an inoperable post-accident monitoring channel has not been restored to operable status. Improved TS 3.3.3, Required Action H.1, requires the initiation, preparation, and submittal of a Special Report for the same condition for the reactor vessel water level and containment area radiation (high range). For other functions, Required Actions G.1 and G.2 require shutdown to Mode 3 within 6 hours, and to Mode 4 within 12 hours consistent with the current requirements.

   The Bases for Required Action H.1 provide the details of what is required within the Special Report and the allowed Completion Time for submittal. Placing this information in the Bases is consistent with NUREG-1431. The Bases also provide justification as to why a Special Report is adequate in lieu of hot shutdown. Because of the passive function of these two functions and the operator's ability to respond to an accident using alternative instruments and monitoring methods, it is not appropriate to require shutdown when these functions are out-of-service. Therefore, this less restrictive change is acceptable.

4. Existing TS 3.6.4.2 requires actions to restore an inoperable Hydrogen (H_2) monitor channel within 30 days. In improved TS 3.3.3, Required Action B.1 action for one channel inoperable for more than 30 days is revised from requiring a plant shutdown to requiring a Special Report.

   The Bases for Required Action B.1 provide details of what is to be included in the Special Report and the allowed Completion Time for that submittal. Placing this information in the Bases is consistent with NUREG-1431. The Bases also provide justification as to why a Special Report is adequate in lieu of hot shutdown. Further, the H_2 concentration within containment is not expected to reach flammability limits until 31 days following an accident. Because of the passive function of these instruments and the operator's ability to respond to an accident using alternative instruments and methods for monitoring, it is not appropriate to impose stringent shutdown requirements for this out-of-service instrumentation.

5. Existing TS 4.4.7.1 requires a daily verification that the H_2 monitors are operable in 'ON' or 'STANDBY.' Existing TS 4.4.7.2 requires a quarterly channel calibration of the H_2 monitors. Improved TS SR 3.3.3.1 requires a channel check of these instrument channels every 31 days while SR 3.3.3.2 requires a channel calibration every 24 months.

   The licensee states the change in channel check frequency from once daily to once every 31 days is based on NUREG-1431, which justifies the frequency on the basis that channel failures are rare. In addition, the H_2 monitors are only used under post-accident conditions to detect high H_2 concentration levels that could potentially lead to a breach of containment. The Bases for LCO 3.6.7 state that the minimum H_2 flammability concentration will not be reached until 31 days following an accident. This provides sufficient time for operators to detect any failure of an H_2 monitor. Such a failure would be readily observed because of the expected H_2 concentration increases following the accident. The H_2 monitors can be repaired in this situation. Also, the licensee can use the post-accident sampling system (if required) for additional H_2 monitoring. This change is consistent with NUREG-1431. Based on the above, this less restrictive requirement is acceptable.

   Improved TS SR 3.3.3.2 requires a channel calibration of these H_2 monitoring channels every 24 months, rather than quarterly as previously required. Currently, RG&E performs two types of calibration on the H_2 monitors. The first type of calibration is performed monthly, and consists of turning the monitors on (since they are normally in standby), and ensuring that the monitors are correctly zeroed and measuring H_2 concentration between 0% to 10%. The monitors are adjusted as necessary to ensure that these two parameters are acceptable. The monitors are then supplied with two known concentrations of H_2 sample gas (5% and 9%), and all locations that indicate H_2 concentrations are then viewed to ensure that the indicated concentrations are within acceptable tolerance limits.

   The second calibration is performed annually, and consists of this same test, except that all connected indicators are also calibrated against acceptable tolerance limits (i.e., "as found" values are

determined during testing). Indicators have a very low rate of drift, and typically support a 24-month calibration interval. Ginna procedure CH-EPIP-CVH2 starts the monitors immediately following an accident. During that startup, the instruments are adjusted with respect to their zero and span readings. Time is allowed for these actions since, as stated, in the Bases for LCO 3.6.7, the minimum H_2 flammability concentration within containment would not be reached until 31 days following an accident.

Thus, with this H_2 monitor startup calibration, the H_2 monitors support a surveillance interval of 24 months. A review of the monthly calibrations for the H_2 monitors shows a failure (that is, out-of-tolerance) rate of less than 3%. Even with a failure of an H_2 monitor, it is likely that the redundant H_2 monitors will remain within operational limits. With this low overall failure rate, the extension of the calibration frequency to 24 months is acceptable.

6. Existing TS Table 3.5.1, Functional Unit 18, "Loss of Voltage 480-Vac Safeguards Bus," and Functional Unit 19, "Degraded Voltage 480-Vac Safeguards Bus," requires two channels of the loss of voltage function and two channels of degraded voltage function per bus. By contrast, improved TS 3.3.4 requires two operable loss-of-power diesel generator start channels per bus.

   The loss-of-power diesel generator start logic for each diesel generator is comprised of a two-out-of-two output logic. Each of the two sub-channels input to the output logic consists of one degraded voltage channel and one loss-of-voltage channel, each monitoring its associated 480-Vac safeguards bus, and configured in a one-out-of-two logic. Either or both relays (degraded voltage and loss-of-voltage) from both subchannels must actuate in order to generate an undervoltage signal on the bus to start the diesel generator. RG&E added a descriptive drawing to the Bases for LCO 3.3.4, with additional supporting Bases text. However, because of the system design, if either the degraded voltage or the loss-of-voltage function is inoperable, the entire undervoltage channel must be tripped. That is, both the degraded voltage and loss-of-voltage functions are tripped for that subchannel, allowing either condition observed by the other subchannel to start the diesel generator.) This makes the actuation logic become one-out-of-one, until the inoperable channel is restored. This change provides greater clarity to the operators without reducing the system requirements, and is acceptable.

7. In existing TS Table 3.5-1, Action Statement 14, the restoration time for the automatic trip logic and reactor trip breakers is revised from requiring a shutdown in 6 hours to provide 48 hours to restore the reactor trip breakers, the undervoltage and shunt trip mechanisms, and the automatic trip logic channels to operable status in Modes 3, 4, and 5 before initiating action to fully insert all control rods (improved TS 3.3.1, Required Action W.1).

The licensee also revised the actions to allow 6 hours to restore an automatic trip logic channel to operable status in Modes 1 and 2 before initiating a plant shutdown to Mode 3 (improved TS 3.3.1, Required Actions R.1 and V.1). In addition, the licensee revised the actions to allow 1 hour to restore the reactor trip breaker to operable status in Modes 1 and 2 before initiating a plant shutdown to Mode 3 (improved TS 3.3.1, Required Action S.1 and U.1).

The restoration times of 48 hours and 1 hour, are reasonable considering that the remaining operable channel and reactor trip breaker is adequate to perform the safety function and given the low probability of an event during this interval. Further, the existing TS allow 48 hours to restore the undervoltage or shunt trip mechanisms (what trips the reactor trip breakers). Thus, the restoration times are in line with the current requirements, and are acceptable. The 6-hour restoration time is acceptable and this change is addressed as part of the WCAP-10271 evaluation in Section IV of this report.

8. The licensee revised existing TS Table 3.5-1, Action Statement 2, for Functional Unit 2, "Neutron Flux Power Range" (low setting and high P setting); Unit 5, "Overtemperature ΔT;" Unit 6, "Overpower ΔT;" and Unit 7, "Low Pressurizer Pressure." Specifically, this revision allows an inoperable channel to be placed in the tripped condition within 6 hours in Required Actions D and G of the improved TS (rather than 1 hour). The licensee also revised this action with a Note to Required Action D allowing an inoperable channel to be bypassed for up to 4 hours (rather than 2 hours) during surveillance testing of a redundant channel. These changes in the Completion Times are addressed in Section 4.0 of this SE.

9. Existing TS Table 3.5-1, Action Statement 5, for Functional Unit 8, "Hi Pressurizer Pressure", Unit 9, "Pressurizer — Hi Water Level;" and Unit 13, "Low Steam Generator Water Level" allows the plant to continue operation until the next functional test of an operable channel, provided that the inoperable channel is placed in the tripped condition within 1 hour. Improved TS 3.3.1, Condition D, allows 6 hours (rather than 1 hour) to place the channel in trip for the same condition for these functional units (Improved TS Table 3.3.1-1, Functional Units 7.b, 8, and 13, respectively). This action replaces the current limitation that is tied to the next functional test of an operable channel. A Note allows bypassing an inoperable channel for up to 4 hours in order to perform surveillance testing of other channels.

The current requirement limits the ability to perform channel functional tests on operable channels for functional units with two-out-of-three logic. Providing the Note to bypass the inoperable channel gives operators adequate time to perform required surveillance testing in a safe and orderly manner. These

changes in the Completion Times are addressed in the Section IV of this report.

10. Existing TS Table 3.5-1, Action Statements 2 and 6, for Functional Unit 7, "Low Pressurizer Pressure;" Unit 10, "Low Flow in Both Loops;" and Unit 14, "Undervoltage 4 kV Bus," allow plant operation to proceed with an inoperable channel, provided that the inoperable channel is placed in the tripped condition within 1 hour. Improved TS 3.3.1, Condition K, allows 6 hours (rather than 1 hour) to place the channel in trip for the same condition for these functional units (Improved TS, Table 3.3.1-1, Functional Units 7.a, 9.b, and 11.a, respectively) and for new Functional Unit 10.b, Reactor Coolant Pump (RCP) Breaker Position — Two Loops.

    This action replaces the current limitation that is tied to the next functional test of an operable channel. A Note allows bypassing an inoperable channel for up to 4 hours in order to perform surveillance testing of other channels.

    The current requirement limits the ability to perform functional tests on operable channels for functional units with two-out-of-three logic. Providing a Note to bypass the inoperable channel gives operators sufficient time to perform required surveillance testing in a safe and orderly manner. These changes in Completion Times are addressed in Section 4.0 of this report.

11. Existing TS Table 3.5-1, Action Statement 5, for Functional Unit 10, "Low Flow in One Loop", allows operation to proceed with an inoperable channel, provided that the inoperable channel is placed in the tripped condition within 1 hour. Improved TS 3.3.1, Condition M, allows 6 hours (rather than 1 hour) to place the channel in trip for the same condition for this functional unit (Improved TS, Table 3.3.1-1, Functional Unit 9.a).

    This action replaces the current limitation that is tied to the next functional test of an operable channel. A Note allows bypassing an inoperable channel for up to 4 hours in order to perform surveillance testing of other channels. The current requirement limits the ability to perform channel functional tests on operable channels for functional units with two-out-of-three logic. Providing a Note to bypass the inoperable channel gives operators sufficient time to perform required surveillance testing in a safe and orderly manner. These changes in Completion Times are addressed in Section 4.0 of this report.

12. Existing TS Table 3.5-1, Action Statement 5, for Functional Unit 11, "Turbine Trip," allows operation to proceed with an inoperable channel provided that the inoperable channel is placed in the tripped condition within 1 hour. Improved TS 3.3.1, Condition P, allows 6 hours (rather than 1 hour) to place the channel in trip

for the same condition for this functional unit (Improved TS, Table 3.3.1-1, Functional Units 14.a and 14.b).

This action replaces the current limitation that is tied to the next functional test of an operable channel. A Note allows bypassing an inoperable channel for up to 4 hours in order to perform surveillance testing of other channels. The current requirement limits the ability to perform functional tests on operable channels for functional units with two-out-of-three logic. Providing a Note to bypass the inoperable channel gives operators sufficient time to perform required surveillance testing in a safe and orderly manner. These changes in Completion Times are addressed in Section 4.0 of this report.

13. Existing TS Table 3.5-1, Action Statement 7, for Functional Unit 18, "Loss of Voltage 480-Vac Safeguards Bus"; and Unit 19, "Degraded voltage 480-Vac Safeguards Bus," allows operation to proceed with an inoperable channel, provided that the inoperable channel is placed in the tripped condition within 1 hour.

Each required channel actually comprises four relays (two degraded voltage relays and two loss of voltage relays, one of each in each of two sub-channels). One relay from each sub-channel (two-out-of-two logic) must actuate in order to generate an undervoltage signal for the bus. Improved TS 3.3.4, Condition A, allows 6 hours (rather than 1 hour) to place the channel ([sub-channel] comprised of a degraded voltage relay and a loss-of-voltage relay) in trip for the same condition for this functional unit. This action replaces the current limitation that is tied to the next functional test of an operable channel, and replaces the current shutdown actions with a requirement to restore an inoperable channel to an operable status or to enter the applicable conditions for an inoperable diesel generator. A Note allows delaying entry into the required actions for up to 4 hours in order to perform surveillance testing of one channel, provided that the second channel is capable of starting the diesel generator (one-out-of-one logic). Providing a Note allowing 4 hours to perform required surveillance gives operators sufficient time to perform the surveillance testing in a safe and orderly manner. This makes the shutdown requirements on inoperable 480-Vac loss or degraded relays the same as loss of a diesel generator (improved TS 3.8.1 and 3.8.2, which provide adequate compensatory actions to ensure plant safety).

Entering diesel generator actions during testing is not necessary because the Completion Time for an inoperable diesel generator is much greater than the time allowed to perform the surveillance requirement (7 days versus 4 hours). The Surveillance Requirement Note time (4 hours) takes into account the redundancy of the trip channels and the low probability of an event requiring a loss-of-power start occurring during this interval. The loss of the minimum required loss of voltage or degraded voltage channels (one bus) should result in actions that are no more restrictive than actions for the loss of one diesel generator. Therefore, this less restrictive change is acceptable.

14. Existing TS Table 3.5-2, Action Statement 11, for Functional Unit 2.b, "Hi-Hi Containment Pressure," for initiation of containment spray, allows operation to proceed with an inoperable channel, provided that the inoperable channel is placed in the tripped condition within 2 hours. Improved TS 3.3.2, Condition J, allows 6 hours (rather than 2 hours) to place the channel in trip for the same condition for this functional unit (Improved TS, Table 3.3.2-1, Functional Unit 2.c).

    This action replaces the current limitation that is tied to the next functional test of an operable channel. A Note allows bypassing an inoperable channel for up to 4 hours in order to perform surveillance testing of other channels, provided that the function maintains initiation capacity. The current requirement limits the ability to perform functional tests on operable channels for functional units with two-out-of-three logic. Providing a Note to bypass the inoperable channel gives operators sufficient time to perform required surveillance testing in a safe and orderly manner. These changes in the Completion Times are addressed in Section 4.0 of this report.

15. Existing TS Table 3.5-2, Action Statement 12, for Functional Unit 3.b.ii, "Steam Generator Water Level Low—Low Start of Turbine-Driven Pump", Unit 5.a, "Hi-Hi Steam Flow with Safety Injection" (steamline isolation); Unit 5.b, "Hi Steam Flow and 2-of-4 Low T_{avg} with Safety Injection" (steamline isolation), allows operation to proceed with an inoperable channel provided that the inoperable channel is placed in the tripped condition within 1 hour. Improved TS 3.3.2, Condition F, allows 6 hours (rather than 1 hour) to place the channel in trip for the same condition for these functional units (Improved TS, Table 3.3.2-1, Functional Units 6.b, 6.d, 4.e, and 4.d, respectively).

    This action replaces the current limitation that is tied to the next functional test of an operable channel. A Note allows bypassing an inoperable channel for up to 4 hours in order to perform surveillance testing of other channels. The current requirement limits the ability to perform functional tests on operable channels for functional units with two-out-of-three logic. Providing a Note to bypass the inoperable channel gives operators sufficient time to perform required surveillance testing in a safe and orderly manner. These changes in Completion Times are addressed in Section 4.0 of this report.

16. Existing TS Table 3.5-2, Action Statement 12, for Functional Unit 3.c, "Loss of 4-kV Voltage Start Turbine Driven Pump" (auxiliary feedwater), and Action Statement 6 for Functional Unit 6.e, Trip of

Both Feedwater Pumps Starts Reactor Driven Pumps allows operation to proceed with an inoperable channel, provided that the inoperable channel is placed in the tripped condition within 1 hour. Improved TS 3.3.2, Conditions D and G, allow 48 hours (rather than 1 hour) to restore the channel before requiring a Mode change.

This action replaces the current limitation that is tied to the next functional test of an operable channel. These changes in Completion Times are addressed in Section 4.0 of this report.

17. Existing TS Table 3.5-2, Action Statement 9, for Functional Unit 1.b, "High Containment Pressure" (safety injection); Unit 1.c, "Steam Generator Low Steam Pressure/Loop" (safety injection); Unit 1.d, "Pressurizer Low Pressure" (safety injection); Unit 3.b.i, "Steam Generator Water Level Low-Low, Start Motor-Driven Pumps" (auxiliary feedwater); Unit 5.c, "Hi-Hi Containment Pressure" (steamline isolation); and Unit 6.b, "Hi Steam Generator Level" (feedwater line isolation), allows operation to proceed with an inoperable channel, provided that the inoperable channel is placed in the tripped condition within 1 hour. Improved TS 3.3.2, Conditions F and L, allow 6 hours (rather than 1 hour) to restore the channel for the same condition for these functional units (Improved TS, Table 3.3.2-1, Functional Units 1.c, 1.e, 1.d, 6.c, 4.c, and 5.b, respectively).

    These actions replace the current limitation that is tied to the next functional test of an operable channel. A Note for each condition allows bypassing an inoperable channel for up to 4 hours in order to perform surveillance testing of other channels. The current requirement limits the ability to perform functional tests on operable channels for functional units with two-out-of-three logic. Providing a Note to bypass the inoperable channel gives operators sufficient time to perform required surveillance testing in a safe and orderly manner. These changes in Completion Times are addressed in Section 4.0 of this report.

18. Existing TS Table 4.1-1 specifies the minimum required frequencies for channel checks, calibrations, and operational tests of the reactor trip system and ESFAS instrumentation. Typical calibrations are specified for a 18-month refueling interval. Typical operational tests are specified monthly. Improved TS Tables 3.3.1-1 and 3.3.2-1 provide calibration and test intervals consistent with NUREG-1431 and WCAP 10271-P-A. Those result in a 24-month interval between calibrations, and a 92-day interval for channel operational tests for reactor trip system instrumentation. There are no channel operational tests specified in the improved TS for ESFAS instrumentation. These changes in the SR intervals are addressed in Section 4.0 of this report.

19. Existing TS Table 4.1-1, Functional Unit 11, "Steam Generator Level," specifies a monthly channel operational test and a

calibration every refueling outage. Improved TS Table 3.3.2-1, Functional Unit 5.b, "Steam Generator Level — High," specifies a channel operational test every 92 days and a calibration every 24 months. Improved TS Table 3.3.2-1, Functional Unit 6.b, "Steam Generator Level — Low," specifies a operational test every 92 days and a calibration every 24 months. Improved TS Table 3.3.3-1, Functional Unit 21, "SG Water Level (Narrow Range) to SG A," and Functional Unit 22, "SG Water Level (Narrow Range) to SG B," specify a calibration every 24 months. Improved TS Table 3.3.3-1, Functional Unit 23, "SG Water Level (Wide Range) to SG A," and Functional Unit 24, "SG Water Level (Wide Range) to SG B," specify a calibration every 24 months. These changes in the SR intervals are addressed in Section 4.0 of this report.

20. Existing TS Table 4.1-1, Functional Unit 17, "Reactor Containment Pressure," specifies a monthly channel operational test for the isolation valve signal and a calibration every refueling outage. Improved TS Table 3.3.2-1, Functional Unit 1.c, "Containment Pressure — High," safety injection, specifies a channel operational test every 92 days and a calibration every 24 months. Improved TS Table 3.3.2-1, Functional Unit 2.c, "Containment Pressure — High," containment spray, specifies a channel operational test every 92 days and a calibration every 24 months. Improved TS Table 3.3.2-1, Functional Unit 4.c, "Containment Pressure — High," steamline isolation, specifies a channel operational test every 92 days and a calibration every 24 months. These changes in the SR intervals are addressed in Section 4.0 of this report.

21. Existing TS Table 4.1-1, Functional Unit 2, "Nuclear Intermediate Range," specifies a monthly channel operational test and a calibration every refueling outage. Improved TS Table 3.3.1-1, Functional Unit 3, "Intermediate Range Neutron Flux," specifies a channel operational test every 92 days and a calibration every 24 months. These changes in the SR intervals are addressed in Section 4.0 of this report.

22. Existing TS Table 4.1-1, Functional Unit 26, "Steam Generator Pressure," specifies a monthly channel operational test and a calibration every refueling outage. Improved TS Table 3.3.2-1, Functional Unit 1.e, "Steam line Pressure — Low, safety injection, specifies a channel operational test every 92 days and a calibration every 24 months. These changes in the SR intervals are addressed in Section 4.0 of this report.

23. Existing TS Table 4.1-1, Functional Unit 32, "Steam Flow," specifies a monthly channel operational test and a calibration every refueling outage. Existing TS Table 4.1-1, Functional Unit 33, "T_{avg}," specifies a monthly channel operational test and a calibration every refueling outage. Improved TS Table 3.3.2-1, Functional Unit 4.d, "High Steam Flow Coincident with Safety Injection and Coincident with T_{avg} — Low," steamline isolation,

specifies a channel operational test every 92 days and a calibration every 24 months. These changes in the SR intervals are addressed in Section 4.0 of this report.

24. Existing TS Table 4.1-1, Functional Unit 36, "Radiation Detectors, Control Room Intake," specifies a monthly channel operational test and a calibration every refueling outage. Improved TS SR 3.3.5.1 specifies a channel operational test for the control room emergency air treatment system, "Control Room Air Intake Monitors," every 92 days and a calibration every 24 months. These changes in the SR intervals are addressed in Section 4.0 of this report.

25. Existing TS Table 4.1-1, Functional Unit 4, "Reactor Coolant Temperature," specifies a monthly channel operational test and a calibration every refueling outage for the "Overtemperature ΔT" and the "Overpower ΔT" instrumentation. Improved TS Table 3.3.1-1, Functional Unit 5, "Overtemperature ΔT," specifies a channel operational test every 92 days (SR 3.3.1.7) and a calibration every 24 months (SR 3.3.1.10). Improved TS Table 3.3.1-1, Functional Unit 6, "Overpower ΔT," specifies a channel operational test every 92 days (SR 3.3.1.7) and a calibration every 24 months (SR 3.3.1.10). These changes in the SR intervals are addressed in Section 4.0 of this report.

26. Existing TS Table 4.1-1, Functional Unit 40, "Manual Trip Reactor," specifies a operability test every refueling outage. Improved TS Table 3.3.1-1, Functional Unit 1, "Manual Reactor Trip," specifies a trip actuation device operational test every 24 months (SR 3.3.1.11). This change in the SR interval is addressed in Section 4.0 of this report.

27. Existing TS Table 4.1-1, Functional Unit 5, "Reactor Coolant Flow," specifies a monthly channel operational test and a calibration every refueling outage. Improved TS Table 3.3.1-1, Functional Unit 9.a, "Reactor Coolant Flow — Low, Single Loop," and Functional Unit 9.a, "Reactor Coolant Flow — Low, Two Loops," specify a channel operational test every 92 days (SR 3.3.1.7) and a calibration every 24 months (SR 3.3.1.10). These changes in the SR intervals are addressed in Section 4.0 of this report.

28. Existing TS Table 4.1-1, Functional Unit 6, "Pressurizer Water Level," specifies a monthly channel operational test and a calibration every refueling outage. Improved TS Table 3.3.1-1, Functional Unit 8, "Pressurizer Water Level — High, specifies a channel operational test every 92 days (SR 3.3.1.7) and a calibration every 24 months (SR 3.3.1.10). These changes in the SR intervals are addressed in Section 4.0 of this report.

29. Existing TS Table 4.1-1, Functional Unit 7, "Pressurizer Pressure," specifies a monthly channel operational test and a calibration every refueling outage. Improved TS Table 3.3.1-1, Functional Unit

7.a, Pressurizer Pressure — High, and Functional Unit 7.b, "Pressurizer Pressure — Low, specify a channel operational test every 92 days (SR 3.3.1.7) and a calibration every 24 months (SR 3.3.1.10). Improved TS Table 3.3.2-1, Functional Unit 1.d, "Pressurizer Pressure — Low," specifies a channel operational test every 92 days (SR 3.3.2.2) and a calibration every 24 months (SR 3.3.2.5). These changes in the SR interval are addressed in Section 4.0 of this report:

30. Existing TS Table 4.1-1, Functional Unit 8, "4-kV Voltage and Frequency," specifies a monthly channel operational test and a calibration every refueling outage. Improved TS Table 3.3.1-1, Functional Unit 11.a, "Undervoltage, Buses 11A and 11B," and Functional Unit 11.b, "Underfrequency, Buses 11A and 11B," specify a trip actuation device operational test every 92 days (SR 3.3.1.9) and a calibration every 24 months (SR 3.3.1.10). Improved TS Table 3.3.2-1, Functional Unit 6.d, "Undervoltage, Bus 11A and 11B (Turbine Driven Pumps Only)," specify a trip actuation device operational test every 92 days (SR 3.3.2.3) and a calibration every 24 months (SR 3.3.2.5). These changes in the SR intervals are addressed in Section 4.0 of this report.

31. Existing TS Table 3.5.1, Functional Unit 2.b, "Neutron Flux Power Range High Setting," allows operation to proceed with an inoperable channel provided that the channel is placed in 'TRIP' within 1 hour and the requirements for the minimum number of channels is satisfied. This action is revised to add Required Actions D and F of improved TS LCO 3.3.1 to place the channel in trip within 6 hours, and in Mode 3 within the following 6 hours if not completed.

    Placing the inoperable channel in trip allows the reactor trip system to function should an additional channel trip. Reducing the power level removes the plant from the applicability of the neutron flux power range instruments. This change is consistent with NUREG-1431 and the accident analysis assumptions, therefore, this less restrictive change is acceptable.

32. Existing TS Table 3.5-2 Function 4.2.a, "Manual Containment Ventilation Isolation (CVI)" was not added to the improved TS. The actual manual initiation of CVI is accomplished via manual containment spray actuation (Function 4.2.c and improved TS LCO 3.3.5, Table 3.3.5-1). There is no actual manual CVI pushbutton available to operations. This change is acceptable since the manual initiation function is being retained in technical specifications.

33. Existing TS Table 3.5-2 Functional Unit 4.2.b and Table 3.5-5, Action P were revised in improved LCO 3.3.5 to allow 4 hours to isolate a purge flow path with an inoperable containment ventilation isolation radiation monitor. Existing TS Table 3.5-2

does not provide any Completion Time for this action while Table 3.5-5 allows 1 hour. The 4-hour Completion Time is consistent with the required action for isolating an inoperable containment isolation valve which includes the purge valves. It is also consistent with NUREG-1431. Since there are remaining signals to isolate the purge valves (i.e., a containment isolation signal), this less restrictive change is acceptable.

34. Existing TS Table 3.5-4, Functional Unit 2.a, "Containment Spray, Manual Initiation," is moved to improved TS Table 3.3.2-1, Functional Unit 2.a, "Containment Spray, Manual Initiation." This is further clarified with separate surveillance and conditions for both the right and the left pushbuttons. Existing TS Table 3.5-4, Functional Unit 2.b, "Containment Spray, High—High Containment Pressure," is moved to improved TS Table 3.3.2-1, Functional Unit 2.c, "Containment Spray, Containment Pressure — High." The current allowable value is equal to or less than 30 psig; and is equal to or less than 32.5 psig in the improved TS. The trip setpoint, equal to or less than 28 psig, is the same in both versions of the TS. The allowable value as revised reflects the value in the accident analyses, RG&E setpoint calculation DA-EE-92-041-21, and is, therefore, acceptable.

35. Existing TS Table 3.5-4, Functional Unit 1.b setpoints and allowable values, Safety Injection and Feedwater Isolation, High Containment Pressure, are moved to improved TS, Table 3.3.2-1, Functional Unit 1.c, Safety Injection, Containment Pressure — High. A safety injection signal from any initiator, starts feedwater isolation. The allowable value is equal to or less than 5.0 psig in the existing TS and is equal to or less than 6.0 psig in the improved TS. The trip setpoint is the same in both versions of the TS. However, the allowable value as revised reflects the value in the accident analyses, RG&E calculation DA-EE-92-041-21, and is, therefore, acceptable.

36. Existing TS Table 3.5-4, Functional Unit 1.d, "Safety Injection and Feedwater Isolation, Low Steam Line Pressure," is moved to improved TS Table 3.3.2-1, Functional Unit 1.e, "Safety Injection, Steam Line Pressure — Low." The current Allowable Value is equal to or greater than 500 psig, and the value in the improved TS is equal to or greater than 358 psig. The trip setpoint is the same in both versions of the TS. As revised, the allowable value reflects the value in the accident analyses, RG&E setpoint calculation DA-EE-92-088-21, and is, therefore, acceptable. A safety injection, from any initiator, starts feedwater isolation. This a less restrictive change with the requirements retained in the improved TS, and is, therefore, acceptable.

37. Existing TS 4.1-4, Functional Units 3a and 3b are revised in improved TS SR 3.3.5.4.to require that the functional test of the valves actuated by containment radiation monitors R-11 and R-12 be

performed once every 24 months versus quarterly. These monitoring channels are inputs to the containment ventilation isolation; however, analyses by the licensee have not assumed that these isolation functions will isolate containment for all credible events. This test is a check of the Manual Actuation functions ability to actuate the end device, (i.e., pump starts, valves cycle, etc.). The 24-month test frequency has been shown to be acceptable through operating experience. The NRC staff acceptance of the 24-month test interval is further discussed in Section 4.0 of this evaluation.

38. Existing TS Table 3.5-4, Functional Unit 2.a, "Containment Spray, Manual Initiation," is moved to improved TS Table 3.3.2-1, Functional Unit 2.a, "Containment Spray, Manual Initiation." This is further clarified with separate surveillance requirements and conditions for both the right and left push-buttons. The presentation of these requirements is an administrative change with the requirements retained (and clarified) in the improved TS. The change is, therefore, acceptable.

39. Existing TS 4.8.10 requires AFW pump and valve response time surveillance (once every 18 months) to verify that the train response time is less than 10 minutes. This requirement is not incorporated in the improved TS, but is described in the new Bases. While some accidents do not require AFW for 10 minutes, the small—break LOCA and loss-of-feedwater transients require AFW within much shorter time frames. Therefore, this surveillance does not verify useful information. The operability of the AFW trip actuating device is tested by improved TS SR 3.3.2.7, in accordance with approved plant procedures. This change is consistent with NUREG-1431. Therefore, based on the above, this change is acceptable.

40. Existing TS 3.5.6.2 requires isolating the control room air intake if one detection system is not returned to operable status within 1 hour. Improved TS 3.3.5, Condition A, allows more than one channel of one or more functions to be inoperable, with an action to isolate the control room in 1 hour if not restored by that time. Condition A of LCO 3.3.5 only allows 1 hour to restore an inoperable channel consistent with existing TS 3.5.6.2. Even with a loss of function of the automatic actuation logic; (i.e., all three radiation monitors inoperable) the control room emergency air treatment system (CREATS) is still capable of performing its safety function and being manually isolated within 1 hour. The probability of an accident within this 1 hour is very small. This change is consistent with NUREG-1431, and retains the current restoration time. Therefore, this change in the number and type of channels allowed to be inoperable is acceptable.

41. If the number of operable channels for the intermediate range neutron flux channels is one less than the minimum number of

operable channels required, existing TS Table 3.5.1, Functional Unit 3, requires that all operations involving positive reactivity changes be suspended, and all rod cluster control assembly must be fully inserted within 6 hours.

Improved TS Table 3.3.1-1, Functional Unit 3, "Intermediate Range Neutron Flux," invokes Conditions E and F. If one channel is operable and the thermal power is not less than 5E-11 amperes, Required Action E requires a reduction in thermal power to less than 5E-11 amperes or an increase in +thermal power to equal to or greater than 8% RTP (enabling monitoring reactor power with the power range instruments). If Required Action E.1 or E.2 are not completed within 2 hours, Condition F requires Mode 3 within the following 6 hours, thus limiting the time of operating with a single inoperable intermediate channel. Permissive P-6 is covered by Function 15.a of the same table. The intermediate range neutron flux channels must be operable when the power level is above the capability of the source range and below the capability of the power range. The associated required actions ensure that the plant is no longer in the applicable condition. Specifically, these actions involve controlled power adjustments, and take into account the low probability of an event during the period that may require protection of the intermediate range neutron flux trip. These additional actions requiring power level changes to remove the applicability of the condition, are acceptable as more restrictive requirements.

42. If the number of operable channels for the source range neutron flux channels is one less than the minimum number of operable channels required, existing TS Table 3.5.1, Functional Unit 4, "Nuclear Flux Source Range," requires suspending all operations involving positive reactivity changes. In addition, if the channel is not restored to operable status within 48 hours, the reactor trip breaker is to be opened within the next hour.

    Improved TS Table 3.3.1-1, Functional Unit 4, identifies the action statements for inoperable source range neutron flux instrumentation. Specifically, the reactor trip breakers and the reactor trip bypass breakers are to be opened, immediately upon discovery of two inoperable channels when in Mode 2 at less than 6% thermal power with neither intermediate range channel on scale (Condition G).

43. Existing TS Table 3.5-1, Action Statement 14 for Functional Unit 20, concerns automatic trip logic, including reactor trip breakers. Specifically, this Statement requires that "if one of the diverse reactor trip breaker trip features (undervoltage or shunt trip attachment) on one breaker is inoperable, restore it to operable status within 48 hours or declare the breaker inoperable." If one trip feature is inoperable at the end of the 48-hour period, it must be repaired, or the plant must not be in an operating mode,

and the reactor trip breaker must be open, following an additional 6-hour time period." This action is revised in the improved TS.

Within 1 hour of discovering two inoperable trip mechanisms (shunt or undervoltage) when in Modes 1 or 2, at least one trip mechanism must be restored to operable status (Required Action U.1). The 1-hour Completion Time is acceptable due to the low probability of an event and the redundancy provided by the remaining two diverse trip mechanisms. Within 48 hours of a trip mechanism being inoperable when in Modes 1 or 2, the trip mechanism must be restored to operable status (required Action U.2). If Required Action U.1 or U.2 cannot be accomplished within the required Completion Time, Required Action U.2 requires the plant be in Mode 3 within the next 6 hours.

Condition W applies for Modes 3, 4, and 5, when the control rod drive system is capable of rod withdrawal, or if all control rods are not fully inserted. Condition W remains 1 hour following the discovery of two inoperable reactor trip breakers (including any reactor trip bypass breakers that are racked in and closed to bypass a reactor trip breaker), two inoperable reactor trip mechanisms (shunt or undervoltage trips), or two automatic trip logic trains. In Condition W, one of the inoperable breakers, trip mechanisms, or logic trains, must be restored within 48 hours. If Required Action W.2 cannot be completed in the allotted time Required Action X.1 requires immediate action to fully insert all control rods, and Required Action X.2 allows 1 hour to disable the control rod drive system so that it is incapable of withdrawing rods. Therefore, no power increase is allowed, but the reactor trip breakers are allowed to remain closed.

The restoration time of 48 hours for Required Actions U.2 and W.2 is reasonable considering the remaining operable breaker is adequate to perform the safety function and given the low probability of an event during this interval. The 1 hour provided by Required Actions T.1, W.1, and X.2 gives sufficient time to accomplish the action in an orderly manner.

The less restrictive requirements are acceptable, because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with current licensing practices, operating experience, and plant accident and transient analyses. They give reasonable assurance that the public health and safety will be protected.

3.3.4 Reactor Coolant System

3.3.4.1 Significant Administrative Changes

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed administrative changes to bring the existing TS into

conformance with NUREG-1431 improved TS. The more significant changes resulting from the administrative items are as follows:

1. Existing TS 3.1.1.1 includes the requirements of TS 3.1.1.1.e that specify the operability requirements for coolant loops at temperatures below 350°F. This TS contains a Note associated with the power sources for the RHR loops that has been moved to the electrical power system specification requirements during Modes 5 and 6 operation (LCOs 3.8.2, 3.8.5, 3.8.8, and 3.8.10). This Note permits either the preferred or the emergency power source for RHR loops A and B to be inoperable while in cold shutdown. The requirements are retained in a different specification; therefore, the change is acceptable.

2. Existing TS 3.1.1.1 includes the requirements of TS 3.1.1.1.i and TS 3.1.1.1.j that specify requirements for pump operation to ensure adequate flow for boron mixing during boron additions and during boron dilutions. Without proper mixing, unexpected reactivity increases and accompanying power excursions could result. The improved TS ensure that the appropriate RCS or RHR loop will provide sufficient forced flow (pump operation) for decay heat removal and boron mixing for all operating modes in LCOs 3.4.4, 3.4.5, 3.4.6, 3.4.7, and 3.4.8. The improved TS also continue to permit the interruption of coolant flow for a limited time during which boron dilutions are prohibited. The licensee proposes to replace the existing TS requirements with equivalent improved TS requirements; therefore, these changes are acceptable to the NRC staff.

3. Existing TS 3.1.1 includes the requirements in TS 3.1.1.3.c for setting safety valve trip setpoints. The valve lift settings are required to be set to within ± 1% following testing; however, the operability tolerances of existing TS 3.1.1.3.c have been revised from 2485 psig ± 1% to 2485 psig + 2.4%, -3% in improved TS 3.4.10, "Pressurizer Safety Valves." The increased operability tolerances have been evaluated in the most limiting pressure transients for Ginna (i.e., loss of external load and locked rotor events) and found to result in acceptable results with respect to the safety limit values. These settings conform to the ASME Code as the code tolerance requirements for relief valves set above 1000 psig are ±1% following the testing and ±3% for operability. This change is a result of an event in which the pressurizer safety valves were found to have drifted outside the existing ±1% tolerance band following testing. The supporting accident analysis shows that revising the safety valve operability setpoint tolerances to those given in LCO 3.4.10 allows sufficient margin to avoid impacting any safety limit. The NRC staff evaluation supporting these revised setpoint tolerances are provided in Section 4.0 of this SE.

These changes are considered purely administrative changes in the statement of requirements in the improved TS and are, therefore, acceptable.

3.3.4.2 Relocated Requirements

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate all or portions of existing TS to licensee-controlled documents as follows:

Existing TS	Title
3.1.1.1	Reactor Coolant Loops
3.1.1.4	Relief Valves
3.1.1.6	Reactor Coolant System Vents
3.1.2	Heatup and Cooldown Limit Curves for Normal Operation
Figure 3.1-1	Ginna Reactor Vessel Heatup Limitations Applicable for the first 21 EFPY using Reg. Guide 1.99, Rev. 2
Figure 3.1-2	Ginna Reactor Vessel Cooldown Limitations Applicable for the first 21 EFPY using Reg. Guide 1.99, Rev. 2
3.1.6	Maximum Reactor Coolant Oxygen, Fluoride and Chloride Concentration
3.3.1	Safety Injection and Residual Heat Removal Systems
3.15	Overpressure Protection System
Table 4.1-2	Minimum Frequencies for Equipment and Sampling Tests
4.3.3	Check Valves
4.3.5	Reactor Coolant Loops

The more significant changes resulting from these relocated items are as follows:

1. Existing TS 3.1.1.1.k contains requirements specified in conditions that prohibit starting an RCP when RCS cold leg temperatures are equal to or less than 330°F. Improved TS LCO 3.4.6, "RCS Loops — Mode 4," and LCO 3.4.7, "RCS Loops — Mode 5, Loops Filled," contain a Note in the LCO Statement to prohibit starting an RCP in Modes 4 and 5 with any RCS cold-leg temperature equal to or less than the low-temperature overpressure protection (LTOP) "enable" temperature specified in the Pressure/Temperature Limits Report (PTLR) unless (1) The secondary-side water temperature of each SG is equal to or less than 50°F above each of the RCS cold-leg temperatures or (2) the pressurizer water volume is less than 324 cubic feet (38% level). Improved TS LCO 3.4.6 and LCO 3.4.7 provide a limit of "equal to or less than the LTOP enable temperature specified in the PTLR" in place of the specific existing temperature limit of equal to or less than 330°F. The PTLR (Specification 5.6.5) includes the existing TS temperature limiting value of equal to or less than 330°F. This change is acceptable since the LTOP limiting value may need to be changed on the basis of the results of surveillance testing of vessel materials. Thus, the improved TS will continue to require the establishment of operational limits that protect the RCS from overpressurization by prohibiting pump operation at low temperatures, the values for which will now be set forth in the

PTLR. This change moves the statement of the acceptable limits to a program referenced in the TSs and is acceptable to the NRC staff.

2. Existing TS 3.15.1 requirements for LTOP of the RCS requires one of two overpressure protection systems to be operable when one or more cold legs is equal to or less than 330°F. This TS also specifies the two PORV setpoints when LTOP operation is required. The improved TS LCO 3.4.12 requires "two PORVs with lift settings specified in the Pressure/Temperature Limits Report (PTLR)". The relocation of the specific settings for the PORV lift setpoint limits to the PTLR is consistent with the guidance in NUREG-1431. The PORV setpoints are periodically updated when the revised pressure/temperature limits conflict with the LTOP analysis limits. The specific RCS pressure and temperature (P/T) and LTOP limits are established in Specification 5.6.6 as previously reviewed and approved in Amendment No. 48. Further, the acceptability of the P/T and LTOP limits are documented in NRC letter, "R. E. Ginna - Acceptance for Referencing of Pressure Limits Report," December 26, 1995. The staff concludes that the PORV setpoints in existing TS 3.15.1 will be retained upon implementation of the improved TS since these setpoints are derived from the RCS P/T and LTOP analysis of Amendment No. 48. Furthermore, changes to these settings will be controlled by the use of approved methodology as set forth in Specification 5.6.6.

3. Existing TS 3.1.6, "Maximum Reactor Coolant Oxygen, Fluoride and Chloride Concentration," and the existing TS Table 4.1-2, "Functional Units 1 and 2," collectively contain all the requirements that relate the chemical concentration limits and sampling of the RCS for oxygen, fluoride, and chloride. These requirements in their entirety were not added to the improved TS but were relocated to the TRM, since these requirements do not fall within the criteria of the Commission's Final Policy Statement. The NRC staff concludes that RCS chemistry is adequately controlled by licensee plant procedures and that sufficient regulatory controls exist since any changes are controlled by 10 CFR 50.59.

4. Existing TS Table 4.1-2, "Functional Unit 7," for the refueling interval calibration of the pressurizer safety valve setpoints is relocated to the IST Program consistent with the format of improved TS SR 3.4.10.1. The IST Program requirements are required by Specification 5.5.7, "Inservice Testing Program." The setpoints and test requirements are unchanged and changes to the calibration frequency will continue to require 10 CFR 50.55a(f). Since this change represents a reorganization of existing TS requirements as program requirements, there is no impact on safe operation of the plant. This change is acceptable to the NRC staff.

5. Existing TS 3.1.1.6, "Reactor Coolant Vents," requires at least one reactor vessel head vent path to be operable during shutdown or critical conditions, and existing TS 4.3.5.6 requires an 18-month

surveillance test of the reactor vessel head vents. Existing TS 3.1.1.6 also contains additional requirements for pressurizer PORVs and their associated block valves which are addressed in existing TS 3.1.1.4. The RCS vent paths are used to exhaust noncondensable gases and steam from the RCS which may inhibit natural circulation following an accident with an extended loss of offsite power. However, these head vents are not in the primary success path of such accidents and are used by operators only if both pressurizer PORVs are unavailable. In addition, these head vents are not relied on to perform a safety function in accident system analyses. Therefore, this requirement was not adopted in improved TS LCO 3.4.11, "Pressurizer Power Operated Relief Valves (PORVs)," since these vents do not fall within the TS criteria specified in the Commission's Final Policy Statement. Specific operability requirements for the vent path are relocated to the TRM; future changes are controlled in accordance with 10 CFR 50.59, and the change is therefore acceptable.

6. Existing TS 3.1.2.1 contains the requirements of TS 3.1.2.1.a, TS 3.1.2.3, and the curves depicted in Figure 3.1-1, and Figure 3.1-2 for determining pressure versus temperature (P/T) limits and limiting temperature rates. The existing TS RCS P/T curves and the RCS heatup and cooldown curve limits were relocated to the PTLR. Requirements for the PTLR are specified in Administrative Control 5.6.6. The NRC staff approved the methodology for developing the P/T curves as specified in the PTLR, and the licensee is required by improved TS 5.6.6 to utilize an NRC-approved methodology. The requirements and actions for RCS temperature and pressure and RCS heatup and cooldown developed according to the PTLR methodology are now in improved TS LCO 3.4.3, "RCS P/T Limits." This LCO is consistent with the guidance of NUREG-1431. The existing TS requirements are relocated to the PTLR for which future changes are controlled in accordance with 10 CFR 50.59. Therefore, this change is acceptable.

7. Existing TS 3.3.1.1.h specifies a 5.0-gpm leakage rate limit for selected pressure isolation check valves and motor-operated isolation valves with RCS temperature above 350°F for the safety injection (SI) and RHR systems. Check valves 877A, 877B, 878F, 878H, and motor-operated isolation valves 878A and 878C are required to be tested as pressure isolation valves (PIVs) by existing Ginna TS 4.3.3.3 which also specifies a 5.0-gpm leakage limit. Improved TS SR 3.4.14.1 and SR 3.4.14.2 for PIVs includes all of these check and motor isolation valve testing requirements found in the existing TS for valves that perform the PIV function. The list of valves is relocated to the Bases for improved TS 3.4.14. Changes to the Bases will be made in accordance with improved TS 5.5.13, "TS Bases Control Program." In addition, the proposed TS are consistent with the guidance of NUREG-1431.

8. Existing TS 3.3.1.7, TS 3.3.1.8, and TS 3.3.1.8.2 modify the LTOP requirement prohibiting two or three SI pumps being operable, to allow the operation of one or more SI pumps if certain requirements are met. This exception was not incorporated into the improved TS LCO 3.4.12 but is relocated to the Bases for LCO 3.4.12 under SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3 together with the details of the TS requirement for how the SI pumps are to be made inoperable. The Bases explain all the acceptable methods and new criteria for ensuring that an SI pump is incapable of injecting into the RCS as assumed in the accident analyses. This change is consistent with the guidance in NUREG-1431 to move the definition of procedural steps or the description of test activities to the Bases. Although only one SI pump is allowed, by improved TS LCO 3.4.12, to be in operation when the PORVs provide the RCS vent path, the limitation of just one operable SI pump is not necessary when the flow path isolation criteria in the Bases are implemented. An example of the new criteria requires closing a valve in the SI pump discharge path and putting the SI pump control switch in "pull stop" position. If each SI pump path has two isolation provisions in effect, it requires two separate actions to remove these isolation provisions before providing an open injection path to the RCS. Thus, regardless of how many SI pumps can operate, the Bases criteria prevent injection flow paths to the RCS. Therefore, the NRC staff finds that operating multiple SI pumps will not pose an overpressurization threat to the RCS with this isolation, since reasonable criteria have been chosen for rendering a pump incapable of coolant injection for LTOP.

These relocated requirements are not required to be in the TS under 10 CFR 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. Further, they do not fall within any of the four criteria in the Commission's Final Policy Statement, as discussed in the Introduction above. The NRC staff concludes that the control of these provisions under 10 CFR 50.59 is acceptable, that the regulatory requirements provide sufficient control of these provisions, and that removing them from the TS is acceptable. Accordingly, the NRC staff concludes that these requirements may be relocated from the TS to the licensee's TS Bases, the PTLR, TRM or the UFSAR, as applicable.

3.3.4.3 More Restrictive Requirements

By electing to implement Section 3.4 of the NUREG-1431 specifications, the licensee proposed a number of conditions that are more restrictive than those required by the existing TS. The more significant conditions are as follows:

1. The action requirements of existing TS 3.1.1.1.b, "Reactor Coolant Loops," specify a one-time check to verify whether the shutdown margin meets the one loop requirements of Figure 3.10-2. If the SDM was within limits, plant operation continued indefinitely with thermal power less than 130 MWt. The improved TS LCO 3.4.5,

Condition A was added for one RCS loop inoperable. One RCS loop is now allowed to be inoperable for 72 hours provided that the shutdown margin as specified in the COLR is checked once per 12 hours and the non-operating RCS loop is operable (i.e., available for natural circulation). This change removes the indefinite time period from the existing TS and now defines time limit for one RCS loop in operation. The NRC staff finds that these new requirements provide reasonable required actions to ensure that adequate flow for heat removal and boron mixing are available while awaiting restoration of both RCS loops to operable status.

2. The action requirements of existing TS 3.1.1.1.d(ii), "Reactor Coolant Loops," suspend all operations involving a reduction in boron concentration in the RCS and immediately initiate corrective action to return a coolant loop to operation when neither RCS loop is in operation. The improved TS LCO 3.4.5 Condition C retains these requirements and adds a new Required Action C.1 to "Deenergize all CRDMs immediately." When all CRDMs are deenergized by opening the reactor trip breakers or de-energizing the MG sets, an inadvertent rod withdrawal is not possible. An inadvertent rod withdrawal during this period could increase the RCS coolant temperature when no RCS loop would be able to convey this heat away to the steam generators. The NRC staff finds that this new requirement further enhances safe conduct of plant operation by preventing this situation from occurring.

3. Existing TS 3.1.1.1.f contains an exception to the requirement that at least one of the coolant loops shall be in operation while the RCS temperature is less than 350°F during steam generator cleaning. The licensee will no longer perform this activity because new SGs are scheduled to be installed during the spring 1996 refueling outage. These steam generators do not have crevices subject to cleaning as described in this TS; therefore, the exception is not needed and is not restated in the improved TS. The change is acceptable to the NRC staff.

4. Existing TS 3.1.1.1.f, "Reactor Coolant Loops," contains the requirement that one RCS or RHR coolant loop must be in operation while the RCS temperature is less than 350°F. The improved TS LCO 3.4.7 and LCO 3.4.8 have added a new LCO requirement that also requires one RHR loop to be operating when in Mode 5 when the RCS temperature is less than 200°F. This change is consistent with the guidance in NUREG-1431. The RHR pump operating requirements are appropriate since an RCP cannot routinely be operated during Mode 5 low-temperature and low-pressure conditions. This change provides for redundant paths for decay heat removal. Therefore, the NRC staff finds that by extending the existing TS requirements for RCS circulation, one RHR coolant loop is always ensured to be in operation, reducing the risk of an accidental boron dilution event.

5. The licensee added a new requirement to the requirements contained in existing TS 3.1.1.1.f. Improved TS LCO 3.4.7 contains an additional alternative requirement for ensuring that sufficient cooling capacity exists during Mode 5 with loops filled. This alternative is an operable SG with a minimum water level of 16%. This option can provide an alternate means of decay heat removal equivalent to an operating RHR loop while in Mode 5 with loops filled. This change provides for redundant paths for decay heat removal. Therefore, the NRC staff finds that by defining an available backup heat removal path, RCS circulation (which contributes significantly to reducing the risk of an accidental boron dilution event) is ensured.

6. Existing TS 3.1.1.1.f, "Reactor Coolant Loops," contains the requirements which permit both RCS and RHR pumps to be removed from service (deenergized) for up to one hour provided that other conditions are met. The improved TS LCO 3.4.8 retained these requirements for all RHR pumps except that the time limit was shortened to 15 minutes when switching from one loop to another. This change was made to this LCO because the loops are not filled due to the reduced coolant inventory. The NRC staff concludes that this increased operational restriction will continue to ensure that sufficient margin exists in the safety analyses of mid-loop events by reducing the time the system is vulnerable during a planned reduced coolant flow.

7. The existing TS 3.1.1.5.b exception for not specifying the pressurizer heater and water level setpoints during RCS hydrostatic testing was not adopted in the new specifications. These tests are performed with RCS temperatures below Mode 3 conditions (i.e., less than 350°F). Since the new specification only requires the pressurizer to be operable in Modes 1, 2, and 3, this exception is no longer required.

8. Existing TS 3.1.1.4.a.i requires inoperable PORVs to be isolated with a block valve for RCS temperatures greater than 350°F. Existing TS 3.1.1.6 requirements are specified during hot shutdown or critical operations as follows: (1) PORV block valves must be closed or capable of being closed if the PORV is capable of being opened, (2) inoperable vent paths must be maintained closed with motive power removed from all valve actuators in the inoperable vent path lines provided at least one vent path is operable. Thirty days are provided to meet these requirements otherwise a controlled reactor shutdown must be initiated, and (3) 72 hours are specified for the repair of inoperable vent paths provided the vent paths are closed with power removed from the valve actuators.

   These requirements were revised in improved TS 3.4.11, "Pressurizer Power Operated Relief Valves (PORVs)," to provide separate required actions based on inoperabilities resulting in degraded PORVs. A PORV is operable if it is capable of being manually controlled.

The improved TS require that a PORV that is inoperable for automatic functions but capable of manual actuation must be isolated by its block valve consistent with existing TS requirements. However, a PORV that is incapable of manual cycling is required to be isolated by its block valve with a Completion Time of 1 hour, and repaired and returned to service with a Completion Time of 72 hours or the plant must initiate a controlled shutdown. With both PORVs inoperable, a controlled shutdown to Mode 3 conditions with RCS less than 500°F must be completed within 8 hours. The operational limit for inoperable PORVs is specified since a steam generator tube rupture (SGTR) event with a loss of offsite power cannot be adequately mitigated without availability of at least one PORV. The 72-hour Completion Time for one inoperable PORV is allowed because a second operable PORV is available.

The licensee revised the block valve requirements to require that one or both inoperable block valves be restored to operable status with a Completion Time of 72 hours or that the plant initiate a controlled shutdown. The operational limit for an inoperable block valve is specified because a stuck-open PORV cannot be isolated if its associated block valve is inoperable. Being unable to isolate a failed open PORV causes a transient that will depressurize the RCS to ambient conditions and that may result in inadequate core cooling.

These changes are consistent with the guidance of NUREG-1431 and they provide more limiting requirements than existing TS; therefore, the changes are acceptable to the NRC staff.

9. Existing TS 3.1.1 contains the requirements of TS 3.1.1.4.a.ii and TS 3.1.1.6 that specify operability requirements for the PORV block valves. These specifications were revised to be more restrictive in improved TS 3.4.11 to require that one inoperable block valve be restored to operable status with a Completion Time of 7 days or that the plant initiate a controlled shutdown. If two block valves are inoperable, one block valve must be restored within 72 hours. The operational limit for an inoperable block valve is specified because a stuck-open PORV cannot be isolated if its associated block valve is inoperable. Being unable to isolate a failed-open PORV results in a transient that will depressurize the RCS to ambient conditions and that could result in inadequate core cooling. The TS completion time allows time to perform most repairs since the block valves are located inside the containment. As discussed above, these changes provide more restrictive operational limits than the corresponding existing TS and are acceptable to the NRC staff.

10. Existing TS 3.1.3.1, "Minimum Conditions for Criticality," states that the minimum temperature for criticality is 500°F. In the improved TS LCO 3.4.2, this temperature is raised to 540°F. This

change actually corrects a discrepancy between the defined operating modes and the minimum temperature for criticality requirement. Existing TS 1.2 defines Hot Shutdown as reactivity equal to or less than -1 delta k/k% and T_{avg} equal to or greater than 540°F. In order to achieve criticality at 500°F, the Hot Shutdown condition would have to be directly bypassed. The temperature of 540°F was selected for the new minimum temperature for criticality on the basis of previous operating experience during startup conditions and its proximity to operating temperatures. Currently, existing TS 1.2 does not specify at which point the reactor goes critical, only that operating temperature is "~ 580°F" and that Hot Shutdown is "equal to or greater than 540°F." Normal operating temperature for Ginna is actually 573.5°F. The temperature at which criticality is typically reached is approximately 545°F; however, allowing for instrument uncertainty, this could actually be as low as 540°F. In addition, Hot Zero Power (HZP) at Ginna is 547°F, which is the temperature assumed in several safety analyses. It is concluded that this 7°F tolerance does not adversely affect any of these safety analyses since the Moderator Temperature Coefficient (MTC) is not significantly affected by small temperature differences. The NRC staff finds that revising the minimum temperature for criticality from 500°F to 540°F is a conservative change since it requires additional RCS heatup before obtaining criticality; it is closer to the operating temperature of 573.5°F; and, it does not adversely affect the HZP safety analyses.

11. Existing TS 3.1.4.1.c limits on secondary coolant activity that are specified for conditions when the reactor is critical or when RCS temperature exceeds 500°F must be complied with in Modes 1, 2, 3, and 4 in improved TS 3.7.14. The secondary coolant activity limit is based on a steamline break and the resulting dose consequences. The RCS temperature limit of greater than 500°F is based on preventing the MSSVs from lifting following a SGTR (i.e., an RCS temperature of greater than 500°F is only applicable to primary system activity limits, not secondary limits). The improved TS requirement that the secondary coolant activity limits be met for all of Mode 4 (i.e., RCS greater than 200°F) is consistent with NUREG-1431 and the current required actions if the limit is exceeded.

12. Existing TS 3.1.5.1, "RCS Leakage Detection Systems," and TS 3.1.5.2, "RCS Leakage Limits," are applicable only when the RCS temperature exceeds 350°F. The improved TS LCO 3.4.13 and LCO 3.4.15 have extended this applicability to include Mode 4 or when the RCS temperature is greater than 200°F. This change puts these operational limits in effect for a longer period of time than the existing TS. The NRC staff finds that this change enhances the safety of operations by extending TS requirements and controls to cover the full period of the RCS being at elevated temperature and pressure.

13. Existing TS 3.15.1, "Overpressure Protection Systems," requires low- temperature overpressure protection (LTOP) of the RCS to be operable when one or more cold legs are equal to or less than 330°F. Improved TS LCO 3.4.12 has added a new Condition C with required actions for the accumulators. The accumulators are required by improved TS to be isolated when their pressure exceeds the maximum RCS pressure permitted for the existing cold leg temperatures as specified in the PTLR. The operator is required to isolate or depressurize the affected accumulator under these conditions. A third alternative is to increase the RCS cold-leg temperature. This action prevents an accumulator from overpressurizing the RCS and causing actuation of the LTOP system. The NRC staff finds that this new requirement prescribes a prudent action to avoid potential inadvertent actuation of the LTOP system and thus enhances the safe conduct of operations at the plant.

14. Existing TS 3.15.1 requires that the low-temperature overpressure protection (LTOP) of the RCS be operable when one or more cold legs are equal to or less than 330°F. During this Applicability, the existing TS 3.15.1.2 allows a 7-day Completion Time to restore one inoperable PORV to operable status while a remaining PORV is operable. If the inoperable PORV cannot be restored, then the plant must depressurize and vent the RCS. Improved TS LCO 3.4.12 defines new Condition B. The requirements of existing TS 3.15.1.2 have been retained in Condition B, but only for Mode 4; whereas, Condition C applies during Modes 5 and 6. Condition C has shortened the allowed outage time to require that the PORV must be restored to operable status with a Completion Time of 72 hours. If the inoperable PORV cannot be restored per Conditions B and C, then the plant must depressurize and vent the RCS per Condition G which is the same as the existing TS. This new limit of 72 hours with one PORV inoperable is reasonable and is consistent with the allowed outage time for one train of ECCS equipment during Modes 1, 2, and 3. These new TS controls and requirements are imposed because of the concern for the consequences from an overpressurization event during Modes 5 and 6. This change will maintain consistent operational requirements throughout the improved TS for low power and shutdown operations.

15. Existing TS 3.15 applicability requirements for the LTOP system include the requirements for one of two overpressure protection systems to be operable with one or more cold legs equal to or less than 330°F. Improved TS LCO 3.4.12 specifies that LTOP is required during Modes 4, 5 and 6: specifically, during Mode 4 when any RCS cold-leg temperature is less than or equal to the LTOP enable temperature specified in the PTLR or when the RHR system is in the RHR mode of operation; during Mode 5 when the RHR system is in the RHR mode of operation; and during Modes 5 and 6 when the reactor vessel head is on and the SG primary system manway and pressurizer manway are closed and secured in position. The change to the existing TS LTOP applicability is the difference between less than

350°F (Mode 4) and the LTOP enable temperature of about 330°F, but the Modes 5 and 6 applicability requirements are consistent with existing TS 3.3.1.7 and TS 3.3.1.8. The equipment requirements are consistent with the current requirements for isolating the SI pumps for all LTOP conditions as follows: when vented with 1.1 square inches, one SI pump is allowed to be operable; when PORVs are LTOP, all three SI pumps must be inoperable with the RCS less than 350°F. This is an improvement in specifying a single LCO for when the LTOP protection is needed and is acceptable to the NRC staff.

16. Existing TS 3.2.5 contains an LTOP-related surveillance requirement to periodically demonstrate that at least one charging pump is not capable of being operated by verifying that the control switch is in the pull-stop position when RCS temperature is greater than 200°F with the RHR in service and that LTOP protection is not operable. Improved TS 3.4.12 Required Action G requires placing the charging pump control in the pull-stop position with a Completion Time of 1 hour when PORVs are inoperable, regardless of the status of the RHR pumps or the mode. This requirement places an additional operational restriction in the form of direct operator guidance to perform an action within a defined time period.

17. Existing TS 3.3.1.1.h and TS 3.3.1.5 requirements for PIV operability to protect against an intersystem LOCA apply when the RCS temperature is equal to or greater than 350.° These requirements are retained in improved TS LCO 3.4.14; however, the Applicability is changed to require PIVs to be operable in Mode 4. Also, when PIVs cannot be restored within the allowed time, the plant must enter Mode 5 within 36 hours to exit the Applicability requirements. This change ensures PIV operability for a longer period of time than the current Ginna TS. The NRC staff finds that this change increases the safety of operation by specifying an action that places the plant in a condition that prevents coolant leakage.

18. Existing TS 3.3.1.5.e permits selected PIVs to be removed from service for up to 12 hours for repair if the in-series motor-operated isolation valve is closed. The existing TS infers that inoperable valves must be isolated immediately. Improved TS LCO 3.4.14, Condition A specifies that a leaking PIV (check valve or motor operated) must be isolated with a Completion Time of 4 hours with a leak-tested valve, and that a second leak-tested valve must be closed within 72 hours. The 4 hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected system if leakage cannot be reduced. This requirement is, in general, a more conservative change since a Completion Time limit is now specified for isolating the leaking valve and the second isolation valve must now be leak tested.

19. Existing TS 4.3, "Reactor Coolant System," contains numerous requirements to verify that the RCS components are operable; however, the improved TS added three new similar SRs. These SR requirements are consistent with the guidance in NUREG-1431. SR 3.4.6.3, SR 3.4.7.3, and SR 3.4.8.2 all require verification of correct breaker alignment for the required but not-in-operation RCP or RHR pump in Modes 4 and 5 every 7 days. The NRC staff finds that these additional TS requirements explicitly verify and ensure that the second pump can be placed in operation if needed to maintain decay heat removal and reactor coolant circulation.

20. The licensee added a new surveillance requirement to verify that the pressurizer heaters in the RCS were operable. The improved TS SR 3.4.9.2 requires verification that the total capacity of the pressurizer heaters is equal to or greater than 100 kW once every 92 days. Demonstrating that the power supplies are capable of producing the minimum power required is an essential change that ensures the reliable operation of the pressurizer heaters as is assumed in the safety analyses.

21. The licensee added a new surveillance requirement to verify that the reactor system components are operable. Improved TS SR 3.4.11.2 requires a complete open/close cycle of each PORV using the nitrogen system once every 24 months at refueling. Demonstrating that the PORVs can be manually actuated is an important change which ensures the PORVs can be used for mitigating SGTR events as assumed in the safety analyses.

22. Existing TS do not contain LCOs for the "RCS Departure From Nucleate Boiling (DNB)" parameters as the guidance document NUREG-1431 suggests. The licensee has agreed to add this new LCO 3.4.1 to the improved TS. This new requirement places limits on pressurizer pressure, RCS T_{avg}, and RCS total flow rate to ensure that the minimum DNBR will be met for all analyzed transients. This LCO is applicable only for Mode 1. If the DNB parameters are not met for 2 hours, then the plant is placed in Mode 2 in 6 hours. The DNB parameters are verified every 12 hours. These additional controls and verifications will ensure that the DNB parameters are maintained within the limits as is currently assumed in the safety analyses.

23. Improved TS 3.4.2, "RCS Minimum Temperature for Criticality," has added two new surveillance requirements (SR 3.4.2.1 and SR 3.4.2.2) which require verification 30 minutes preceding criticality and every 30 minutes that T_{avg} for each RCS loop greater than 540°F when any RCS loop T_{avg} is known to be less than 547°F. These surveillances are intended to ensure that the minimum temperature for criticality is not violated when the reactor is critical with the RCS temperature at less than HZP conditions (i.e., 547°F). A Note to SR 3.4.2.2 specifies that the surveillance is not required to be performed if the low T_{avg} alarm in each loop is reset with a

setpoint greater than 540°F. The NRC staff finds these new requirements allow operators to adjust temperatures or delay criticality so that the LCO limit will not be violated and thus provide assurance that plant operation remains within the bounds of the safety analyses.

24. Improved TS 3.4.3, "RCS Pressure/Temperature Limits," has added a new SR 3.4.3.1 which requires verification every 30 minutes that RCS pressure, temperature, heatup, and cooldown rates are within limits. This surveillance is required only during RCS heatup and cooldown operations, and inservice leak and hydrostatic testing. The 30-minute frequency is sufficient since the heatup and cooldown rates are specified in hourly increments which provides adequate margin to detect and correct minor deviations before exceeding limits. The NRC staff concludes that any time the RCS pressure and temperature are undergoing planned changes, it is prudent to monitor the P/T limits to verify that there have been no challenges to the integrity of the RCS boundary, as provided in this new SR.

25. Improved TS 3.4.1, "RCS Pressure, Temperature, and Flow DNB Limits," has added a new SR 3.4.1.1 which requires verification every 12 hours that pressurizer pressure is within limits during Mode 1. This surveillance is similar to current Ginna TS Table 4.1-1, "Functional Unit 7," which is performed to support reactor trip functions. Since RCS pressure is relatively stable and is frequently scanned by operators, 12 hours is sufficient to detect and correct pressure drift. The NRC staff concludes that this augmented check on the pressurizer pressure ensures that no degradation is beginning and that plant operation is being maintained within the safety analysis assumptions.

26. Improved TS 3.4.1, "RCS Pressure, Temperature, and Flow DNB Limits." has added a new SR 3.4.1.2 which requires verification every 12 hours that RCS average temperature is within limits during Mode 1. Since the RCS temperature is relatively stable and frequently scanned by operators, 12 hours is sufficient to detect and correct temperature drift. The NRC staff concludes that this augmented check on the RCS average temperature ensures that no degradation is beginning and that plant operation is being maintained within the safety analysis assumptions.

27. Improved TS 3.4.1, "RCS Pressure, Temperature, and Flow DNB Limits," contains a new SR 3.4.1.3 that requires verification every 24 months that RCS flow is within limits. This surveillance is required to be performed within 7 days of entering Mode 1 and upon reaching 95% RTP. Even though the flow rate is not expected to vary during steady-state operation, the NRC staff concludes that this initial verification after a refueling outage provides a beneficial comparative assessment of how flow resistance may have changed as a result of core alterations and other refueling activities.

28. Existing TS Table 4.1-4, "Functional Unit 2," requires verification of dose equivalent I-131 once every 14 days when "above 5% RTP." Improved TS 3.4.16 changed this applicability to "when in Modes 1, 2, and in Mode 3 when T_{avg} equal to or greater than 500°F." However, the improved TS SR 3.4.16.2 limits the performance of this surveillance to only during Mode 1 every 14 days and once after changes greater than 15% of RTP within a 1-hour period. Since Mode 1 is defined greater than 5% RTP, the change in surveillance frequency is increased only following a large power change. This change is consistent with the guidance in NUREG-1431. This change places the dose equivalent I-131 limit in effect for a longer period during operational modes and ensures that the reactor coolant specific activity remains within limits. Also, should any RCS leakage occur, this change further minimizes the potential for any resulting offsite dose consequences. The NRC staff concludes that this extension of TS requirements and controls improves the safety of operations at the plant.

29. Existing TS Table 4.1-5, "Functional Unit 3b" requires a channel check surveillance for particulate sampler R-11 once a week. The improved TS SR 3.4.15.1 requires a channel check every 12 hours. This change is required since R-11 is being used to monitor RCS leakage. In the improved TS 3.4.15 under the LCO conditions, R-11 may be the only installed operable system to perform this task for as long as the 30 days allowed when the remaining RCS leakage detection systems are inoperable. The NRC staff finds that this change is prudent given that this is the only radioactive particulate sampler for RCS leakage detection in this condition.

30. Existing TS 4.3.42 contains an exception for testing the PORV block valves when the block valves are closed to isolate a PORV. The TS limits the use of the block valve to those conditions in which the block valve is used to isolate a PORV that is leaking by greater than 10 gpm. In this instance, the block valve is protecting against a potential plant transient which could occur if the block valve were quickly opened. In all other instances, where the block valve is operable and used to isolate a leaking PORV, testing of the block valve is still required on a quarterly basis. The NRC staff finds that this change appropriately limits the exclusion Note for testing of the block valve and is acceptable.

31. Existing TS 3.1.1.1.b, "Reactor Coolant Loops," specifies "an immediate power reduction under administrative control" when the loop operating requirements are not met. Improved TS LCO 3.4.4 changes this requirement to "entry into a Mode 1 condition with thermal power at or less than 8.5% RTP" within 6 hours. The change defines a specific number of hours to reach the specified condition instead of the previous requirement of "immediate" which only defines the starting time, and not the specific time allowed. The NRC staff finds that this specific number of hours to reach this condition clearly tells the operators about the need to achieve an

"immediate" power reduction. The NRC staff finds that this change will augment the safe conduct of operations at Ginna.

32. Existing TS 4.16 requirements for RCS overpressure protection include surveillance requirements for establishing operability of LTOP components to ensure performance of safety functions; however, there are no requirements for verifying accumulator operability. The improved TS LCO 3.4.12 has added two new surveillance requirements (SR 3.4.12.3 and SR 3.4.12.7). SR 3.4.12.3 requires verification once within 12 hours and every 12 hours thereafter, that an accumulator's motor-operated isolation valve is closed, when its pressure is greater than or equal to the pressure allowed by the P/T limit curves in the PTLR. The 12-hour frequency for this SR is typical for slow changing of static parameters and is sufficient considering other indications and alarms available to the operator in the control room. SR 3.4.12.7 requires verification once within 12 hours and every 31 days thereafter, that power to these isolation valves is removed. The 31-day frequency will provide adequate assurance that power is removed since power is removed under administrative controls and the valve position is also verified every 12 hours. The NRC staff finds that these SRs maintain the assumptions of the LTOP safety analysis, ensure that the accumulator does not discharge into the RCS, and thus prevent an overpressure event which could challenge the integrity of the RCS boundary.

The NRC staff reviewed these more restrictive requirements and concludes that they enhance the improved TS. Therefore, the more restrictive requirements are acceptable.

3.3.4.4 Less Restrictive Requirements

In electing to implement Section 3.4 of NUREG-1431 specifications, the licensee proposed a number of conditions that are less restrictive than those that are allowed by the existing TS. The more significant conditions are as follows:

1. Existing TS 3.1.1.1.g specifies requirements for coolant loop operation at an RCS temperature less than 350°F. The action of TS 3.1.1.1.g that requires the plant to be less than 200°F (cold shutdown) within 24 hours was not adopted in improved TS for the condition of both RHR loops inoperable and one RCS loop inoperable. This change is consistent with Condition A of improved TS LCO 3.4.6, RCS Loops — Mode 4. Staying in Mode 4 where RCS loop forced cooling or even natural circulation is available is incrementally safer and is acceptable to the NRC staff since RHR is the only system that provides long-term decay heat removal at temperatures less than 200°F. Thus, the improved TS provide an acceptable alternative to bring the plant to Modes 5 or 6 before an RHR loop is operable.

2. Existing TS 3.1.1.5.a specifies that the lower limit for pressurizer water level is required to be 12% of the pressurizer volume. This lower limit is used in the actuation logic that provides a reactor trip on a safety injection actuation coincident with either low pressurizer level or low pressurizer pressure. The licensee modified the reactor trip logic to eliminate the coincident low pressurizer level trip and permit actuation on a low pressure alone in response to IE Bulletin 79-06A. IE Bulletin 79-06A, acknowledged that because pressurizer water level did not give an indication of the true reactor water level during accident conditions, this input to the logic circuitry should be removed. Therefore, the low pressurizer water level setpoint is not required and was not included in improved TS LCO 3.4.9, "Pressurizer." This change is in accordance with the IE Bulletin, and is acceptable to the NRC staff.

3. Existing TS 3.1.1 contains the requirements of TS 3.1.1.3.a and TS 3.1.1.3.b that specify when safety valves must be operable and in service during cold shutdown and refueling and specify the appropriate remedial actions to take when these limits are not met. These requirements were not included in improved TS LCO 3.4.10, "Pressurizer Safety Valves," since the pressurizer safety valves do not provide overpressure protection during cold shutdown and refueling modes. Technical specification limits for overpressure protection are in the LTOP system requirements specified in improved TS LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System." These requirements ensure that the RCS is maintained less than approximately 500 psig which is well below the pressurizer safety valve setpoint of 2485 psig. Since the pressurizer safety valves do not perform and have not performed the low-temperature overprotection safety function in these lower modes of operation, these safety valve requirements are not adopted in the Ginna improved TS. These changes are consistent with the recommendation of NUREG-1431 and they are acceptable to the NRC staff.

4. Existing TS 3.1.1.2 specifies a 100°F limit across the SG tube sheet. The existing TS requirements are only applicable to operations during Modes 5 or 6 since this is the only time period during which a steam generator can be physically isolated from the RCS heat source with the RCS greater than 200°F. Since there are no RCS isolation valves at Ginna, this scenario is not credible. Thus, with the RCS at reduced temperature and pressure, the consequences of a steam generator tube-sheet leakage under these conditions are significantly reduced from that of power operation. In the spring of 1996, before implementing these TS, the licensee will install new steam generators that do not require tube sheet temperature limits. All necessary heatup and cooldown rates from the existing TS are relocated to the PTLR while improved TS 3.4.1 provides the necessary limits on RCS pressure, temperature, and flow; therefore, this temperature limit is not required for safe

operation and was not incorporated into improved TS LCO 3.4.1, "RCS Pressure, Temperature, and Flow DNB Limits."

5. Existing TS 3.1.2.1.c.1 specifies the time allowed to perform an engineering analysis to determine that the RCS is acceptable to continue operation after an RCS pressure and/or temperature limit is exceeded. This time was increased from 6 hours to 72 hours. A duration of 6 hours is normally not sufficient time to perform the required engineering analysis, especially if the event were to occur during evening or early morning hours with limited support immediately available. The 72-hour Completion Time is a reasonable time to perform the evaluation as indicated in the Bases for improved TS LCO 3.4.3, "RCS Pressure and Temperature Limits (PTLs)." For a less severe P/T violation, it is possible for the evaluation to be performed in the allotted time. However, evaluations of more severe events may require complex event-specific stress analyses or inspections. If the evaluation takes longer, the plant must be shut down until the evaluation is complete. This change is less restrictive than existing TS, but most of the pressure transients experienced to date have been brief excursions and have not resulted in plant damage. The additional time allowed for these evaluations will avoid unnecessary risks associated with plant manipulations to shut down after 6 hours of evaluation and restart thereafter, but will protect against extended operation after severe pressure excursions requiring extensive evaluation. For the reasons given above, this change is acceptable to the NRC staff.

6. Existing TS 3.1.2.2, "Heatup and Cooldown Limit Curves for Normal Operation," is deleted because all heatup and cooldown rates are relocated to the PTLR and new LCO 3.4.1 specifies limits on RCS pressure, temperature, and flow. These curves are not required for safe operation of the plant; therefore, the NRC staff finds this change acceptable.

7. Existing TS 3.1.3.2 requires that in no case is the reactor to exceed a 300°F heatup and cooldown criticality limit, i.e., be made critical above and to the left of the criticality limit line of existing TS Figure 3.1-1. This requirement was deleted since improved TS LCO 3.4.2 requires compliance with the minimum RCS temperature for criticality stated in the PTLR which is well above the limit of 300°F. The minimum temperature with respect to the reactor vessel materials is contained in the PTLR and is below the limit of 540°F specified in LCO 3.4.2.

8. Existing TS 3.1.3.3 requirements were changed to require that the plant be in Mode 2 with k_{eff} less than 1.0 within 30 minutes, if T_{avg} for one or both RCS loops was less than 540°F, from the previous requirement that the plant be subcritical by an amount equal to or greater than the potential reactivity insertion due to depressurization. Improved TS LCO 3.4.2 gives clear and precise

instructions to operations personnel and ensures that the plant is quickly brought to a condition in which the LCO is no longer applicable. Although fewer requirements replace existing TS requirements, this change provides sufficient control over reactivity to ensure that the reactor is brought subcritical within 30 minutes. This brings the reactor to Mode 2 with k_{eff} less than 1.0, and improved TS LCO 3.1.1 requires that the SDM limits be met. Improved TS LCO 3.1.1 ensures that sufficient reactivity is available to offset the effects of depressurization as required in existing TS. The operating limits, together with the low probability of a depressurization event during the approach to criticality, provides an adequate level of safety. This change is consistent with the existing TS SDM curves that require the plant to borate to cold conditions once Mode 3 is reached, and with the guidance in NUREG-1431; therefore, the NRC staff finds this acceptable.

9. Existing TS 3.1.5.1.1 requirements for RCS leakage include detection system requirements for the containment sump "A" monitoring instruments for level and sump pump actuation in improved TS LCO 3.4.15, "RCS Leakage Detection Instrumentation." The sump pump monitor alarms actuate on closing of the sump pump breaker, and control room annunciators remain lit until the pump stops and the breaker opens. Control room operators log in the operation of the pump so that a sump pump actuation interval and associated leakage rate is determined every shift. These instruments replace the containment humidity detectors and the air cooler condensate flow monitor.

   The containment humidity detectors do not conform to the required leakage rate detection capability of 1.0 gpm within 4 hours as specified in Generic Letter 84-04 and are, therefore, not relied upon to detect leakage. In addition, containment humidity detectors recommended in RG 1.45 are to be used only for alarm or indirect indication of RCS leakage and not as a separate method of detecting leakage. Therefore, these requirements are not retained in improved TS 3.4.15. Instead, the current requirements for containment sump monitoring and radiation monitors are retained. These remaining leakage detection systems provide adequate monitoring. These changes are consistent with the guidance in NUREG-1431 and the assumption used in the Ginna leak-before-break analyses. Therefore, these less restrictive requirements are acceptable.

10. Existing TS 3.1.5.1 requirements for RCS leakage are modified by a Note, "LCO 3.0.4 is not applicable," in improved TS 3.4.15. This permits changes in plant mode if required RCS leakage detection systems, either the containment sump monitor or both containment atmospheric radioactivity monitors, are inoperable as long as the other requirements of TS are met. This Note is consistent with the guidance in NUREG-1431 and specifies appropriate limits for RCS

leakage detection considering the remaining systems that are available to detect and quantify RCS leakage; the limited period of time the inoperable equipment is allowed to exist; and the low likelihood of leakage that exceeds the LCO limits. Therefore, the NRC staff finds this acceptable.

11. The existing TS 3.2.5 requirement that includes an LTOP-related surveillance requirement to verify the charging pump status every 12 hours was deleted since the plant is required to be in a depressurized and vented condition within 8 hours, which removes the need to isolate a charging pump (i.e., a 1.1 square inch vent can mitigate a charging/letdown flow mismatch event). This is consistent with the guidance in NUREG-1431. This change is acceptable to the NRC staff.

12. Existing TS 3.3.1.5.e permits selected PIVs to be removed from service for up to 12 hours for repair if the in-series motor-operated isolation valve is closed. Improved TS LCO 3.4.14 Condition A specifies that a leaking PIV (check valve or motor operated) must be isolated with a Completion Time of 4 hours with a leak-tested valve, and that a second leak-tested valve must be closed within a 72-hour Completion Time. The 72-hour Completion Time to isolate the affected high pressure to low- pressure interface of the piping system is longer than the existing TS requirement to restore valve operability within 12 hours. However, closing a valve within 4 hours to isolate the inoperable valve, and the consideration that there are multiple valves protecting the high/low pressure interface, provide sufficient actions for the event. In addition, the existing TS allowed repair time is insufficient to perform most valve leakage repairs and would most likely result in reactor shutdown. The 72-hour Completion Time after exceeding the repair action requirement considers the time required to complete the action and the low probability of a second valve failing during this time period.

13. Existing TS 4.16.1.a specifies requirements for performance of the PORV channel functional test. Improved TS SR 3.4.12.6 revised the existing TS surveillance to delay performance of this test until 12 hours after decreasing the RCS temperature to the LTOP enable temperature specified in the PTLR from within 31 days preceding entering the LTOP system applicability requirements.

    This change eliminates the performance of the functional test when RCS is between 330°F (the LTOP enable temperature) and 350°F (Mode 3 lower limit) during forced shutdowns. Instead, the test can be performed within 12 hours of entering the specified condition, thereby reducing the potential for delay in the cooldown and in the operator burden in this short cooldown period. This change represents a reduction in requirements because it permits the valves to be tested later in the cooldown. The proposed test procedure is acceptable because it allows testing to proceed in a

more orderly manner, eliminates delay and, therefore, reduces operator burden to track equipment inoperability; also, the valves will be tested within 12 hours of entry into the condition for which the valves are required. The change is also consistent with the guidance in NUREG-1431.

14. Existing TS 4.3.5.3.b requires demonstration that an RHR pump is operable by performing the Inservice Pump and Valve Test Program surveillance pursuant to 10 CFR 50.55a when the reactor is at cold shutdown or when the average coolant temperature is between 200°F and 350°F and fuel is in the vessel. The status of a non-operating RHR pump in Mode 4 (RCS temperature between 200°F and 350°F) is assured by improved TS SR 3.4.6.3 which requires the verification of the breaker alignment and indicated power available to the pump. The inservice testing (IST) program ensures adequate pump performance during accident conditions; however, existing TS IST pump performance requirements exceed the performance requirements during shutdown conditions. The IST surveillance is still required for ECCS during Mode 4 as specified in improved TS SR 3.5.3.1. The removal of the existing TS 4.3.5.3.b requirements is reasonable because the RHR pumps will receive adequate surveillance testing to ensure operability below Mode 4 due to improved SR 3.5.2.4.

15. Existing TS 4.3.3.1, TS 4.3.3.2, and TS 4.3.3.3 provide leakage testing requirements for RCS pressure isolation check valves and pressure isolation motor-operated valves. The existing TS require that leakage testing be performed at greater than 150 psid for all reactor isolation valves. The requirement that leakage tests be performed with a minimum test differential pressure of 150 psid was not added to the new specifications. Improved TS LCO 3.4.14 Bases reference ASME Code Section XI as providing acceptable guidance for performing these leakage tests. This includes requirements to adjust the observed leakage rates for tests that are not conducted at the maximum differential pressure by assuming that leakage is directly proportional to the pressure differential to the one-half power. The ASME testing requirements as contained in Standard OMa-1988, require PIV leakage testing to be performed with the "full maximum function pressure differential." Leakage tests performed at lower pressures "are permitted in those types of valves in which service pressure will tend to diminish the overall channel opening, as by pressing the disk into or onto the seat with greater force." Therefore, the PIVs are to be tested using the assumed worst-case pressure differential unless this causes the valve to seat tighter, in which case a lower pressure differential is allowed with a corresponding leakage limit reduction. As such, there is no reduction in safety since the current 150 psid required minimum may, in fact, be assisting the valve in closing and meeting its leakage acceptance limits. This is a conservative change in most cases since it requires that the PIVs be tested under the maximum differential pressure conditions.

16. Existing TS 4.3.3.4 specifies four allowable leakage limits for check valves. The existing TS specify leakage rate limits that are less than 1.0 gpm but allow leakage rates of up to 5.0 gpm provided that the current test leakage rate minus the previous test leakage rate test is less than 0.5 gpm. In the improved TS, the allowed leakage rates for PIVs was adjusted from a single value for all valves to a value based on valve size to be consistent with NUREG-1431 SR 3.4.14.1 and SR 3.4.14.2. Specifying leakage rates based on size (0.5 gpm per valve diameter) results in the following new acceptance criteria: (1) Check Valves 878G and 878J (existing TS 4.3.3.2) and 877A, 877B, 878F, and 878H (existing TS 4.3.3.3) are 2-inch valves, so that their new leakage criteria will be 1 gpm compared to a maximum of 5 gpm for the existing TS, (2) Motor-operated valves 878A and 878C (existing TS 4.3.3.3) are 2 inch valves, so that their new leakage criteria will be 1 gpm compared to 5 gpm for the existing TS, and (3) Check Valves 853A and 853B (existing TS 4.3.3.1) are 5-inch valves so that their new leakage criteria will be 2.5 gpm. Check Valves 867A and 867B (existing TS 4.3.3.1) are 10 inch valves, so that their new leakage criteria will be 5.0 gpm. Both of these leakage rates are within the existing TS limit. The basis for using leakage limits based on size is contained in the NRC staff approved Standard OMa-1988. This change provides greater information of valve degradation and removes an unjustified penalty on larger valves; therefore, the NRC staff find these changes acceptable.

17. Existing TS SR 4.3.5.5 requires reactor coolant loop operability, by demonstrating that steam generator water level is equal to or greater than 16% of the narrow range instrument span for cold-shutdown conditions with the reactor not critical and for conditions when reactor power exceeds 8.5%. This surveillance was not adopted for Mode 1 operation since the low-level reactor trip function protects the SG level from not meeting the level limit assumed by the accident analysis. This change is acceptable.

18. Existing TS Table 4.1-2, "Functional Unit 15," which requires that RCS water inventory balances be performed daily was changed to every 72 hours during steady-state plant operations consistent with improved TS SR 3.4.13.1. This surveillance interval assumes that early warning of pressure boundary leakage or unidentified leakage is provided by the automatic systems addressed by LCO 3.4.15 that monitor the containment atmosphere radioactivity and containment sump level, and the alternate indications available to operators that will detect leakage (e.g., volume control tank level and radiation alarms). The NRC staff finds that this change to the frequency for performing RCS inventory balances is acceptable since the operator has several backup indications that would detect leakage and because the improved TS contain requirements to complete this SR on a more frequent basis.

19. Existing TS Table 4.1-4, "Functional Unit 1," was revised from requiring a gross specific activity determination based on gamma isotopic analysis at least once every 72 hours when above cold shutdown (i.e., T_{avg} equal to or greater than 200°F) to once every 7 days for verification of reactor coolant gross specific activity when T_{avg} equal to or greater than 500°F, consistent with the recommendations of improved TS SR 3.4.16.1. The change to the surveillance interval is based on the small probability of a gross fuel failure during the additional 4-day time period and because the 7-day interval allows proper trending of the surveillance results and remedial actions can be taken before reaching the LCO limit under normal operating conditions. Fuel failures are more likely to occur during startup or fast power changes and not during steady-state power operation during which the majority of sampling is performed. Gross fuel failures will also result in letdown system radiation alarms and possibly radiation alarms within containment, providing additional indications to the operator. The letdown system which runs continuously during reactor operation contains the R-9 radiation alarm which is an ion chamber detector with a range of 0.1 mr/hr to 10,000 r/hr specifically installed to detect possible fuel failures. Both indication and alarm for R-9 are available in the control room. The R-9 monitor has detected fuel problems in the past and is checked every shift by control room operators. Only requiring this surveillance when T_{avg} is equal to or greater than 500°F provides consistency with the LCO Applicability and is acceptable.

20. Existing TS 3.1.2.1.b requirements that the "limit lines shown in Figures 3.1-1 and 3.1-2 shall be recalculated periodically using the methods discussed in the Basis section" are not retained in the improved TS. These TS for periodically recalculating the RCS temperature and pressure curves and the RCS heatup and cooldown curve limit figures are developed on the basis of reactor vessel capsule surveillances and other factors (e.g., weld chemistry) so that figures are valid for a specified number of effective full-power years (EFPYs). The figures are recalculated if any of the factors used to generate them have changed, or if the figures are nearing the end of their specified applicability. 10 CFR Part 50, Appendix H requires a schedule for withdrawing surveillance capsules, and subsequent to their withdrawal, requires a determination if RCS temperature and pressure curves and the RCS heatup and cooldown curve limit figures need to be revised. Consequently, existing TS 3.1.2.1.b requires that recalculations be performed based on the SRs established pursuant to Appendix H; these are included as PTLR requirements referred to in Administrative Control TS 5.6.6 of the improved TS. The periodic review requirements do not need to be restated within the TS. This change avoids a duplicate requirement; therefore, this change is acceptable to the NRC staff.

21. Existing TS Table 4.1-4, "Functional Unit 3," applicability for E-bar radiochemical determination was modified to include a 31-day E-bar delay determination after a minimum of 2 effective full-power days (EFPD) and 20 days of Mode 1 operation following the reactor being subcritical for equal to or greater than 48 hours consistent with improved TS SR 3.4.16.3. The existing TS requires the sample to be taken when above 5% RTP after a minimum of 2 EFPD and 20 days of power operation since the reactor was last subcritical for 48 hours or longer. The adopted 31-day SR frequency ensures that radioactive materials are at equilibrium in order to provide a more representative sample for E-bar determination and eliminate possible false samples. This specified sampling and analysis provides a superior determination of the average decay energy of RCS constituent isotopes permitting more accurate determination of the activity of coolant samples, and is acceptable to the NRC staff.

These less restrictive requirements are acceptable, because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with current licensing practices, operating experience, and plant accident and transient analyses. They give reasonable assurance that the public health and safety will be protected.

3.3.5 Emergency Core Cooling Systems

3.3.5.1 Significant Administrative Changes

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed administrative changes to bring the existing TS into conformance with NUREG-1431 improved TS. One more significant change resulting from the administrative changes is as follows:

Existing TS 3.3.1.1.b requirements that specify the accumulator water level in terms of the percentage of accumulator volume are included in improved TS SR 3.5.1.2. Existing TS Bases page 3.3-13 contains the accumulator water volumes with respect to the indicated volume. This states that the accumulator 50% indicated level is equivalent to 1108 cubic feet of water while the 82% indicated level is equivalent to 1134 cubic feet of water. Improved TS SR 3.5.1.2 states that 50% equates to 1126 cubic feet while 82% equates to 1154 cubic feet. These changes are based on more recent calculations of the actual accumulator design and are conservative changes with respect to the accident analyses since the accident analyses were performed assuming only 1108 cubic feet and 1134 cubic feet were available. The SR specify the 50% and 82% water levels correspond to specified surveillance 3.5.1.2 accumulator volumes and therefore the values are consistent with those used in the accident analysis. As long as the accumulators are maintained within the required indicated levels of improved TS SR 3.5.1.2, the necessary volume assumed in the accident analysis

is available. This change is consistent with the guidance of NUREG-1431 and with existing TS and is acceptable.

The above change is considered a purely administrative change in the statement of requirements in the improved TS, and is therefore acceptable.

3.3.5.2 Relocated Requirements

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate all or portions of existing TS 4.5.1, "Component Tests," within the improved TS. The more significant change resulting from relocated items is the change to existing TS 4.5.2.1, Component Tests for Pumps, requires the SI and RHR pump start test frequencies and pump discharge pressures to be tested to verify acceptable levels of performance. All these requirements were relocated to the Inservice Testing Program described in improved TS 5.5.8. This is consistent with the guidance provided in NUREG-1431. The NRC staff finds this relocation to Ginna Inservice Testing program is consistent with the Final Policy statement for relocating portions of TS to programs in Administrative Controls Section of TS. These changes are considered administrative changes in the location of the requirements within the TS and are therefore acceptable.

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate or reorganize all or portions of existing TS to licensee-controlled documents.

Existing TS	Title
4.5.2.2	Component Tests - Valves.
4.6.1	Preferred and Emergency Power Systems Periodic Tests - Diesel Generators

The more significant changes resulting from relocated items are as follows:

1. The existing TS 4.6.1.e.3(b) test acceptance criteria for DG tests simulating a loss of offsite power in conjunction with a safety injection test signal were relocated to the TRM in accordance with the guidance of NUREG-1431. It is the presentation preference of NUREG-1431 to not put this level of detail in the improved TS SRs. The requirement to perform the test, however, is retained in improved TS SR 3.5.2.6. The NRC staff finds this change is in accordance with guidance of the Final Policy Statement to allow a licensee to relocate certain matters to licensee-controlled documents.

2. The licensee proposed to relocate existing TS 4.5.2.2.c requirements for the accumulators to be checked for operability each refueling outage, to the Inservice Testing (IST) program, referenced in improved TS 5.5.8. The IST program requirements specify accumulator check valve testing every refueling shutdown. The valves are currently partially stroke tested quarterly and refurbished every six years. Leakage associated with these check

valves is addressed by SR 3.5.1.2. Improved TS SR 3.5.1.2 requires verification of accumulator volume every 12 hours. The SI pumps are tested monthly by use of a test line to the refueling water storage tank (RWST). Since the SI pumps are designed with a shutoff head of approximately 1400 psig, the injection lines are not isolated from the RCS other than by the normally closed check valves. The accumulators are maintained between 700 psig and 790 psig. Therefore, if accumulator check valves were leaking, SI would force water into the accumulators during monthly tests. This level change would then be detected during performance of SR 3.5.1.2. SR 3.0.1 requires the quarterly stoke test, the six year refurbishment and the accumulator testing of SR 3.5.1.2 to be performed prior to returning to operation from any shutdown including. The relocation to the IST program is consistent with the guidance in the Final Policy statement for relocating portions of TS to licensee-controlled programs and is acceptable to the NRC staff.

The above relocated requirements relating to refueling operations are not required to be in the TS under 10 CFR 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. Further, they do not fall within any of the four criteria set forth in the Commission's Final Policy Statement, discussed in the Introduction above. In addition, the NRC staff finds that sufficient regulatory controls exist under 10 CFR 50.59 and 50.55a. Accordingly, the NRC staff has concluded that these requirements may be relocated from the TS to the licensee's TRM or the IST program as applicable.

3.3.5.3 More Restrictive Requirements

By electing to implement Section 3.5 of NUREG-1431 TSs, the licensee proposed a number of conditions that are more restrictive than those required by the existing TS. The more significant conditions are as follows:

1. The existing TS 3.3.1.5.d, Safety Injection and Residual Heat Removal Systems, permits restoring power to any valve referenced in existing TS 3.3.1.1g (valves 878B and D [open-AC, cold leg injection], 878A and C [closed, SI hot leg injection], 896A and B, and 856[open-AC, RWST]) for the purpose of valve testing provided no more than one valve has power restored and provided testing is completed and power removed within 12 hours. The improved TS 3.5.2 h provided LCO Notes which allow only valves 878B and 878D to have power during Mode 3 for the specific purpose of performing pressure isolation valve testing. These improved TS Notes address those valves that isolate low pressure portions of these systems from the high RCS pressure on the upstream portions of these systems to protect against an inter-system LOCA. For Ginna, isolation valves 896A, 896B, and 856 must have DC power removed above Mode 3 or both trains of ECCS are inoperable. The improved TS LCO Notes were needed since there is no regularly scheduled testing of 896A, 896B, 878A, 878C, and 856 above 350°F, thereby causing this test to be

performed before leaving Mode 3. The Bases for improved TS SR 3.5.2.1 and SR 3.5.2.3 further address the power requirements for valves 896A, 896B, 878A, 878C, and 856. This is consistent with the guidance of NUREG-1431. The NRC staff finds that normal system testing requirements are now being covered within the requirements and limitation of the TS rather than outside TS. When testing is performed under the guidance of TS, components rendered inoperable for testing can be systematically returned to service and are out-of-service for shorter periods of time. This change is more restrictive because the existing TS allows power to be restored for up to 12 hours without entering the LCO. The NRC staff finds this ensures the availability of all required systems to meet the postulated design basis events assumed in the safety analyses.

2. The existing TS do not contain any requirements for the ECCS to be operable while in Mode 4 as is included in the NUREG-1431 guidance document. The licensee has agreed to add this new LCO 3.5.3, ECCS - Mode 4 to the improved TS. This TS requires one train of SI or RHR to be operable during Mode 4. New Conditions provide required actions if either train is found to be inoperable. SR 3.5.3.1 provides reference to the applicable SRs within LCO 3.5.2 to ensure the ECCS train is operable. This new requirement is being added to address low probability accidents which may occur during this mode of operation that are not in the existing Ginna licensing basis, and thus continue to ensure safe conduct of operations at the plant.

3. Existing TS 3.3.1.1.b requires accumulator operability above reactor coolant system pressures of 1600 psig, except during hydro tests. The hydro test exception was not incorporated into improved TS LCO 3.5.1, "Accumulators," because the LCO requires accumulator operability in Mode 3 when pressures are above 1600 psig and accumulator hydro tests are performed with RCS temperatures below Mode 3 (less than 350°F) conditions and less than 1600 psig. The deletion of the exception to the requirement is consistent with the guidance of NUREG-1431, is consistent with plant testing practices, and is acceptable.

4. The improved TS 3.5.2, ECCS - Modes 1, 2 and 3, has added a new SR 3.5.2.1 which requires verification that ECCS related isolation valves (with their listed function) are in their required position every 12 hours. These valves are currently required to be operable in existing TS 3.3.1.1.g, 3.3.1.1.i, and 3.3.1.1.j; however, there is no verification of their correct position in the ECCS flow path. This improved TS SR augments existing requirements by this frequent check via the control board indication of valve position. The NRC staff finds this verification minimizes the potential of any misaligned valves which could render an ECCS train inoperable, thus this maintains the assumptions of the ECCS safety analyses.

5. The improved TS 3.5.2, ECCS - Modes 1, 2 and 3, has added a new SR 3.5.2.2 which requires verification that ECCS related valves which are not locked, sealed, or otherwise secured in position are in their correct position every 31 days. This new SR further augments existing TS requirements by performing an ECCS system walk-down. This does not involve any valve testing or manipulation. The addition of SR 3.5.2.2 verifies valve alignments assumed in the ECCS safety analyses.

6. The improved TS 3.5.1, Accumulators, has added a new SR 3.5.1.1 which requires verification every 12 hours that each accumulator motor-operated isolation valve is fully open above 1600 psig. This verification ensures that the accumulators are available for injection and ensures timely discovery if a valve should be less than fully open. The NRC staff concludes it is highly unlikely a motor-operated valve could change position with the power removed, thus, this verification fully supports the assumption made in the accident analyses.

7. The improved TS 3.5.1, Accumulators, has added a new SR 3.5.1.3 which requires verification every 12 hours of the nitrogen pressure in the accumulators to prevent lifting of the relief valve and overpressurization of the tank. Since accumulator pressure is relatively static, the 12-hour frequency is sufficient to allow most changes in pressure to be detected and corrected by the operator before limits are reached. A value of 790 psig was selected since it is above the accumulator pressure upper alarm setpoint of 760 psig and below the relief valve setpoint of 800 psig. Safety injection during a LOCA injection will be assured at any value above 700 psig pressure. The NRC staff concludes that this new verification will ensure the reliable operation of the accumulators during a postulated LOCA event in the ECCS safety analyses.

8. The improved TS 3.5.1, Accumulators, has added a new SR 3.5.1.4 which requires verification of boron concentration in the accumulator, since this limit is used in determining the time frame from which boron precipitation is addressed in the LOCA analysis. The value of 2600 ppm was selected since this would not create the potential for boron precipitation in the accumulator assuming a containment (and accumulator) temperature of 60°F. The NRC staff finds this is acceptable because this is also bounded by the containment sump Ph calculations and assumptions used for chemical spray effects.

9. The improved TS 3.5.4, Refueling Water Storage Tank, has added a new SR 3.5.4.2 which requires verification every 7 days of an upper limit for boron concentration in the RWST. This limit is used in determining the time frame in which boron precipitation is addressed in the LOCA analysis. The boron concentration is a cycle dependent variable, i.e., to provide sufficient negative reactivity

but not so much to cause a precipitation problem. The amount needed will depend on the makeup of the core. The specified concentration is assumed in the FSAR as a limit that does not create the potential for boron precipitation in the RWST provided an Auxiliary Building (and RWST) temperature of 50°F is maintained. This concentration is also compatible with the containment sump Ph assumptions and requirements used for chemical sprays to control effects of chloride and caustic stress corrosion on mechanical systems.

10. The licensee adopted improved TS SR 3.5.2.7 requirements for visual inspection of RHR containment sumps to verify that the pump suction inlet is not occluded with debris and that the sump screen is structurally sound. The periodic inspections ensure the RHR pumps are capable of using the containment sump as a source of coolant following a design basis LOCA.

11. The licensee adopted improved TS SR 3.5.2.1 requirements for verifying that breaker and key switch positions as applicable, are in their correct positions. This requirement ensures that an active component failure could not result in an undetected mispositioning of a valve which affects both trains of ECCS.

12. Existing TS 3.3.1.1.b provides a minimum accumulator boron concentration limit of 1800 ppm with no upper limit. The licensee adopted improved TS SR 3.5.1.4 which specifies a boron concentration of 2100 ppm and an upper limit of 2600 ppm. The more limiting lower limit is in support of the change to 18-month fuel cycles beginning in the spring of 1996. The Ginna accident analyses have been re-performed using 2100 ppm boron concentration for the lower limit. The new 2600 ppm upper limit is consistent with existing accident analyses assumptions, and the recommendations of NUREG-1431 and continues to ensure that the sump fluid following an accident remains within the assumptions for chloride and caustic stress corrosion on mechanical systems and components.

13. Existing TS 3.3.1.1.a provides a minimum RWST boron concentration limit of 2000 ppm with no upper limit. The licensee adopted improved TS SR 3.5.1.4 which specifies a boron concentration of 2300 ppm and an upper limit of 2600 ppm. The more limiting lower limit is in support of the change to 18-month fuel cycles beginning in the spring of 1996. The Ginna accident analyses have been re-performed using 2300 ppm boron concentration for the lower limit. The new 2600 ppm upper limit is consistent with existing accident analyses assumptions and the recommendations of NUREG-1431 and continues to ensure that the sump fluid following an accident remains within the assumptions for chloride and caustic stress corrosion on mechanical systems and components.

The NRC staff reviewed the above more restrictive requirements and concludes that they enhance the improved TS. Therefore, the more restrictive requirements are acceptable.

3.3.5.4 Less Restrictive Requirements

In electing to implement the Section 3.5 specifications, the licensee proposed a number of conditions that are less restrictive than those that are allowed by the existing TS. The more significant conditions are as follows:

1. Existing TS 3.3.1.1.b and 3.3.1.3 establish requirements for accumulator operability. Improved TS LCO 3.5.1 provides a 72-hour Completion Time instead of the existing 1-hour Completion Time to restore accumulator boron concentration to within limits.

   Once it is determined that the accumulator boron concentration needs to be changed, operations and chemistry must first calculate the required boron to be added. The accumulator is then drained to just above the TS minimum required level and the borated water added from the RWST. Depending on the initial accumulator boron concentration, the tank may need to be drained and filled several times to reach the required limit since the RWST is maintained at a minimum of 2000 ppm and there is only 25 cubic feet of water volume in the accumulator to work with. Since these actions can take longer than one hour to complete, the licensee has adopted stricter procedural limits to maintain accumulator boron concentration sufficiently above the TS limit such that remedial actions are initiated before TS limits are reached. This is performed in part by checks of accumulator level every shift.

   Allowing a longer period of time to correct boron concentration is acceptable since the volume of water in the accumulators is the most important feature for ensuring that the accumulator safety function is met, due to the amount of boron available from the RWST, as indicated in the Ginna accident analysis. The critical accident scenario with respect to boron concentration is a steam line break for which the accumulators do not inject.

   A 1-hour time limit to reestablish the limiting boron concentration creates a significant burden on the operations staff. Therefore, the existing 1-hour Completion Time was only maintained for accumulator pressure and volume stated in condition B of improved TS 3.5.1. These changes are consistent with the guidance of NUREG-1431.

2. The limits for restoring RWST boron concentration in existing TS 3.3.1.1.a and 3.3.1.2 within 1 hour are changed to incorporate improved TS LCO 3.5.4, refueling water storage tank limits of condition A which allow an 8-hour Completion Time instead. The increased completion time to correct boron concentration is acceptable because the large volume of water contained within the

RWST requires a significant amount of time to perform this adjustment and the fact that the contents of the tank are still available. This change is consistent with the guidance of NUREG-1431 and is acceptable to the NRC staff.

3. Existing TS 3.3.1.1.c requirements are included in improved TS LCO 3.5.2, "ECCS Modes 1, 2, & 3" notes to the Applicability statement. The first Note allows both SI pump flow paths to be isolated for up to 2 hours in Mode 3 to perform pressure isolation valve testing. This is acceptable for this limited amount of time since the isolation valves can be opened from the control room or remotely by licensee personnel. The second Note allows up to 4 hours, or until the RCS cold legs exceed 375°F, to place into service the ECCS pumps declared inoperable due to LTOP considerations. This Note was added since the LTOP arming temperature setpoint of 330°F, below which the pumps cannot be capable of injecting coolant into the RCS, is close to the Mode 3 boundary temperature definition of equal to or greater than 350°F, where the pumps must be operable. This Note provides a reasonable amount of time to restore inoperable pump(s) to operable status for entry into Mode 3 and avoid unwarranted delays. These changes are consistent with the guidance of NUREG-1431.

These less restrictive requirements are acceptable, because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with current licensing practices, operating experience, and plant accident and transient analyses. They give reasonable assurance that the public health and safety will be protected.

3.3.6 Containment Systems

3.3.6.1 Significant Administrative Changes

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed administrative changes to bring the existing TS into conformance with NUREG-1431 improved TS. The more significant changes resulting from these administrative changes are as follows:

1. The revised presentation of actions in the improved TS do not propose to explicitly detail the most obvious option "to restore .... to operable status." This action, stated in the existing TS, is not repeated in the improved TS because this option is implicit in all conditions. Therefore, this provision is unnecessary, and omitting this action is purely editorial.

2. The improved TS LCOs, where appropriate, contain action Note terminology such as ... "Separate Condition entry is allowed for each component or subsystem." This guidance is implicitly utilized in the interpretation of the existing TS. It is the presentation preference of the guidance in NUREG-1431 to explicitly state this instruction. The justification provided with improved TS 1.3,

"Completion Times," further describes the use of this terminology. This language is purely editorial in nature.

3. The deletion of the Definition 1.8, "Containment Integrity," has been replaced by three separate Limiting Conditions for Operation (LCOs). They are Containment (LCO 3.6.1), Containment Air Locks (LCO 3.6.2), and Containment Isolation Boundary (LCO 3.6.3). The previous elements of the Containment "Integrity" definition are now individually specified in these separate improved TS LCOs. The operability requirements collectively defined in these improved TS are equivalent to the existing TS 1.8 definition of the component/system integrity. Therefore, these changes are editorial in nature, involving the movement or reformatting of requirements that remain applicable without affecting the technical content.

4. The existing TS 4.4, "Containment Tests," establish requirements for the Integrated Leakage Rate Test (CTS 4.4.1) and the Local Leak Detection Tests (CTS 4.4.2). These tests are conducted in accordance with 10 CFR Part 50, Appendix J, as modified by approved exemptions. The requirements comprising a set of strict prescriptive rules, implement, in part, General Design Criterion 16. GDC 16 mandates "an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment for postulated accidents." In September 1995, Appendix J was amended to provide an alternative approach to the prescriptive requirements method. This new approach is known as Option B "Performance Based Requirements." Ginna has adopted Option B as allowed by Appendix J, and has administratively incorporated this option as another part of the TS Improvement Program under the implementation guidelines of the amended Appendix J. This change is neither less-restrictive nor more restrictive, because the licensee is continuing to perform containment leakage rate testing in accordance with the requirements of 10 CFR Part 50, Appendix J, under a new "Containment Leakage Rate Testing Program," as described in Administrative Controls Specification 5.5.15. "P_a" is defined in Specification 5.5.15, along with all the leakage rate criteria for Type A, B, and C tests and test acceptance criteria for the air locks and the mini-purge valves. The Option B performance-based approach would allow licensees with good performance testing to reduce the Type A testing frequency from three tests in 10 years to one test in 10 years. For Type B and C tests, Option B would allow licensees to reduce testing frequency based upon experience history of each component, and establishes controls to ensure continued performance during the extended testing interval. The licensee will perform all testing in accordance with Regulatory Guide 1.163, "Performance-Based Containment Leakage Test Program," dated September 1995. An evaluation of the licensee's Containment Leakage Testing requirements and changes made thereto is provided in Section 4.3 of this report.

The above changes are considered purely administrative changes in the statement of requirements in the improved TS, and are therefore acceptable.

3.3.6.2 Relocated Requirements

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate or reorganize all or portions of existing TS to licensee-controlled documents.

Existing TS	Title
3.6.5	Containment Mini-Purge
4.5.2.1	Component Tests-Pumps
4.5.2.3	Air Filtration System

The more significant changes resulting from relocated items are as follows:

1. Existing TS 3.6.5 requires that the mini-purge valves be closed to the maximum extent possible, except that they may be opened under the conditions stated therein. This existing LCO does not meet any of the four LCO TS criteria set forth in the Commission's Final Policy Statement, nor does it specify any required actions. Existing TS 3.6.5 is essentially a surveillance requirement, which is added to the improved TS as SR 3.6.3.1. The mini-purge system is operated under administrative controls such that its use is strictly controlled. For Ginna, these valves are verified to be closed, but the existing TS do not state any required interval. Therefore, the new verification that the mini-purge valves are closed every 31 days is an appropriate frequency check commensurate with current plant operations. By relocating the "opening" requirements that restrict the use of these valves to the Bases, future changes are controlled by 10 CFR 50.59. The NRC staff finds that this TS change maintains the safe operation of the mini-purge system valves, as previously provided in the existing TS, and is acceptable.

2. Existing TS 4.5.2.1.b., "Component Tests for Pumps," requires that the containment spray pumps be tested to verify they state acceptable levels of performance. The existing TS requires that all pumps shall be started, operated, and verified to develop the minimum discharge pressure for the required flows, in accordance with American Society of Mechanical Engineers (ASME) Section XI for inservice testing (IST). The improved TS have retained these requirements; however, they are now included in the inservice testing program requirements located in Specification 5.5.8 of the Administrative Controls section of the improved TS. Any testing details, procedural steps, or exceptions specified in the existing TS are relocated to the IST Program. Therefore, the improved TS SR 3.6.6.7 requires that all CS pumps have a developed head at the flow test point that is be greater than or equal to the required head in accordance with the IST Program. The IST Program contains the specific test flow rates and discharge pressure requirements

for all pumps tested in the IST Program consistent with the guidance provided in NUREG-1431. Changes to these limits are controlled by 10 CFR 50.55a(f).

3. The requirements of existing TS 4.5.2.3, "Air Filtration System" (which apply to the containment recirculation fan cooling and the containment post-accident charcoal systems) state the various system test requirements for ensuring that the air filtration system is operable. In addition, several precautions are identified to replace and test charcoal drawers and HEPA filters after any structural maintenance on the housing of either the post-accident charcoal system or the containment recirculation system. These requirements and precautions were not added to the improved TS under SRs 3.6.6.10 and 3.6.6.11. This level of detail is relocated to procedures for the Ventilation Filter Testing Program described in new Specification 5.5.10. These relocated details do not provide the operator any necessary information and need not be retained in the TS.

The above relocated requirements relating to containment systems are not required to be in the TS under 10 CFR 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. Further, they do not fall within any of the four criteria set forth in the Commission's Final Policy Statement, as discussed in the Introduction above. In addition, the NRC staff finds that sufficient regulatory controls exist under 10 CFR 50.59 or 10 CFR 50.55a(f). Accordingly, the NRC staff concludes that these requirements may be relocated from the TS to the licensee's TS Bases, IST, or plant procedures, as applicable.

3.3.6.3 More Restrictive Requirements

By electing to implement the Section 3.6 NUREG-1431 specifications, the licensee adopted a number of conditions that are more restrictive than those required by the existing TS. The more significant conditions are as follows:

1. Existing TS 3.3.2.2.a through f provide the allowed outage times for various components of the containment cooling and iodine removal system. Existing TS 3.3.2.2 also provides the minimum complement of components required to remain operable to meet the analyzed accident assumptions when the full complement of equipment is not available. If these requirements are not satisfied, the existing TS require that the reactor be placed in hot shutdown within 6 hours. If the requirements are still not satisfied in an additional 48 hours, the reactor is placed in Mode 5 within the next 30 hours. The improved TS shortened the length of time that the plant is in the shutdown track at the end of the completion times for the conditions when the plant is required to shut down due to problems with the fan cooler units. Under the improved TS, the plant now has only 36 hours to reach Mode 5, versus the 84 hours previously allowed. This change is consistent with the plant

shutdown times for other LCOs. The NRC staff also finds that this change is acceptable based upon the importance of maintaining containment pressure and temperature control at all times. The NRC staff finds these new requirements will ensure the continued safe operation of the Ginna.

2. Existing TS 3.6.2, "Internal Pressure," restricts the containment internal pressure from exceeding an upper and lower pressure limit only while the reactor is critical. The improved TS 3.6.4 extends the applicability of this requirement to include the time after the reactor becomes subcritical and until T_{avg} is reduced to less than 200°F. This is the new Ginna-defined Mode 4. This new requirement ensures that containment internal pressure is verified to be within limits for a longer period during operational modes than previously required. The NRC staff finds that this improved TS requirement increases safety above the conditions allowed in the existing TS.

3. Existing TS 3.6.2, "Internal Pressure," permits the containment internal pressure to exceed either the upper or lower pressure limit for 24 hours before requiring an orderly shutdown. The improved TS 3.6.4 Completion Time limits this inoperable condition to 8 hours, rather than adopting the current Ginna licensing basis. Ginna has a large containment-free volume, and the limited size of the containment mini-purge system requires several hours, depending upon the initial pressure, to restore pressure to within limits. New SR 3.6.4.1 requires that the pressure be checked once every 12 hours. These tightened requirements further reduce the risk of this system's design parameters being outside the assumptions of the safety analyses. The NRC staff finds that these changes enhance safe operation of the plant.

4. The existing TS 3.6.3 defines requirements for containment isolation boundaries, rather than requirements for specific components (such as air locks, isolation valves, etc.). The existing TS 1.8 definition for Containment Integrity requires only one intact boundary to be operable in the various potential leakage flow paths out of containment. Improved TS 3.6.2, "Air Locks" and TS 3.6.3, "Containment Isolation Boundaries," specify further controls of this boundary to apply equally to a redundant boundary now defined within each containment system's leakage flow path. For airlocks, this redundancy is now two operable air lock doors. For containment isolation valve flow paths, this redundancy is isolation devices such as manual valves, blind flanges, deactivated automatic valves, check valves with the flow through the valve secured, end caps, transmitters, and closed systems. This difference evolved over the station's operational life because the plant was designed before implementation of GDCs in 10 CFR Part 50, Appendix A. The proposed change eliminates this difference by imposing consistently the guidance provided in NUREG-1431 and the licensing requirements for newer plants. This change also ensures that the previous NRC reviews and acceptances of the existing

containment integrity design in numerous SEs, Systematic Evaluation Programs, and post-TMI responses will remain in effect. The NRC staff finds that there are two fully functional containment boundaries in place to preserve the containment integrity at these affected penetration flow paths; consequently, this exceeds the assumptions of the safety analyses and is acceptable.

5. Existing TS 3.6.3.a, "Containment Isolation Boundaries," requires that all inoperable containment penetrations be restored to operable status within 4 hours, regardless if it is an air lock, CIV, or any flow path outside containment. Improved TS 3.6.2 contains Required Actions within all new conditions, which require that an operable air lock door be locked closed within 1 hour. In addition, improved TS 3.6.3 has added a new Condition B, which limits the Completion Time to 1 hour when both required isolation valves in a penetration flow path are inoperable. These changes to the improved TS ensure that containment integrity is potentially violated for less time than currently allowed by the existing TS. The basis for 1-hour limitation is consistent with the Completion Time of improved TS 3.6.1. This change follows the guidance provided in NUREG-1431, and is applicable for Ginna. The NRC staff finds that this improved TS requirement increases safety above the conditions allowed in the existing TS.

6. Existing TS 3.6.3 requires that an inoperable air lock be restored to operable status within 4 hours. The existing TS 1.8 definition of Containment Integrity requires only one operable boundary to maintain containment integrity, so it states that only one door in each personnel air lock needs to be closed and sealed.

   The improved TS 3.6.1 Bases for containment operability state that the air lock is operable except as provided in LCO 3.6.2. This implies that both doors are operable and provide containment boundaries. Improved TS 3.6.2, "Air Locks," provides Conditions A, B, and C, which specify new required actions as alternatives to simply restoring the air locks to operable status. These new conditions derive from NUREG-1431, and are applicable to Ginna. The required actions for Conditions A and C ensure that each air lock always has at least one operable door closed at all times to preserve containment operability until the inoperable door or air lock is restored to operable status. The required actions require continuing periodic verifications to ensure that the remaining operable door is closed and locked while in each condition for the specified completion times.

   Similarly, Condition B pertains solely to an inoperable air lock interlock mechanism. If access into containment is desired, Note 2 permits an individual to be stationed at the air lock and dedicated to ensuring that two doors are not open simultaneously and one door is re-locked before to leaving. This individual thus provides substantially the same level of protection as if the interlock mechanism were operable. The condition further permits periodic verification that the air lock door remains locked until the interlock mechanism is returned to operable status and the condition is exited. Additionally, the licensee added various action and required action Notes to these respective new conditions to facilitate the active use of the air lock for routine containment entries, and for the purpose of making required repairs.

The NRC staff finds that these new conditions, actions, and equivalent required actions ensure that the closed operable door matches the assumptions of an intact containment boundary in the accident analyses.

7. Existing TS 3.6.3 and 4.4.2.4.a require containment penetrations to be operable and tested in accordance with Appendix J; however, the existing TS are deficient because they do not establish air lock test acceptance criteria as required by Appendix J. Likewise, existing TS 4.4.2.3.c defines a leakage limit only for the mini-purge valves, but lacks an allowable out-of-service time limit for not being met. The improved TS LCOs 3.6.2 and 3.6.3 each have an actions Note to require entry of the required actions of LCO 3.6.1 if the components in the containment isolation boundary are inoperable such that the overall containment leakage rate acceptance criteria are exceeded. This requires that the overall containment leakage rate be evaluated immediately to determine whether or not the applicable criteria are exceeded.

   Air lock leakage limits for Ginna and the leakage limits for the mini-purge valves have now been defined in Specification 5.5.15, which implements the "Containment Leak Rate Testing Program." Improved TS 3.6.3, Conditions D and E, which are new for Ginna, provide requirements for the mini-purge penetrations. These requirements specify that the affected penetration must be isolated, that the isolation of the penetration must periodically be verified, and that the overall containment leakage rate criteria must be evaluated. The addition of these new requirements to the Ginna licensing basis formalizes the Appendix J requirement. The NRC staff finds that these changes further enhance the control of these potential leakage flow paths, and thus maintain the integrity of the containment boundary as assumed in the safety analyses.

8. The existing TS do not establish LCOs for containment air temperature. In the improved TS, the licensee added LCO 3.6.5, as provided in the guidance of NUREG-1431, but allows 24 hours to restore temperature to within limits as compared to the 12 hours suggested by NUREG-1431. Additionally, SR 3.6.5.1 verifies that the containment air temperature limits are met every 12 hours during each shift, rather than daily as specified in the guidance document. The frequency of this verification is increased and the Completion Time is extended because the large containment

atmosphere requires at least 14 hours to exchange one volume via the mini-purge valves, in the unlikely event that containment cooling is not available as required. The NRC staff finds that these new requirements enhance safe operation of the plant and further reduce the risk of this system's design parameters being outside the assumptions of the safety analyses.

9. The existing TS do not establish LCO requirements for the hydrogen control system. Using the guidance of NUREG-1431, the licensee added an improved TS LCO 3.6.7, which requires that the hydrogen recombiners are operable in Modes 1 and 2. In the accident analyses, the hydrogen recombiners are assumed to be used to prevent a hydrogen explosion within containment that could overpressurize the containment structure.

   The LCO also allows 30 days to restore an inoperable recombiner and 7 days to restore two inoperable recombiners if the mini-purge system is operable. The NRC staff previously accepted the use of the mini-purge system as an alternative hydrogen control system under the NUREG-0737 evaluations. This added LCO includes three SRs to be performed at each refueling. Specifically, SR 3.6.7.1 requires a functional check of each recombiner as defined in the Bases; SR 3.6.7.2 requires a visual examination for no evidence of abnormal conditions; and SR 3.6.7.3 requires a CHANNEL CALIBRATION of each recombiner actuation and control channel.

   The NRC staff finds that these new LCO and SR requirements ensure that the assumptions made in the safety analyses are maintained with regard to detecting and controlling the hydrogen generation rates below explosive limits.

10. The existing TS do not establish an LCO requirement to verify the spray additive tank level. In the improved TS, the licensee added this requirement as new SR 3.6.6.8. The previous control for the spray additive tank only verified Sodium Hydroxide (NaOH) concentration. This new verification ensures that there is also sufficient volume of spray additive, as determined by measuring the height of liquid contained in a tank of known shape and volume. In addition, this tank level is indicated and alarmed in the control room, so there is a high degree of confidence that any substantial change would be immediately detected. The NRC staff finds that these additional verifications help to ensure the safety of the plant.

11. Existing TS 4.4.2.3.a and 4.4.2.3.b require that repairs begin immediately for all penetrations or containment leakage paths that exceed the $0.6L_a$ leakage limit individually or in combined leakage. If the repairs do not return the affected leaking component(s) to operable status within 48 hours, the reactor must be shut down. Improved TS 3.6.1 has shortened this allowed outage time to 1 hour. The NRC staff concludes that this reduced outage time allowance

provides prudent and concise actions in the improved TS, which were not as prescriptive in the existing TS. The NRC staff finds that this proposed change reduces the period in which the containment boundary may be degraded, and allows a limited restoration time given the need to restore containment operability.

12. The existing TS do not establish LCO requirements to verify operability of the containment air lock door interlock mechanism. In the improved TS, the licensee added SR 3.6.2.2 to perform this test at refueling. This change enhances the reliability of this mechanism to function as designed should it be improperly challenged, in contradiction to administrative controls already in place at Ginna. The NRC staff finds that this establishes a more comprehensive set of requirements for determining the operability of the air locks, and thus ensures safe operation of the plant components.

13. Existing TS 4.4.5.1 requires only that containment isolation valves meet the IST program requirements (e.g. isolation times) to be considered operable. In the improved TS, SRs 3.6.3.2 and 3.6.3.3 require explicit verification of the position of each isolation valve. The frequency for performing these verifications is 92 days for valves located outside containment. For valves located inside containment, the interval is before entering Mode 4 from Mode 5 if not performed within the previous 92 days. An exception to this verification is that valves in high-radiation areas may be verified using administrative controls. The NRC staff finds that this change improves the safety of operations at the plant by requiring frequent walkdowns to verify the component alignments in each containment isolation penetration flow path. The NRC staff finds that this establishes a more comprehensive set of requirements for determining that containment isolation valves are operable and in their correct pre-accident position, as assumed in the safety analyses.

14. Existing TS 4.5.1.2, "Containment Spray System," requires a system test only at refueling. In the improved TS, the licensee added SR 3.6.6.2 to verify the correct position of each manual, power operated, and automatic valve in the CS flow path that is not locked, sealed, or otherwise secured in position. Every 31 days, operators verify the status of each CS flow path component during a system walkdown. This surveillance ensures that the CS system components are aligned to operate as required. The NRC staff finds that this verification adds another level of assurance that the system has not been unintentionally misaligned by routine maintenance operations, which are also intensively monitored.

15. The improved TS include SR 3.6.6.12 to verify that the CS motor-operated isolation valves actuate to their correct position once every 24 months following an actual or simulated safety injection (SI) signal. The CS pumps were tested monthly, but existing TS do

not contain surveillance requirements to verify valve alignment in the CS train. The NRC staff finds that this improved TS requirement increases safety by providing additional assurance that this system will be available if called upon to operate during an accident.

16. The improved TS includes SR 3.6.6.1 to verify spray additive flow through each eductor path every 5 years. This SR ensures that the correct pH level is established in the borated water solution by ensuring that the right amount of NaOH will be induced into the flow path upon initiation of the containment spray system. Because of the passive nature of the spray flow controls, the 5-year frequency is sufficient to identify component degradation that may affect flow rate. The NRC staff that finds this improved TS requirement increases operational safety relative to the existing TS.

17. Existing TS 4.5.2.3.3 and 4.5.2.3.4 require functional tests of replaced containment recirculation fan cooler components; however improved TS SR 3.6.6.2 requires that each CRFC unit be operated for at least 15 minutes once every 31 days. This test ensures the operability of the CRFC units, in accordance with the LCO. The NRC staff finds that these specific tests help to ensure the continued safe operation of the plant.

18. Existing TS 4.5.2.3.3 and 4.5.2.3.4 require tests on the individual containment recirculation fan components but no integrated system testing. In the improved TS, the licensee added SR 3.6.6.14, which requires that the CRFC units start on an actual or simulated safety injection (SI) signal once every 24 months. These tests ensure operability of the CRFC units, in accordance with the LCO. The NRC staff finds that this improved TS requirement increases safety above the allowances in the existing TS.

19. Improved TS SR 36.6.5 requires verification that cooling water is flowing through the fan coolers every 31 days. This ensures that the heat removal capability of the CRFC units is operable as assumed in the accident analysis.

The NRC staff reviewed these more restrictive requirements, and concludes that they enhance the existing TS. Therefore, these more restrictive requirements are acceptable.

3.3.6.4 Less Restrictive Requirements

In electing to implement the Section 3.6 specifications of NUREG-1431, the licensee proposed a number of conditions that are less restrictive than those allowed by the existing TS. The more significant conditions are as follows:

1. Existing TS 3.3.2.2, "Containment Cooling and Iodine Removal," requires one containment spray pump, three fan cooler units, three

HEPA filter units with demisters, one charcoal filter unit, and all required valves and associated piping with these components to be operable. In the improved TS LCO 3.6.6, the licensee corrected an error in the existing TS with respect to the number of fan cooler units and HEPA filter units required to be operable. Specifically, the licensee reduced the number of units required to be operable from three to two (for each type of unit). This change provides consistency with the accident analyses, which demonstrate that either two CS trains, one CS train and one post-accident charcoal filter train, or two post-accident charcoal filter trains are adequate to remove radioactive iodine from the containment atmosphere following a DBA. (That is, each CS train and post-accident charcoal filter train provides 50% of the required iodine removal requirements.) However, two CS trains cannot be inoperable, since at least one train and two CRFC units must operate to maintain containment pressure and temperature control.

Based upon the these changes, the licensee added improved TS Conditions C and F. Improved TS Condition C, a new Ginna requirement, allows 72 hours to repair two inoperable charcoal filter units. This completion time is consistent with allowed outage times for systems with redundant trains. Improved TS Condition F was added which permits 7 days to restore 2 fan coolers. This Completion Time is acceptable since CS and a second 100% redundant train of CRFC units are operable. The NRC staff finds that this change is acceptable because the LCO is consistent with the assumptions of the accident analyses for a LOCA and steam line break.

2. Existing TS 3.6.3 requires containment isolation "boundaries" to be operable in Modes 1 through 4. The Bases for existing TS 3.6.3 specify that the containment isolation boundaries include "closed systems"; however, later in the Bases, the allowable means for isolating the failed containment boundary does not include the use or reliance upon a closed system boundary.

   Improved TS 3.6.3 establishes the requirements for use of a closed system as an acceptable boundary to isolate a containment penetration for up to 72 hours. Improved TS Condition C is applicable only to penetration flow paths that use a closed system as a containment isolation boundary. Required actions to isolate the inoperable containment isolation boundary are similar to these requirements for Conditions A and B, except that these penetrations do not have the redundant isolation valves. The intact and operable closed system becomes the redundant boundary in this penetration to maintain the assumptions of the safety analyses for containment isolation.

   The NRC staff finds that this is acceptable, because a closed system is not subject to an active failure. (That is because the closed system is a Class II passive piping system that is protected

against pipe whip and missiles.) The probability of a closed system failing to be intact is low because any leakage through the closed system boundary can also be detected during normal system operation, inservice testing of associated pumps and valves, and operator walkdowns during which leakage from a filled pipe can be seen on the floor.

The Completion Time for Condition C is 72 hours to isolate or restore a failed isolation valve. This interval is acceptable based on the high reliability inherent in a passive barrier resulting from no requirements for operator action to perform the isolation function. This period also provides adequate time to perform most repairs based upon the operational history for various inoperable containment isolation valves. In addition, increasing the allowed outage time from 4 hours to 72 hours is consistent with the times provided in NUREG-1431 when restoring one train of a two-train system. The NRC staff finds that, during this short period of time, the closed system relied upon is an intact boundary that cannot be adversely affected by a single active failure. The NRC staff concludes that it is improbable that a DBA could occur during this limited time, and that this situation does not add significant risk beyond what has already be assumed and determined in the safety analyses.

3. The existing TS Table 4.1-2, "Minimum Frequencies for Equipment and Sampling Tests," Functional Unit #13 requires the that NaOH content of the spray additive tank be checked monthly. In the improved TS, SR 3.6.6.8 changed this requirement to every 184 days. This change is acceptable, since the spray additive tank is normally isolated at power such that changes to the NaOH concentration or level are not expected. The tank makeup path is from the primary water treatment system. The use of this path requires the opening of five normally closed, in-series valves. One of these valves is maintained locked in the closed position to further prevent dilution. The NRC staff finds that the inadvertent dilution of the spray additive tank is prevented to the fullest extent possible by use of administrative controls and verifications in the improved TS.

4. Existing TS 4.4.2.4.c requires that an air lock door seal be tested within 48 hours of each opening, except during cold shutdown. This requirement was provided to Ginna as an exemption when the original Appendix J rule was adopted. Rather than retesting after each opening, Ginna was granted permission to retest only after the first in a series of openings. The licensee has now proposed to eliminate this exemption and follow the current requirement of Appendix J, Option B. This licensing approach is consistent with most current operating reactors. The NRC staff finds this acceptable because operating experience has shown that this test result is generally acceptable at all times when performed.

5. Existing TS 4.5.2.1.a, "Component Tests for Pumps," requires that the containment spray pumps be tested once every month, except during cold shutdown or refueling operations. The improved TS SR 3.6.6.4 relocates all CS pump testing frequencies and discharge pressure requirements to the IST Program described in Specification 5.5.8. This is consistent with the guidance provided in NUREG-1431; as compared to existing TS monthly testing this relaxes the frequency of these tests to 92 days or quarterly. These tests are conducted in accordance with the requirements of ASME Section IX. The NRC staff finds that this change is consistent with the recommendations of NUREG-1366, "Improvements to Technical Specification Requirements," which suggest that monthly testing of pumps be changed to quarterly testing. Additionally, the NRC staff finds that current operating experience at licensed reactors in conducting this type of component test has demonstrated that these pumps are generally found to meet the original design system parameters.

6. Existing TS 4.5.1.2.b requires that the spray nozzles be checked for proper functioning at least every 5 years. Improved TS 3.6.6.18 extends the interval for performing the spray nozzle gas test to once every 10 years. The increased surveillance interval is considered acceptable because of the passive nature of the spray nozzles. In addition, previous acceptable results show that no nozzles have been obstructed from flow. This change implements the guidance contained in NUREG-1431, and is applicable for Ginna. The NRC staff approves this change because it is consistent with the recommendations in NUREG-1366, "Improvements to Technical Specification Requirements," which suggest that nozzle flow testing be extended to a 10 year interval. This is based upon historical test results showing a lack of significant problems discovered by this verification.

7. Existing TS 4.5.2.3.5 requires that the post-accident charcoal filter isolation valves be tested monthly. Improved TS SR 3.6.6.15 was revised to require actuation of the post-accident charcoal filter dampers from an actual or simulated SI signal only once every 24 months to ensure that the system correctly aligns itself, Improved TS SR 3.6.6.6 requires that the post-accident charcoal filter dampers must still be opened at least once every 31 days to allow the system to operate for at least 15 minutes, as stated in the existing TS. Consequently, the licensee only revised the frequency with which the dampers are automatically aligned. This is consistent with the system surveillance requirements provided in NUREG-1431. The NRC staff finds that these verifications continue to ensure the post-accident function of the system is maintained as intended in the safety analyses.

8. Existing TS 4.5.2.2.a, "Valves," requires that the spray additive valves be tested at intervals not to exceed 1 month. The improved TS SR 3.6.6.16 requires that the spray additive valves be tested

only once every 24 months. This increased testing interval is acceptable, since it is only necessary to verify that the system can actuate on an actual or simulated SI signal on a refueling basis similar to the SI and RHR systems. This SR is best performed during a plant outage, during which the potential for an unplanned transient does not exist. Operating experience has shown that these components usually pass this surveillance when performed at refueling. Therefore, the NRC staff concludes that this is acceptable from a reliability standpoint.

9. Existing TS 4.8.3 surveillance related to the frequency of testing the AFW suction and discharge valves also contained a requirement to test the cross-over motor operated isolation valves. This latter category of valves was not added to improved TS 3.7.5 because these valves are not credited in the safety analyses. The Bases were revised to be consistent with this evaluation. The testing activities related to the suction and discharge valves are contained in the IST Program which provides sufficient control of these testing activities.

The NRC staff reviewed the above less restrictive requirements, and finds them to be acceptable because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with current licensing practices, operating experience, and plant accident and transient analyses, and provide reasonable assurance that the public health and safety will be protected.

3.3.7 Plant Systems

3.3.7.1 Significant Administrative Changes

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed administrative changes to bring the existing technical specifications (TS) into conformance with the improved TS. These changes are as follows:

1. Existing TS 3.3.3.2, "Component Cooling System," defines the actions required if two component cooling water (CCW) trains are inoperable, or if the support piping and valves are inoperable. The improved TS 3.7.7 Condition C contains the same requirements as the existing TS; however, the licensee placed Condition C within the context of the reformatted requirements of the improved TS.

   Normally, with two redundant trains of a system inoperable, or for a loss of function, an orderly shutdown is prescribed. In this case, the CCW cannot support operability of the emergency core cooling system (ECCS) and core spray pumps, and several loss-of-system functions exist. It is not prudent to enter LCO 3.0.3 in this condition, since it would require entry into Mode 5, in which CCW must be available to support the residual heat removal (RHR) heat exchangers. Instead, the new Condition C requires immediate

action to restore operability of one CCW train or the CCW loop header, while placing the plant in Mode 4 within 12 hours. Restricting the cooldown to Mode 4 places the plant in a condition in which the reactor coolant pumps (RCPs) and Auxiliary feedwater (AFW) can be used to provide decay heat removal, while attempts to restore CCW continue. In the event that the RCPs or AFW are also lost, the time required before RHR must be available for decay heat removal increases, as previously stated, by proceeding expeditiously into this lower mode. The NRC staff finds that these changes are the same as the existing TS (although different from NUREG-1431) and are consistent with the actions required for a loss of RHR in improved TS LCO 3.5.3. The NRC staff concludes that it is preferable to establish appropriate TS required actions in advance, rather than directing the licensee to seek immediate enforcement discretion from the NRC staff if all CCW trains are lost.

2. The AFW-related limiting conditions for operations are defined in existing TS 3.4.2.1, "Motor-Driven Auxiliary Feedwater System;" TS 3.4.2.2, "Turbine-Driven Auxiliary Feedwater System;" TS 3.4.2.3, "Standby Auxiliary Feedwater (SAFW) System;" and the surveillance requirements (SRs) of 4.8, "Auxiliary Feedwater Systems." In the improved TS the licensee combined all of these LCOs into the single improved TS LCO 3.7.5. The NRC staff concludes that it is prudent to format these systems together in one LCO because of the interdependencies of the AFW and SAFW trains. These various combinations of AFW and SAFW train inoperabilities were better defined in a single LCO identifying the resulting conditions and the appropriate required actions.

3. The existing TS mentions only the spent fuel pool (SFP) charcoal adsorber system, and not the auxiliary building ventilation system (ABVS). The improved TS has been adapted to the specific subsystem and components assumed operable for only a fuel handling accident in the auxiliary building. This requires that the ABVS associated with the SFP is operable when fuel is being handled or stored in SFP that has decayed less than 60 days since being irradiated.

   The ABVS is defined as the auxiliary building exhaust fan 1C, SFP charcoal adsorbers, and roughing filters. The ABVS is intended to ensure that offsite doses are well within the limits defined in 10 CFR Part 100, in the event of a fuel handling accident. If the ABVS were unavailable, offsite doses would increase, but would remain below 10 CFR Part 100 limits. Therefore, single failures or a loss of offsite power is not a consideration for this LCO.

   The ABVS also provides air cleanup during normal power operation. However, it is unavailable for a loss of offsite power, and it is not considered safety related. There are no air cleanup systems in the various pump and component rooms in the auxiliary building credited in the safety analysis except the SFP charcoal adsorber

system. Therefore, for all radiological accidents other than a fuel handling accident, the ABVS is not credited.

4. By letter dated February 7, 1996, from A. R. Johnson to R. C. Mecredy, the NRC staff issued Amendment 60 which accepted the criticality aspects of the proposed enrichment increase to the Ginna new and spent fuel pool storage racks. Improved TS SRs 3.7.13.1 and 3.7.13.2 require verification prior to fuel movement in the spent fuel pool that the associated fuel assembly meets the necessary requirements for storage in the intended region (e.g., enrichment limit, burnable poisons present). These SRs ensure that the limits accepted in Amendment 60 are met.

The above changes in the statement of requirements in the improved TS are considered purely administrative, and are therefore acceptable.

3.3.7.2 Relocated Requirements

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate or reorganize all or portions of the following existing TS to licensee-controlled documents:

Existing TS	Title
3.11	Fuel Handling in Fuel Building
Table 4.1-2	Minimum Frequencies for Equipment and Sampling Tests
4.8	Auxiliary Feedwater Systems
5.4	Fuel Storage

The more significant changes resulting from these relocated items are as follows:

1. Existing TS 3.11.1 was added to and modified by improved TS 3.7.10, "Auxiliary Building Ventilation System." This LCO defines only the specific ventilation and filtration components within the ABVS (including the SFP charcoal adsorber system) that are required to be operable only for fuel handling accidents. The definition of the specific components required to be operable was relocated to the Bases in accordance with the guidance and structure provided in NUREG-1431.

2. Existing TS 3.11.2, "Fuel Handling in Fuel Building," requires continuous monitoring of radiation levels in the SFP area. The licensee did not add this requirement to the improved TS, because no screening criteria apply since this process variable is not an initial condition of a DBA or transient analysis. Further, the SFP area radiation monitors provide a general alert to SFP radiation release problems. Since a fuel handling accident can only occur as a result of fuel movement, personnel would already be stationed within the auxiliary building and would immediately be aware of a problem. Therefore, the requirement specified for this function does not satisfy the technical specification screening criteria in

the Commission's Final Policy Statement, and is relocated to the TRM.

3. Existing TS 3.11.3 and 3.11.5, "Fuel Handling in Fuel Building," pertain to the heavy load restriction for moving loads over the SFP. The licensee did not add these requirements to the improved TS, because no screening criteria apply since the heavy load limit is not an initial condition of a DBA or transient analysis. The action statements of the existing TS are essentially provided by physical design and current administrative controls. Although these specifications support the maximum refueling accident assumptions, the heavy load restrictions are not process variables monitored and controlled by the operator. Therefore, the requirements specified for these functions do not satisfy the technical specification screening criteria in the Commission's Final Policy Statement, and are relocated to the TRM.

4. Existing TS 3.11.4, "Fuel Handling in Fuel Building," requires that the SFP temperature be limited to 150°F. The licensee did not add this limit to the improved TS, because no screening criteria apply since the SFP water temperature limit is not an initial condition of a DBA or transient analysis. The temperature limit in the existing TS was selected because American Concrete Institute (ACI) Code requirements for nuclear safety-related concrete structures were previously limited to 150°F during all accident conditions. This temperature limit has now been raised to 350°F during accident conditions (see ACI #349-85), which is far above the boiling temperature of the SFP. There is no installed instrumentation for this variable, and it is not controlled by the operator. If boiling were to occur, criticality would be prevented by the storage array in place and by the design of the fuel. Therefore, although the licensee is permitted to continue to rely upon the 150°F value, the requirement specified for this function does not satisfy the technical specification screening criteria in the Commission's Final Policy Statement, and may be relocated to the TRM.

5. The existing TS Table 4.1-2, "Functional Unit #12, Fire Protection Pump and Power Supply," was relocated to the IST Program since it does not meet any of the requirements for inclusion in the ITS. The NRC staff previously approved Amendment 49 for the relocation of all fire protection requirements to licensee-controlled documents. The NRC-approved Fire Protection Program is in the UFSAR. The conforming amendment removed requirements from the TS in four major areas, including: fire detection systems, fire suppression systems, fire barriers, and fire brigade NRC staffing requirements. This is consistent with Generic Letter 88-12 and the guidance provided in NUREG-1431.

6. The existing TS Table 4.1-2, "Functional Unit #18, Secondary Coolant Samples," requires a 72-hour interval frequency for

determining gross specific activity of the secondary system. This requirement is modified by Note 3, which allows up to 6 months between tests, depending on the last activity level. This surveillance was relocated to licensee-controlled plant procedures, since this test gave only early indications of an increase in the secondary coolant specific activity. Since the Dose Equivalent I-131 is now tested monthly (as specified by improved TS SR 3.7.14.1), regardless of the previous results, early indication of changes as provided by the gross activity test is no longer required in the improved TS.

7. Existing TS 4.8, "Auxiliary Feedwater (AFW) Systems," contains various surveillance test requirements and acceptance criteria for inservice testing. The related subsections are TS 4.8.2, 4.8.4, and 4.8.6. In the improved TS, the licensee relocated all component/pump tests and motor-operated valves that are required to be cycled in accordance with ASME Code Section IX to an IST Program referred to in the Administrative Controls section. Therefore, the licensee relocated improved TS SR 3.7.5.2, SR 3.7.5.3, and SR 3.7.5.4, which define details of the AFW and SAFW pump and valve tests. Specifically, these SRs are relocated to the improved TS 5.5.7, consistent with the guidance provided in NUREG-1431 for IST Program requirements.

8. Existing TS 5.4.3 describes the fuel storage design feature denoting the 60-day limit on storage of discharged fuel assemblies in Region 2. The licensee did not add this limitation to the improved TS, because no screening criteria apply for the time limit on storage of discharged fuel assemblies in Region 2. The current 60-day limit was established to provide a sufficient margin in SFP temperature calculations as a result of decay heat loads in Region 2 from discharged fuel assemblies. Although the SFP cooling system and the associated restriction on heat load prevent structural integrity damage to the SFP, these limits are not assumed to mitigate the consequences of a DBA. The restriction on heat load is neither used for, nor capable of, detecting a significant abnormal degradation of the reactor coolant pressure boundary before a DBA. The restriction on heat load is a non-significant risk contributor to core damage frequency and offsite doses. Since the NRC Final Policy Statement technical specification screening criteria do not apply, the NRC staff finds that this requirement is acceptably relocated to the TRM.

9. The licensee changed existing TS 4.8.1, 4.8.2, 4.8.3, 4.8.4 and 4.8.5 requirements for the AFW pump test surveillance frequencies from monthly to as defined in the Inservice Testing Program (SRs 3.7.5.2, 3.7.5.3, and 3.7.5.4) consistent with ASME Section XI requirements. In addition the acceptance criteria were also relocated to the Inservice Testing Program consistent with NUREG-1431. The reference to the industry frequency for testing and the program acceptance criteria together provide sufficient control for

future testing activities, because the testing includes comparing the reference differential pressure and flow of each AFW pump with the last recorded value and evaluating the data for trends that might be indicative of incipient pump failure. Additionally, the test frequencies are based on accepted industry practice.

The above relocated requirements related to plant systems are not required to be in the TS under 10 CFR 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. Further, they do not fall within any of the four criteria set forth in the Commission's Final Policy Statement, as discussed in the Introduction above. In addition, the NRC staff finds that sufficient regulatory controls exist under 10 CFR 50.59. Accordingly, the NRC staff concludes that these requirements may be relocated from the TS to the licensee's TS Bases, UFSAR, TRM, or plant procedures, as applicable.

3.3.7.3 More Restrictive Requirements

By electing to implement the Section 3.7 Specification of NUREG-1431, the licensee adopted a number conditions that are more restrictive than those required by the existing TS. The more significant conditions are as follows:

1. Existing TS 3.1.4.1, "Maximum Coolant Activity," requires TS compliance whenever the reactor is critical or RCS temperature is greater that 500°F. Improved TS 3.7.14 extends this mode applicability to be met in Modes 1, 2, 3, and 4. This change ensures that the secondary coolant activity limit is in effect for a longer period than allowed by the current Ginna TS operational requirements. Also, should any secondary system leakage occur, this change further minimizes the potential for any resulting offsite dose consequences. The NRC staff finds that this change enhances the safety of operations by extending TS requirements and controls.

2. Existing TS 3.1.4.4, "Maximum Coolant Activity," requires that the reactor be placed in hot shutdown in 8 hours, and in cold shutdown within 40 hours. The improved TS 3.7.14 Condition A specifies that the reactor must be in Mode 3 in 6 hours, and Mode 5 within 36 hours. This change shortens the time during which the reactor is rendered subcritical and cooled down; however, the time period is consistent with all other improved TS times allowed for an orderly plant shutdown. The shortened time period selected was provided in the NUREG-1431 guidance document as consistent with the operating history and experience with plants of this design. The NRC staff finds that maintaining consistent operational requirements throughout the improved TS provides normal guidelines and consistent reliance on the same procedural actions for all shutdown operations.

3. Existing TS 3.3.3.1.b, "Component Cooling System," only requires that the pumps, heat exchangers, and various valves must be

operable. Improved TS 3.7.7 expands the definition of "operable" to include the CCW loop header. The CCW loop header is defined as the section of piping from the discharge of the pumps to the first isolation valve of each CCW-supplied component. The loop header then continues from the last isolation valve on the discharge of the supplied component to the suction of the pumps. Also, requiring the CCW loop header to be operable provides a clear and concise LCO requirement for operators since portions of the loop header design can be defeated by inadvertent valve closure. The NRC staff finds that it is important to periodically and explicitly verify and determine that the CCW loop header remains operable, and that this change enhances the safety of plant operations.

4. Existing TS 3.3.4.1, "Service Water (SW) System," does not define the six sets of isolation valves separating the non-safety and safety-related heat loads from the SW loop header. Improved TS 3.7.8 further defines these isolation valves as the outer boundary of the SW loop header. If a failure affects only one or two loads supplied by SW, and it does not affect any other supplied loads, the SW system does not have to be declared inoperable. Instead, the affected loads are declared inoperable and the isolation valve sets to the affected loads are closed. The LCO covering the affected inoperable heat load is entered because closure of the isolation valve does not affect the operability of the remaining portion of the SW loop header. The improved TS clarify the appropriate required actions for the SW system LCO conditions. In addition, the licensee added a new SR 3.7.8.3 to verify that the cross-tie valves remain open for this common SW loop header. The NRC staff finds that these new clarifications, measures, and verifications of plant components collectively enhance the conditions established to ensure continued safe operation of the SW system.

5. The existing TS do not contain any requirements for the operating limits of the ultimate heat sink, which is Lake Ontario. The licensee revised improved TS 3.7.8 to add a new SR 3.7.8.1, which verifies that the screen house bay water level and temperature are within limits every 24 hours. The ability of water to enter the SW intake structure and the water level for the SW pumps suction are to be regularly verified as operable. The cooling capacity of the SW system is dependent upon the lake temperature for both winter and summer operation. This will now be verified. These new SRs will further ensure that the parameters for correct operation of the SW system will be met. The NRC staff finds that this will enhance the safety of operations at the Ginna plant.

6. Existing TS 3.3.5.1, "Control Room Emergency Air Treatment System (CREATS)," requires that this system be operable only when the RCS is equal to or greater than 350°F. The applicability in improved TS 3.7.9 was revised to require that CREATS be operable in Modes 1 through 6 and during movement of irradiated fuel assemblies.

Additionally, existing TS 3.5.6 requires that the control room HVAC detection system (i.e., chlorine, ammonia, and radioactivity monitors) be operable at all times, instead of only being operable above 350°F like CREATS. The filtration system is designed to ensure that dose rates to operators are within the guidelines of GDC 19 in the event of an accident. While dose rates to operators are expected to be lower when the RCS is less than 350°F, no current analyses exist under these conditions. In addition, failures of the waste gas decay tanks can still occur below 350°F, and also require control room isolation. Therefore, the NRC staff finds that this change corrects the existing mode of applicability to provide consistency within the specifications and the accident analyses.

7. Existing TS 3.3.5.1, "Control Room Emergency Air Treatment System (CREATS)," requires that this system be operable, but does not define the system. In the improved TS, the licensee defines CREATS as comprising two subsystems, namely the CREATS filtration train and the isolation damper trains. As such, the licensee revised the improved TS 3.7.9 to provide requirements for an inoperable filtration train and inoperable dampers. The CREATS dampers isolate the control room in the event of a radiological event, while the filtration train filters the control room atmosphere following isolation.

   The new Condition A continues to allow the filtration train to be inoperable for 48 hours before requiring a shutdown or placing the control room in the emergency radiation mode (i.e., CREATS Mode F). In new Condition B, if one of the two redundant dampers in each outside air flow path is inoperable, the new specifications allow 7 days to restore the damper to operable status similar to restoring one redundant train using the guidance provided in NUREG-1431. If both dampers are inoperable, per new Condition E, the plant must enter LCO 3.0.3 since the control room can no longer be isolated. If both dampers are lost in Modes 5 or 6, or during fuel movement, per new Condition F, fuel movement and CORE ALTERATIONS must be suspended immediately. These changes define inoperable conditions that currently do not exist in the Ginna TS. Therefore, the NRC staff finds that these new required actions accurately provide consistency with the design assumptions used in the accident analyses.

8. Existing TS 3.3.5.2, "Control Room Emergency Air Treatment System (CREATS)," requires that if CREATS is inoperable, the reactor shall be placed in hot shutdown in 6 hours, and the RCS temperature must be less than 350°F in an additional 12 hours. The improved TS Condition C requires further cooldown to Mode 5 within 36 hours. This is more restrictive, but also implements the guidance of NUREG-1431 since whenever a loss of function occurs in a system, an orderly shutdown of the reactor is required to exit the associated Mode of Applicability. The NRC staff finds that this uniform

approach to system inoperability provides for enhanced measures and ensures safer operations at the plant.

9. Existing TS 3.4.1, "Main Steam Safety Valves (MSSVs)," allows the MSSVs to be tested anytime the RCS temperature is above 350°F. The licensee proposed improved TS 3.7.1 specifically to require that all MSSVs be tested before entering Mode 2, rather than accepting the current ambiguous wording and to provide specific values for the valve setpoints. This change is consistent with current operating practices. It allows the MSSVs to be tested under hot conditions, ensuring that the MSSVs are operable just before the reactor goes critical. Any test of a valve performed while closest to its normal operating conditions lends more confidence that the valve will function correctly if called upon under its designed accident scenario. The NRC staff concludes that these changes ensure the assumptions of the safety analyses will be met.

10. Improved TS 3.7.5, "Auxiliary Feedwater System," has Condition D, which was not in the existing TS. Condition D states that, if all AFW trains and flow paths to one or more steam generators are inoperable, Required Actions allow 4 hours to restore at least one train to each affected steam generator. A time limit for being in this configuration is necessary, since no AFW would be available in the event of a high energy line break affecting the only remaining steam generator able to receive the preferred cooling water from the AFW system. If the repairs for this Condition D are not completed, then entry into Mode 4 is required. However, if both AFW and SAFW are inoperable all plant shutdowns are stopped until at least one train of AFW or SAFW is restored to operable status before proceeding to a controlled cooldown. Requiring an immediate cooldown in this configuration is not considered prudent since AFW or SAFW would be unavailable for providing the decay heat removal needed in lower modes. These changes are consistent with the Required Actions for loss of CCW in LCO 3.7.7, which prevents proceeding to a cooldown without adequate decay heat removal capability.

11. Existing TS 3.4.2.3, "Standby Auxiliary Feedwater (SAFW) System," requires an operable flow path from each standby AFW pump to "its respective" steam generator. The improved TS corrected an error in the existing TS by requiring flow to "both" steam generators through the cross-tie motor-operated valves. The existing TS 4.8.5 required these normally-closed valves to be cycled once every month. These cross-tie valves are normally closed to maintain train independence. They are also maintained in the closed position to prevent a passive failure in either standby auxiliary feedwater train from failing both trains. For example, with the valves closed, a major piping leak in the cross-over header would diminish the SAFW train flow only to its respective steam generator on the leaking side The accident analyses reported in the UFSAR credited these cross-tie valves. Therefore, the improved TS SR

3.7.5.4 requires the flow path to be open and the periodic verification that these valves will open to perform this cross-tie function to both steam generators. The NRC staff finds that these added measures, inspections, and verifications enhance the reliability of the SAFW train cross-tie link to both steam generators, and thus improve the overall safety of operations at the plant.

12. Existing TS 3.11.1.c, "Fuel Handling in Fuel Building," requires all doors, windows, and other direct openings between the operating floor area and the outside to be closed. The improved TS 3.7.10 changed these requirements to require a negative pressure within the auxiliary building operating floor with respect to the outside environment. This change provides consistency with assumptions concerning the fuel handling accident as described in the Bases. In addition, the licensee added improved TS SR 3.7.10.2 to verify that the ABVS can maintain a negative pressure with respect to atmospheric conditions at the auxiliary building operating floor level. The NRC staff finds that this change provides an LCO based on design and operation of the system, as approved by the NRC staff for accident mitigation. In addition, the enhanced presentation is much clearer, making it easier for licensee personnel to implement without adding any additional requirements.

13. In the improved TS, the licensee added a new SR 3.7.11.1, which requires verification every 7 days that at least 23 feet of water is available above the top of the irradiated fuel assemblies seated in the storage racks during fuel movement in the SFP. This verification, which was not in the existing TS, is required since the fuel handling accident assumes that at least 23 feet of water is available to provide protection against exceeding the offsite dose limits with respect to iodine releases. The NRC staff finds this acceptable, based on operating experience, because the volume of the pool is normally stable and any changes are strictly controlled by plant procedure.

14. The licensee proposed to adopt SR 3.7.8.3 in the improved TS. This surveillance requires the verification every 31 days that all SW loop header cross-tie valves are either locked open or locked closed, as necessary, to support the safety analyses. The NRC staff finds this acceptable.

15. The improved TS SR 3.7.13.2 requires verification by administrative means, before fuel movement in the SFP, that the associated fuel assembly meets the necessary requirements for storage in the intended region. The initial enrichment limit and burnup of the fuel assembly must be in accordance with LCO Figure 3.7.13-1 or the LCO requirements. The NRC staff finds that this verification provides the most direct method to prevent or limit the amount of time that a fuel assembly could be misloaded in either region of the SFP.

16. In the improved TS 3.7.6, the licensee added a new SR 3.7.6.1, which requires verification every 12 hours that the condensate storage tank (CST) volume is at least 22,500 gallons. The existing TS 3.4.3.a.1 requires this volume, but the existing TS do not mandate a corresponding surveillance. The 12-hour interval is based on operating experience and the need for operator awareness of changing plant conditions. The NRC staff also determined that there are other control room indications of a deviation in the CST level. Collectively, these surveillances and instrument checks ensure that the minimum condensate volume will be available for the preferred AFW system should an accident occur as assumed in the safety analyses.

17. In the improved TS 3.7.7, "Component Cooling Water (CCW) System," the licensee added a new SR 3.7.7.1, which requires verification every 31 days that each CCW manual and power-operated valve in the CCW pump train or loop header flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position. The existing TS did not require this surveillance. The NRC staff finds that these increased control and inspection steps enhance reliable operation to ensure that the CCW system is capable of performing its function to provide cooling water to safety-related components following a DBA.

18. In the improved TS 3.7.7, "Component Cooling Water (CCW) System," the licensee added SR 3.7.7.2, which requires performance of a complete cycle of each CCW motor-operated isolation valve to the RHR heat exchangers, in accordance with the IST Program. The non-essential CCW automatic valves are tested by improved TS LCO 3.6.3. All CCW heat loads required following an accident relate only to cooling for the SI, CS, and RHR pumps, as well as the RHR heat exchangers. CCW flow is continuously maintained through the pump loads, while the RHR heat exchangers are isolated by the two motor operated isolation valves verified in this SR 3.7.7.2. The NRC staff finds that this verification ensures that the normally closed motor-operated valves are capable of being opened when required following the postulated DBA.

19. In the improved TS 3.7.8, "Service Water (SW) System," the licensee added SR 3.7.8.1, which requires verification every 31 days that each SW manual and power- operated valve in the SW pump train or loop header flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position. The existing TS did not require this surveillance. The NRC staff finds that these increased control and inspection steps enhance reliable operation to ensure that the SW system is capable of performing its function to provide cooling water to safety-related components following a DBA.

20. Existing TS 4.7, "Main Steam Isolation Valves (MSIVs)," covers only testing requirements, and does not have a corresponding LCO for

MSIVs. The licensee revised existing TS 4.7 to add a new LCO for MSIVs and for the "non-return check valves." In the improved TS 3.7.2 LCO, the applicability, conditions and required actions are consistent with the existing TS. In existing TS Table 3.5-2, operability required MSIV "open above 350°F T_{avg};" however, this requirement pertains only to the instrumentation (not to the actual MSIVs). Hence, the licensee modified the applicability to include operability of the MSIVs during Modes 1, 2, and 3, except when all MSIVs are closed and deactivated.

The licensee also added new conditions and required actions based upon the remaining number of operable flow paths from each steam generator to address the condition in which an MSIV or a non-return check valve or both were inoperable. SR 3.7.2.1 and SR 3.7.2.2 verify that each MSIV and non-return check valve can close in accordance with the IST Program. SR 3.7.2.3 verifies that each MSIV can close on an actual signal using the manual controls in the control room during refueling.

The NRC staff finds that these additional controls and testing requirements ensure that these valves are verified to be operable and functional as currently assumed in the safety analyses.

21. Existing TS 4.8, "Auxiliary Feedwater Systems," does not contain any requirements for verifying the operability of the flow paths from the AFW and SAFW pumps to the steam generators. Consequently, the licensee added improved TS SR 3.7.5.1, requiring verification every 31 days of the correct position of each AFW and SAFW manual, power-operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position. This verification is required to ensure that the AFW and SAFW systems are operable when not in service. The NRC staff finds that these added measures and checks enhance the certainty that these safety systems will be properly aligned in order to function as assumed in the safety analyses.

22. The existing TS do not contain an LCO for the main feedwater and isolation valves, main feedwater regulation valves, and their associated bypass valves, as stated in NUREG-1431. Consequently, the licensee agreed to add new LCO 3.7.3 to the improved TS. At Ginna, these isolation valves are currently identified in plant procedures as the main feedwater regulation valves and associated bypass valves, and the main feedwater pump discharge valves. The two new surveillance requirements (SR 3.7.3.1 and SR 3.7.3.2) specify an isolation time of 80 seconds for the main feedwater pump discharge valves, and 10 seconds for the remaining valves, when tested in accordance with the IST Program. The LCO requires these valves to be operable above Mode 4 to provide isolation capability, except when both steam generators are isolated from both feedwater pumps. The NRC staff finds that these additional controls and testing requirements ensure that these valves are verified to be

operable and functional, as currently assumed in the safety analyses.

23. The existing TS do not contain an LCO for the atmospheric dump valves as stated in NUREG-1431. Consequently, the licensee has added new LCO 3.7.4 to the improved TS. At Ginna, these isolation valves are currently identified in plant procedures as the atmospheric relief valves (ARVs). The LCO requires that the ARVs be operable when the average RCS temperature is greater than 500°F in Mode 3 to provide cooldown capability following a steam generator tube rupture event, as assumed in the accident analyses. Consequently, the licensee added surveillance requirements SR 3.7.4.1 and SR 3.7.4.2 to verify once every 24 months that each ARV and its block valve are capable of opening and closing. The NRC staff finds that these additional controls and testing requirements ensure that these valves are verified to be operable and functional, as currently assumed in the safety analyses.

24. The licensee proposed to adopt LCO 3.7.12 for spent fuel pool boron concentration limits in the improved TS. This LCO requires verification every 31 days that the spent fuel pool boron concentration limits are met. In addition, the LCO specifies remedial actions for conditions when the boron concentration limits are not met. The NRC staff finds that these provisions further enhance plant safety.

The NRC staff has reviewed these more restrictive requirements, and concludes that they enhance the existing TS. Therefore, these more restrictive requirements are acceptable.

3.3.7.4 Less Restrictive Requirements

In electing to implement the Section 3.7 specifications of NUREG-1431, the licensee proposed a number of conditions that are less restrictive than those allowed by the existing TS. The more significant conditions are as follows:

1. The existing TS 3.3.3.1 is revised to allow one component cooling water (CCW) heat exchanger to be removed from service for up to 31 days. The CCW heat exchangers are each 100% of the rated capacity for component cooling and they are separated from the CCW pump trains by a section of common piping. Since there is no single active failure which can result in a failure of the redundant heat exchangers, the 31-day allowed outage time is considered acceptable. In addition, the CCW heat exchangers are passive devices such that any failure of a heat exchanger is bounded by a failure of the CCW piping in the loop header.

2. Existing TS 3.3.3.2.b, "Component Cooling Water (CCW) System," allows 24 hours to restore operability if one of two component cooling heat exchangers or any passive CCW component is inoperable, provided that 100% heat exchanger capacity is still available. The

licensee did not include this requirement in the LCO, however, because this unique condition is already a subset of the conditions for improved TS LCO 3.7.7. One 100% capacity heat exchanger is always operating; the second heat exchanger is operable, but may be only partially in-service since it is not relied upon by the safety analyses. If any other passive component is inoperable, improved TS 3.7.7 Conditions A and D define the appropriate required actions if one or two CCW trains are made inoperable by the inoperable passive component. The NRC staff finds that this existing TS requirement has been replaced by more specific conditions and required actions than are contained in the existing TS.

3. Existing TS 3.3.3.2.1.a, "Component Cooling Water (CCW) System," permits one component cooling pump to be inoperable for 24 hours before requiring reactor cooldown. By contrast, improved TS 3.7.7 Condition A allows 72 hours to restore a CCW pump train to operable status before requiring an orderly plant shutdown. This change allows an additional 48 hours at power to complete repairs before shutting down. The existing TS previously required placing the reactor in hot shutdown before allowing the same additional 48 hours to restore the pump train. The improved TS maintains the same total allowed outage time and assumptions as the existing TS, but it forestalls any mode changes until the expiration of the Condition A Completion Time. The guidance in NUREG-1431 provides 72 hours to restore one train to operable status on systems with redundant trains. The NRC staff finds the new TS consistent with the current TS requirements for safety-related functions supported by the CCW system (RHR, SI, and CS systems) all of which allow 72 hours to restore one inoperable train.

4. Existing TS 3.3.4.2, "Service Water (SW) System," does not contain any allowed outage conditions for one service water pump or SW train to be inoperable. By contrast, improved TS 3.7.8 adds a new Condition A, which allows 72 hours to restore a SW pump or a SW train to operable status before requiring an orderly plant shutdown. The guidance in NUREG-1431 allows 72 hours to restore one train to operable status on systems (such as the SW system) that have redundant trains. Since the SW trains are 100% redundant, removing one of two trains affects redundancy but does not place the plant outside the accident analyses. Since NRC staff guidance for other safety system functions allows one train to be inoperable for 72 hours (e.g., ECCS trains), the NRC staff finds that this change is consistent within the improved TS. During the time allowed to restore a redundant SW train, a 100% capability SW system would not be capable of taking an additional assumed single failure. Further, the NRC staff finds it highly improbable that an accident would occur within this short window of time that would require the operability of a redundant SW train.

5. Existing TS 3.3.4.2, "Service Water (SW) System," does not contain any allowed outage conditions for two service water trains or the

SW loop header to be inoperable. By contrast, the improved TS 3.7.8 adds a new Condition C in which LCO 3.0.3 is entered for this loss of function; however, a Note associated with this Required Action C.1 states that LCO 3.7.7 must also be entered. This places the LCO 3.0.3 shutdown in suspension until the CCW system supported by the SW system has one CCW train restored to operable status. In this condition, immediate action must be initiated to restore one SW pump or the SW loop header to operable status; however, it is not prudent to exit the mode of applicability, since the SW system (which supports the CCW and other systems) is required in Mode 5 for decay heat removal. Instead, Required Actions D.2 and D.3 of improved TS 3.7.7 require a cooldown to Mode 4, in which AFW provides for decay heat removal. If AFW were lost, additional response time would be achieved by being in the lower modes before RHR, and consequently SW would be required. These changes are consistent with the required actions for loss of CCW. The NRC staff concludes that it is preferable to establish appropriate TS with required actions in advance, rather than directing the licensee to seek immediate enforcement discretion from the NRC staff if all SW trains are lost.

6. The Ginna safety analyses treat the auxiliary feedwater (AFW) system as composed of four separate trains, with all four trains initially required to be operable. According to the existing TS 3.4.2.1.b, "Motor-Driven Auxiliary Feedwater System," when three out of four trains are inoperable, the inoperable pumps must be restored to operable status within 24 hours. The existing TS does not contain a requirement for when two out of four trains become inoperable (such as two inoperable motor-driven auxiliary feedwater pumps with an operable turbine-driven AFW pump, and the two associated flow paths remaining). The improved TS adds this new condition and the required actions to be similar to existing TS 3.4.2.2.a. (This existing TS concerns the same instance in which two out of four AFW trains remain operable; and requires that the inoperable pump(s) be restored to operable status within 72 hours rather than 24 hours). The licensee therefore adopted improved TS 3.7.5 Condition C, to allow both motor-driven AFW pumps to be inoperable for up to 72 hours, since the turbine-driven train is allowed to be inoperable for up to 72 hours per TS 3.4.2.2.a and the safety function of these two trains are equivalent. In addition, the licensee added to Condition C the two-out-of-four condition when one turbine-driven AFW train flow path and one motor-driven AFW train are inoperable to opposite steam generators. As noted above, the licensee made these changes because the accident analyses treat the preferred AFW system as four trains (i.e., two motor-driven trains and two turbine-driven trains), such that each steam generator receives flow from two AFW trains. Therefore, the failure of both motor-driven trains or the turbine-driven train (or both flow paths) has the same consequence (i.e., loss of one train to each steam generator). This change completes the full identification of all potential successive degraded AFW

train conditions, and specifies the appropriate required actions to respond to each circumstance. The NRC staff finds that allowing this extended outage time is acceptable in that it does not affect any of the design assumptions of the accident analyses.

7. Existing TS 3.4.3, "Sources of Auxiliary Feedwater," Action a.2, requires that the licensee demonstrate the operability of the SW system as a water source if the condensate storage tank is inoperable. The improved TS 3.7.6 Condition A provides a new required action, requiring only a verification that a backup source of auxiliary feedwater is available (rather than testing the new source). This verification must be completed in 4 hours, which is shorter than the time to test the SW flow paths but it is more flexible with respect to number of sources available. In other words, Required Action A.1 permits sources other than the SW system to be available as a backup source. (These backup sources are identified in the Bases). This change implements the guidance of NUREG-1431 and provides a clear and concise set of requirements to plant operators. The NRC staff finds that the identification of multiple sources of backup water supplies is acceptable and provides additional operational flexibility.

8. In the existing TS Table 4.1-2, "Functional Unit #17," requires a monthly verification of the SFP boron concentration limits. The improved TS 3.7.12 revises this requirement, stating that it must be performed once every 31 days when "fuel is stored in the SFP and the position of fuel assemblies which were moved in the SFP have not been verified." The current monthly requirement (regardless of the status of the SFP verification) is not reflected in the fuel handling accident analysis, which does not credit the availability of soluble boron. The NRC staff finds this to be acceptable since once the fuel assemblies have been verified to be in the correct position, the accident analyses no longer credit the availability of boron in the pool.

9. The existing TS Table 4.1-2, "Functional Unit #18, Secondary Coolant Samples," requires that gross specific activity of the secondary system be determined every 72 hours. However, the licensee deleted this TS requirement from the improved TS. In addition, Note 3 to the existing TS Table 4.1-2 required an isotopic analysis for I-131 equivalent activity at least monthly, but it allowed up to 6 months between tests depending upon the last activity level. By contrast, improved TS SR 3.7.14.1 requires the specific activity of the secondary system to be determined for Dose Equivalent I-131 once every 31 days, independent of the last activity level. These changes are all consistent with NUREG-1431, with regard to confirming the validity of the safety analysis assumptions concerning the source terms in post-accident releases. The NRC staff finds that the deleted TS requirement and the regular SR frequency permit adequate time to detect any increasing trend in

the Dose Equivalent I-131, and also allows time to take appropriate action to maintain levels below the LCO limit.

10. Existing TS 4.5.2.3.9, "Air Filtration System for the Control Room Emergency Air Treatment System (CREATS)," is included in the improved TS SR 3.7.9.1 and SR 3.7.9.3. The licensee also retained the requirement to operate the system at least 15 minutes each month (SR 3.7.9.1). In addition, the requirement to test the automatic actuation capability of CREATS once per month appears in improved TS 3.7.9.3, but the licensee changed the surveillance frequency to once during each refueling outage. The licensee also retained the requirements to measure filter efficiency and to replace components after certain maintenance operations (improved TS SR 3.7.9.2, under the Ventilation Filter Test Program). These surveillances collectively ensure the reliability of the CREATS to perform its intended safety function, which is now the same as the guidance provided in NUREG-1431. The NRC staff finds that the change to the longer test interval is consistent with Regulatory Guide 1.52, Revision 2, as discussed in Section 4.0 of this SE.

11. Existing TS 4.11.1.1.d, "Spent Fuel Pit Charcoal Adsorber System," requires that flow shall be maintained through the system using either the filter or bypass filter flow path for at least 15 minutes each month. However, the licensee deleted this requirement for monthly inspections because of the administrative and plant-specific changes made in developing the improved TS LCO 3.7.10 for the ABVS. This improved TS requires the ABVS to be operable and in operation during its mode of applicability. Since the SFP charcoal adsorber system is a subsystem of this ABVS, it is also in continuous operation. The LCO applicability also requires operability to be verified just before fuel movement. Hence, the need to verify monthly that the system can operate is an additional unwarranted constraint, since the portions of the system are in continuous operation. The NRC staff concludes that the improved TS SR 3.7.10.2 requirement to verify that the ABVS can maintain a negative pressure on the operating floor of the SFP, is a more direct verification than existing TS requirements. Therefore, the NRC staff finds that this change directly verifies whether the assumptions are met for the fuel handling accident safety analyses.

The NRC staff has reviewed the above less restrictive requirements and finds them to be acceptable, because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with current licensing practices, operating experience, and plant accident and transient analyses, and provide reasonable assurance that the public health and safety will be protected.

3.3.8 Electrical Power Systems

3.3.8.1 Significant Administrative Changes

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed administrative changes to bring the existing TS into conformance with NUREG-1431 improved TS. The more significant changes resulting from the administrative items are as follows:

1. Existing TS 3.7.1.1.a requires one operable independent offsite power source for cold shutdown or refueling. While the offsite source is not specified, power backfed through unit auxiliary transformer 11 is specifically permitted as an alternative in the UFSAR. Improved TS 3.8.2 rewords and embodies this requirement. Additionally, the basis for improved TS 3.8.2 defines an operable qualified offsite circuit. Power from either offsite circuit 751 or 767 or backfeeding through auxiliary transformer 11 satisfies the requirement for one operable independent offsite power source during cold shutdown or refueling. This is an acceptable administrative change.

2. Existing TS 3.7.1.1 contains the electrical power requirements in cold shutdown and refueling (Modes 5 and 6). Existing TS 4.6.1.a and 4.6.2, 4.6.3, and 4.6.4 contain the associated surveillance requirements in these Modes. These requirements are now in improved TS 3.8.2, 3.8.3, 3.8.4, 3.8.5, 3.8.6, 3.8.8 and 3.8.9.

   Existing TS 3.7.2.1 contains the electrical power requirements above cold shutdown (Modes 1, 2, 3, and 4). Existing TS 4.6.1.6, 4.6.1.c, 4.6.1.d, 4.6.2, 4.6.3, and 4.6.4 contain the associated surveillance requirements in these Modes. These requirements are now in improved TS 3.8.1, 3.8.3, 3.8.4, 3.8.6, 3.8.7, and 3.8.9. The non-administrative changes associated with these existing TS are discussed in the sections that follow.

   Both existing TS 4.6.1.b.2 and improved TS SR 3.8.3.1 require a 40-hour supply of diesel fuel oil. LCO 3.8.3 requires an onsite supply of at least 5,000 gallons of fuel (SR 3.8.3.1) for the diesel generator required to be operable by LCO 3.8.2. The improved TS have a Completion Time of 12 hours for LCO 3.8.3, Action A.1, to ensure that fuel oil can be delivered in a timely manner. This 12-hour Completion Time to restore a 40-hour supply is a ratio roughly equivalent to the NUREG-1431 requirement specifying a Completion Time of 48 hours to restore a 7-day supply and preserve the current licensing basis. As such, this 12-hour Completion Time is acceptable. Combined, these improved TS LCOs are essentially equivalent to the existing TS requirements, and these administrative changes are acceptable.

3. Existing TS 3.7.2.1.a.3 requires two operable diesel generators with an onsite supply of 5,000 gallons of fuel for each diesel

generator before and whenever exceeding cold shutdown. Improved TS 3.8.1.b and 3.8.3 (SR 3.8.3.1) contain these requirements for Modes 1, 2, 3, and 4.

Existing TS 3.7.1.1.c requires an operable diesel generator for cold shutdown or refueling. It also requires an onsite supply of 5,000 gallons of fuel for the diesel generator, as well as operability of the associated 480-Vac distribution system buses. Improved TS 3.8.2 requires one emergency diesel generator capable of supplying the 480-Vac Class 1E buses required by improved TS 3.8.10. LCO 3.8.10 requires portions of the electrical distribution system needed to support operability of systems, equipment and components that are required to be operable by other LCOs to be energized. Existing TS 4.6.1.b.2 verifies (at least once every 31 days when not in cold shutdown or refueling) that each diesel generator has a minimum of 5,000 gallons of fuel oil stored onsite. Improved TS SR 3.8.3.1, requires verification of an onsite supply of fuel oil of at least 5,000 gallons for each diesel generator in Modes 1, 2, 3, and 4, and for the diesel generator required to be operable in Modes 5 and 6. It also ensures that the diesel generators are operable when required.

4. Should loss of the specified power sources occur during cold shutdown or refueling, existing TS 3.7.1.2 requires the immediate suspension of operations involving positive reactivity changes and core alterations, as well as initiation of corrective actions to restore the power sources to operable status. Improved TS 3.8.10, Condition A, provides the same actions (in the NUREG-1431 format) for the distribution systems while in cold shutdown or refueling. Likewise, improved TS 3.8.2, Conditions A and B, provide the same actions for the offsite power sources and diesel generators, respectively, during cold shutdown or refueling. Improved TS 3.8.5, Condition A, provides the same actions for loss of battery or battery charger during cold shutdown or refueling. Improved TS 3.8.8, Condition A, provides the same actions for the AC instrument bus sources during cold shutdown or refueling. However, an alternative to all of these improved TS required actions is to declare the associated supported equipment inoperable and enter their required actions. This provides an equivalent level of control and therefore, these administrative changes are acceptable.

5. Existing TS 3.7.2.1.a.1 requires one operable independent offsite power source before and whenever exceeding cold shutdown. Improved TS 3.8.1.a embodies and embellishes this specification by requiring one qualified independent offsite power source connected between the offsite transmission network and each of the onsite 480-Vac safeguards buses. The LCO, conditions, and associated Bases reflect only one required operable offsite circuit for each 480-Vac safeguards bus. Existing TS 3.7.2.1.a.2 requires energizing the 480-Vac safeguards buses before and whenever exceeding cold shutdown. This requirement specifically affects Train A, buses 14

and 18, and Train B, buses 16 and 17. Improved TS 3.8.9.a requires the ac power distribution system to be operable in Modes 1, 2, 3, and 4, encompassing this requirement. The offsite distribution system at Ginna is designed to provide power to the 480-Vac safeguards buses from either or both of the station's auxiliary transformers. The current licensing basis allows indefinite operation in either configuration, providing for a total of three ac sources (one offsite and two diesel generators). The number of required sources and the associated actions and completion times are consistent with the current Ginna licensing basis. The associated conditions reflect a total of three ac sources. For any combination of required ac power sources inoperable during any single event that results in failure to meet LCO 3.8.1, the TS requires entry into LCO 3.0.3. These administrative changes are acceptable.

6. Existing TS 3.7.2.1.a.6 and 3.7.2.1.a.7 require ac instrument buses 1A and 1C, and 1B, respectively, to be operable before and whenever exceeding cold shutdown, and powered from their associated inverters and constant voltage transformer from MCC 1C, respectively. Improved TS 3.8.9 requires the ac instrument bus power subsystem to be operable in Modes 1, 2, 3, and 4. In addition, improved TS 3.8.7 requires the same inverters (for instrument buses A and C) and constant voltage transformer (for instrument bus B). Together, these improved TS LCOs embody the existing TS requirements.

   The improved TS Bases for SR 3.8.9.1 and SR 3.8.10.1 list the requirements for the ac instrument bus power distribution subsystem as "between 113 V and 123 V." The "required voltage for the Twinco panels supplied by the 120 V instrument buses is between 115.6 V and 120.4 V," which is more restrictive than the limits on the instrument bus voltage. The instrument buses supply power to the Twinco panels, which in turn supply the safety-related instrument loops. Both the Twinco panels and the instrument buses were purchased and installed with a voltage tolerance of ± 2%. Because of instrument sensitivity concerns related to the loads supplied by the Twinco panels, these panels are limited to ± 2% of 118 V. These administrative changes are acceptable.

7. Existing TS 3.7.2.2.b.2 requires a reduction to hot shutdown or below within 6 hours, and cold shutdown within the following 30 hours if the surveillance and restoration for an inoperable diesel generator is not completed as required. If the action and completion times for Condition A (no offsite power to one or more 480-Vac safeguards buses), Condition B (one diesel generator inoperable), or Condition C (no offsite power to one or more 480-Vac safeguards buses and one diesel generator inoperable) are not met, improved TS 3.8.1, Condition D, requires the reactor to be in Mode 3 within 6 hours, and Mode 5 in 36 hours. These administrative changes are equivalent and acceptable.

8. Existing TS 4.6.1.c requires the diesel operability tests required in Specification 4.6.1.b to be performed within 31 days before exceeding cold shutdown. The requirement in Specification 4.6.1.b to perform the tests before exceeding cold shutdown is replaced with a general provision (improved TS SR 3.0.4) restricting entry into a mode or other specified condition in the applicability of an LCO unless the LCO's surveillances are met. As a general provision to the TS, this requirement encompasses the existing TS requirements, and is therefore acceptable.

9. The existing TS 18-month interval for diesel generator load rejection testing (4.6.1.e.2) and diesel generator simulated loss of power with concurrent safety injection testing (4.6.1.e.3) is changed to a frequency of 24 months in the improved TS. The licensee reviewed records related to performance of the diesel generator load rejection testing (existing TS 4.6.1.e.2). No failures were observed since this test was first performed in 1969. While this test has historically been performed on an annual basis (because of 12-month refueling cycles), the licensee found no historical information that would refute an increased surveillance interval of 24 months. If diesel generator load rejection performance declines following the change to 24 months, the necessary actions would be implemented via the performance-based diesel generator maintenance program or via implementation of the Maintenance Rule, required by June 1996.

   The licensee reviewed the records for the diesel generator loss of power with concurrent safety injection test (existing TS 4.6.1.e.3). These tests are currently conducted annually, with only two relay failures observed during the past 11 years. Neither reported failure would prevent the associated diesel generator from performing its safety-related function. (Both failures involved individual load shedding relays.) The licensee has a reliability-centered maintenance program, including trending and root cause evaluation of equipment failures. The new Maintenance Rule requires similar programs to ensure the continued reliability of the diesel generators. The NRC staff evaluation for use of a 24-month surveillance frequency in contained in Section IV of this SE.

10. Existing TS 4.6.4.1 requires the demonstration, every 7 days, that instrument buses 1A, 1B, and 1C have nominal voltage indications. Similarly, existing TS 4.6.4.2 requires the demonstration, every 7 days, that instrument buses 1A, 1B, and 1C have the proper supply breaker alignment. In addition, existing TS 4.6.4.3 requires the demonstration, every 7 days, that instrument buses 1A and 1C have the proper static switch alignment.

   For buses necessary to support equipment required to be operable, improved TS SR 3.8.9.1 (in Modes 1, 2, 3, and 4) and SR 3.8.10.1 (in Modes 5 and 6) verify correct breaker alignment and voltage for instrument buses 1A, 1B, and 1C every 7 days. Improved TS SR

3.8.7.1 (static switch alignment to instrument buses 1A and 1C) and SR 3.8.7.2 (Class 1E constant voltage transformer supply to instrument bus 1B) in Modes 1, 2, 3, and 4 and improved TS SR 3.8.8.1 and SR 3.8.8.2, respectively, in Modes 5 and 6 for those buses necessary to support equipment required operable, verify the correct power sources to instrument buses 1A, 1B, and 1C every 7 days. A plant-specific description of the inverters reflects a design of only one inverter for bus 1A and one inverter for bus 1C. As a general provision to the TS, this requirement encompasses the existing TS requirements, and is therefore acceptable.

11. As shown in the improved TS, Figure B 3.3.2-1, instrument bus D is supplied by a non-diesel generator backed bus (MCC B). Upon loss of offsite power, this instrument bus becomes unavailable. Therefore, it is not included in improved TS LCO 3.8.7, LCO 3.8.9, or LCO 3.8.10. The Bases for these three LCOs state that the need for 120-Vac instrument bus D is addressed in LCO 3.3.2 and LCO 3.3.3. Table B 3.8.9-1 does not include 120-Vac instrument bus D in the ac and dc electrical power distribution systems. The licensee's existing TS have no operability requirements for 120-Vac instrument bus D, a nonsafety-related bus supplied by a nonsafety-related power source.

    The licensee stated that the reference to improved TS LCO 3.3.2 and LCO 3.3.3 in LCO 3.8.7, LCO 3.8.9, and LCO 3.8.10 provides information to ensure that appropriate actions are taken if 120-Vac instrument bus D is unavailable. Also, surveillances of 120-Vac instrument bus D are not required, since the affected instrumentation already has appropriate surveillances. However, one engineered safety feature actuation system function (LCO 3.3.2) and two post-accident monitoring instrumentation system functions (LCO 3.3.3) are partially (that is, one division of a functional unit) powered from 120-Vac instrument bus D. Consequently, the availability of 120-Vac instrument bus D directly affects the operability of only one channel of these functions. In addition, if 120-Vac instrument bus D loses power, a reactor trip could potentially occur should the active pressurizer control channel lose power. If this instrument bus is inoperable, the affected instrumentation must be declared inoperable. The operability requirements for this bus are part of the Safety Function Determination Program. As a general provision to the TS, this requirement encompasses the existing TS requirements, and is therefore acceptable.

The above changes are considered purely administrative changes in the statement of requirements in the improved TS, and are therefore acceptable.

3.3.8.2 Relocated Requirements

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate all or portions of existing TS 4.6.1.b.6 within the improved TS. Existing TS 4.6.1.b.6 verifies that each diesel generator is "aligned" to the associated emergency buses every 31 days when not in cold shutdown or refueling (in Modes 1, 2, 3, or 4). The requirement to verify that the diesel generator is aligned to provide standby power to the associated emergency buses is not explicitly stated in the improved TS. The definition of diesel generator operability and the associated action requirements are sufficient to ensure that the diesel generator remains aligned to provide standby power. This requirement is part of the definition of an operable diesel generator (improved TS 3.8.1, Bases). In addition, improved TS 3.8.1 requires two emergency diesel generators "capable of supplying their required onsite 480-V safeguards buses." The Bases state that diesel generator A is dedicated to safeguards buses 14 and 18, and diesel generator B is dedicated to safeguards buses 16 and 17. Improved TS SR 3.8.9.1 verifies that the bus tie breakers are open (Modes 1, 2, 3, or 4). Thus, the alignment of the emergency diesel generators is adequately controlled by the improved TS without requiring verification of alignment. The above changes are considered administrative changes in the location of the requirements within the TS and are therefore acceptable.

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate or reorganize all or portions of existing TS to licensee-controlled documents.

Existing TS	Title
3.7	Auxiliary Electrical Systems
4.6.1	Diesel Generators
4.6.2	Station Batteries
4.6.3	Preferred (Offsite) Power Supplies

The more significant changes resulting from the relocated items are as follows:

1. Existing TS 4.6.1.e.1 requires inspection of diesels "in accordance with the manufacturer's recommendations for this class of standby service." The required diesel generator inspection is relocated to the plant procedures under the control of 10 CFR 50.59. The licensee is participating in a program to develop performance-based diesel generator inspection criteria instead of the current-time directed inspections. This program is being developed with the full support of the diesel generator vendor (Coltec-Fairbanks Morse/ALCO) and six other participating utilities. With this program, the diesel generator inspection frequency is adequately controlled outside of the technical specifications related to the actual performance of the diesel generator. If the diesel generator performance requires inspections more frequently than once every 24 months, the licensee committed to pursue the necessary actions required by this performance-based program to

restore the diesel generator performance. No screening criteria apply for this requirement since manufacturer-recommended diesel generator inspections are not part of the primary success path assumed in the mitigation of a DBA or transient. Therefore, the requirement does not satisfy the technical specification screening criteria of the Commission's Final Policy Statement. Accordingly, relocating this requirement to the plant procedures is acceptable.

2. Existing TS 4.6.1.e.3.b requires test verification of maximum closure times every 18 months for the diesel generator load sequence timer circuit breaker. The licensee revised the requirement for diesel generator testing simulating a loss of offsite power in conjunction with a safety injection test signal. Specifically, the improved TS SR 3.8.1.9 verifies that the permanent and automatically connected emergency loads are energized during the test for actual or simulated loss of offsite power in conjunction with an actual or simulated SI signal. Details of the test acceptance criteria, such as circuit breaker maximum closure times, are relocated to the TRM and the improved TS Bases 3.8.1, "Applicable Safety Analyses." This level of detail is not specified in the NUREG-1431 and does not meet any of the four screening criteria in the Commission's Final Policy Statement. Therefore, relocating the required breaker closure times to the TRM is acceptable.

3. Existing TS 4.6.2.c requires the comparison of new battery test data to the old battery test data to detect signs of deterioration. The licensee stated that the requirement for trending battery test data is not specifically incorporated in the improved TS because this trending must be performed to meet the frequency requirements for SR 3.8.4.3. Also SR 3.8.6.1 and 3.8.6.6 verify that battery cell parameters are met every 92 days. These battery cell parameters provide actual acceptance criteria for battery operability, which if not met, have specific required actions.

IEEE Std 450-1987 states that the limits and corrective actions are meant to provide "optimum life of the battery." For example, a battery's electrolyte level is not a critical issue unless the plates are in danger of being exposed. Requiring the electrolyte level to be greater than the minimum water level indication mark on the battery cell provides a margin to exposing the plates. This is administratively controlled. Therefore, these battery parameters perform the same function as trending, in that they ensure that batteries remain at their optimum performance.

SR 3.8.4.3 verifies the battery capacity every 60 months or at an increased frequency in the event of degradation. In order to measure degradation, trending must be performed. Consequently, these SRs provide control equivalent to existing TS 4.6.2.c. After the monthly and quarterly battery checks, plant procedures require the review and verification of the battery surveillance data. The

test results are also added to the database to permit data trending. In addition, plant procedure changes are subject to an evaluation performed in accordance with 10 CFR 50.59. Thus, the programmatic battery parameter data review encompasses the existing TS requirement to compare the new battery test data to the old test data. Therefore, this relocation to procedures is acceptable.

4. Existing TS 3.7.2.2 specifies required actions for inoperable power sources and distribution systems, including two offsite sources, station service transformers (12A and 12B), and dedicated circuits (751 and 767). Existing TS 3.7.2.2.a permits indefinite operation with one offsite source inoperable, if all specified conditions are met. However, existing TS 3.7.2.7.b allows operation with only one offsite source and one diesel generator for up to 7 days. Improved TS 3.8.1 does not include action requirements for two offsite sources, transformers, and dedicated circuits since there are no existing TS requirements if one offsite source is inoperable.

   Consistent with the guidance of the improved TS format, the details of the second offsite power source requirements are relocated to the licensee-controlled TRM. The TRM requires an evaluation (per 10 CFR 50.59) for any changes.

5. Existing TS 4.6.2.e requires a discharge test of each 125-Vac battery at least once every 60 months. Existing TS 4.6.2.f accelerates the test frequency to every 12 months if degradation is indicated based on a battery capacity decrease of more than 10% between tests or if the battery capacity is less than 90% of the manufacturers rating. Improved TS SR 3.8.4.3 requires a battery performance test once every 60 months. The frequency is accelerated based on degradation or battery capacity changes with respect to expected battery life. The definition of "degradation" and "10% battery capacity decrease" is relocated to the TRM. This relocation is acceptable since the additional restrictions on battery capacity versus expected life in the improved TS ensures that the battery remains operable. The additional frequency changes based on "degradation" only provide additional margin. Therefore, controlling the definition of degradation in the TRM, which are under control of 10 CFR 50.59, is acceptable.

6. Existing TS 4.6.3.a.3 requires verification that tie breakers (52/BT16-14 and 52/BT17-18) between redundant divisions of 480-Vac safeguards buses are open when the RCS temperature is greater than 200 °F. Improved TS SR 3.8.9.1 specifies that the correct circuit breaker alignment is to be verified every 7 days. Thus, only the specific listing of the tie breakers is relocated to the Bases. Relocation of this level of detail to the Bases is consistent with NUREG-1431, which eliminates the need for TS changes when equipment identification numbers change. Further, the details identifying circuit breakers and their required positions are relocated to plant procedure. This procedure, which requires verification of

breaker positions, also requires an evaluation (per 10 CFR 50.59) for any changes. Thus, the alignment of the tie breakers is adequately controlled without adding this alignment verification to the improved TS. Therefore, this relocation is acceptable.

7. The licensee reviewed the records for the diesel generator loss of power with concurrent SI test (existing TS 4.6.1.e.3). These tests are currently conducted annually, with only two relay failures observed during the past 11 years. Neither reported failure would prevent the associated diesel generator from performing its safety-related function. (Both failures involved individual load shedding relays.) The licensee has a reliability-centered maintenance program, including trending and root cause evaluation of equipment failures. The new Maintenance Rule requires similar programs that ensure the continued reliability of the diesel generators. Additionally, the licensee changed the frequency of this testing from an 18-month surveillance to a 24-month surveillance.

   Relocating the required breaker closure times of existing TS 4.6.1.e.3 to the TRM is acceptable. If diesel generator performance declines following the change to 24 months, the licensee would implement the necessary actions via the performance-based diesel generator maintenance program or via implementation of the Maintenance Rule, required by June 1996. The NRC staff evaluation for use of a 24-month surveillance frequency is contained in Section 4.0 of this SE.

The above relocated requirements related to refueling operations are not required to be in the TS under 10 CFR 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. Further, they do not fall within any of the four criteria set forth in the Commission's Final Policy Statement, as discussed in the Introduction above. In addition, the NRC staff finds that sufficient regulatory controls exist under 10 CFR 50.59. Accordingly, the NRC staff concludes that these requirements may be relocated from the TS to the licensee's TS Bases, UFSAR, plant procedures, or TRM, as applicable.

3.3.8.3 More Restrictive Requirements

By electing to implement Section 3.8 of NUREG-1431 specifications, the licensee proposed a number of conditions that are more restrictive than those required by the existing TS. The more significant conditions are as follows:

1. Existing TS 3.7.1.1.b requires one train of 480-Vac buses (buses 14 and 18 or buses 16 and 17) to be operable for cold shutdown or refueling operations. Improved TS 3.8.10 addresses cold shutdown and refueling requirements for the 480-Vac safeguards buses (Modes 5 and 6). It also revises the requirements from requiring only one operable train to requiring the necessary train(s) to support all other LCO requirements. Consequently, one or both trains of 480-Vac buses may be required depending on other system requirements

(e.g., RHR). In Modes 5 and 6, sufficient electrical power redundancy must be available to mitigate an event coincident with either a loss of offsite power, loss of all onsite standby emergency power, or a worst-case single failure. This change ensures that all needed electrical support systems are operable to respond to a DBA or transient. Therefore, this more restrictive change is acceptable.

2. Existing TS 3.7.1.1.d requires one dc system for cold shutdown or refueling with one battery and at least 150 amperes of battery charging capacity for the battery required to be operable. Improved TS 3.8.5 addresses cold shutdown and refueling requirements for the batteries and battery chargers (Modes 5 and 6). Improved TS 3.8.6 addresses the battery cell parameters required for all operating modes. Improved TS 3.8.10 addresses the cold shutdown or refueling requirements for the dc distribution system (Modes 5 and 6). In the improved TS, the licensee revised the requirements from requiring only one operable train to require a sufficient number of trains to support all other LCO requirements. Consequently, one or both trains of dc power and associated battery and charger may be required depending on other system requirements (e.g., RHR). In Modes 5 and 6, sufficient electrical power redundancy must be available to mitigate an event coincident with either a loss of offsite power, loss of all onsite standby emergency power, or a worst-case single failure. This change ensures that all necessary electrical support systems are operable to respond to a DBA or transient. Therefore, this more restrictive change is acceptable.

3. Existing TS 3.7.1.1.e requires either 120-Vac instrument bus (1A or 1C) to be energized from its associated inverter. Improved TS 3.8.8 addresses cold shutdown and refueling requirements (Modes 5 and 6) for the ac instrument bus power sources. A plant-specific Bases description of the inverters reflects a design of only one inverter for bus 1A and one inverter for bus 1C. Improved TS 3.8.10 addresses cold shutdown or refueling requirements (Modes 5 and 6) for the ac instrument bus power distribution system. The improved TS revise the requirements from requiring only one operable train to requiring a sufficient number of trains to support all other LCO requirements. Consequently, one or more trains of ac instrument power and their associated power sources may be required depending on other system requirements (e.g., RHR). In Modes 5 and 6, sufficient electrical power redundancy must be available to mitigate an event coincident with either a loss of offsite power, loss of all onsite standby emergency power, or a worst-case single failure. This change ensures that all necessary electrical support systems are operable to respond to a DBA or transient. Therefore, this more restrictive change is acceptable.

4. Required actions in improved TS 3.8.3 for insufficient diesel generator fuel oil (Condition A) or excessive particulates in the

fuel oil (Condition B) while in cold shutdown and refueling are added to the improved TS for Modes 5 and 6. These revisions provide restoration times (48 hours and 7 days, respectively), for specified conditions consistent with the NUREG-1431. These times are sufficient to complete restoration of the degraded parameter before declaring the component inoperable. Based on the low probability of an event during the restoration period, and because the component remains capable of performing most required functions, and these conditions are not part of the current licensing basis, these more restrictive changes are acceptable.

5. In improved TS 3.8.6, the licensee added specific limits for battery cell parameters. These parameters form the basis for battery operability. Existing TS 4.6.2.a provides for monthly measurement and recording of the cell voltage of each cell and the specific gravity and temperature of a pilot cell of each battery. Existing TS 4.6.2.b requires the measurement and recording (every 31 days) of the specific gravity of each battery cell, the temperature of every fifth cell, and the amount of water added to each cell. However, no limits are specified.

   The basis for the specified electrolyte (above the top of the plates and not overflowing, verified every 31 days as specified in improved TS SR 3.8.6.1) is that IEEE Std 450-1987 requires adding water only if the low-level line is reached. Addition of water at this level is controlled administratively. This level (top of plates) is consistent with the allowable value specified in NUREG-1431, Table 3.8.6-1, Category C, and is acceptable.

   The basis for the surveillance limits for float voltage (greater than 2.07 volts, verified every 31 days as specified in SR 3.8.6.2) is that IEEE Std 450-1987, Section 4.4.3, requires an equalizing charge if any cell voltage is below 2.13 volts. Equalizing charges are administratively controlled. The 2.07 volts is consistent with the allowable value specified in NUREG-1431, Table 3.8.6.1, Category C, and the originally measured specific gravity of each battery. The change is therefore acceptable.

   The basis for the specified limits for pilot cell specific gravity (at least 1.188 for battery A and at least 1.192 for battery B, as specified in SR 3.8.6.3) is that this check is optional in IEEE Std 450-1987. This requirement is consistent with NUREG-1431, Table 3.8.6-1, and is acceptable.

   The basis for the specified temperature limits for the pilot cell (SR 3.8.6.4) is that IEEE Std 450-1987 requires this surveillance monthly. This surveillance is not explicitly required by NUREG-1431, Table 3.8.6-1; however, the SR is necessary to compensate for the specific gravity reading for temperature, and is acceptable.

The basis for the specified temperature limits for every fifth battery cell (at least 55 °F, verified every 92 days as specified by SR 3.8.6.5) is that IEEE Std 450-1987 requires measuring the temperature of representative cells quarterly. This is consistent with NUREG-1431, SR 3.8.6.3. Verifying that the temperature of every fifth cell is at least 55 °F is documented as the permissible plant-specific value, and is therefore acceptable.

The basis for the specified limits for the specific gravity of all cells (not more than 0.020 below the average of all connected cells and above the SR 3.8.6.3 limits, verified every 92 days as specified by SR 3.8.6.6) is that IEEE Std 450-1987 requires this quarterly. This is consistent with NUREG-1431, Table 3.8.6-1, and is acceptable.

Thus, the station battery testing requirements are revised, adding acceptance criteria, parameters, and associated actions for battery operability in Modes 1, 2, 3, 4, 5 and 6. These conditions are not part of the current licensing basis and enhance the monitoring of the condition of the batteries. Therefore, these more restrictive changes are acceptable.

6. Existing TS 4.6.1.b.1 requires verifying the level in each diesel generator day tank at least once every 31 days when not in cold shutdown or refueling. Improved TS SR 3.8.1.4 requires verification of the day tank level every 31 days when in Modes 1, 2, 3, and 4, and when that diesel generator is required to be operable, in Modes 5 and 6, ensuring that the diesel generator day tanks are filled when the DG is required to be operable. Therefore, these more restrictive changes are acceptable.

7. Existing TS 4.6.1.b.3 verifies that fuel transfer pump for each diesel generator can start and transfer fuel from the storage system to the day tank. This verification is performed once every 31 days when not in cold shutdown or refueling. Improved TS SR 3.8.1.5, verifies (every 31 days) that each diesel generator fuel transfer system transfers fuel from each storage tank to its associated day tank. This test ensures that the diesel generator fuel systems are operable. Therefore, these more restrictive changes are acceptable.

8. Existing TS 4.6.2.e requires a discharge test of each 125-Vac battery at least once every 60 months. The frequency is accelerated to every 12 months if degradation is indicated based on a battery capacity decrease of more than 10% between tests or if battery capacity is less than 90% of the manufacturers rating. By contrast, improved TS SR 3.8.4.3 requires a battery performance discharge test every 60 months. The SR 3.8.4.3 test frequency is accelerated if the battery shows degradation. The performance discharge test is required every 24 months when the battery has reached 85% of the expected life with at least 100% of the

manufacturer's rated capacity remaining. The performance discharge test is required every 12 months when the battery "shows degradation" or has reached 85% of the expected life with less than 100% of manufacturer's rated capacity remaining.

The accelerated tests are consistent with NUREG-1431 and are more conservative than existing TS since battery capacity changes are now based on expected life. That is, a battery capacity drop to 95% of the manufacturers rating would not cause an increase in surveillance frequency in the existing TS. However, this battery capacity drop would now require a test frequency of every 24 months in the improved TS.

9. Existing TS 4.6.1.b.5 requires a monthly diesel generator synchronization load test. The load must be at least 1950 kW, and less than 2250 kW for at least 60 minutes, but less than 120 minutes. Improved TS SR 3.8.1.3 specifies the same synchronizing and loading requirements every 31 days when in Modes 1, 2, 3, or 4. This startup test ensures that the diesel generators are operable. A Note requires that this test be performed sequentially and in conjunction with SR 3.8.1.2 or SR 3.8.1.9 to prevent unnecessary diesel generator starts. This change is acceptable since it supports diesel generator reliability and is consistent with NUREG-1431.

The NRC staff reviewed the above more restrictive requirements and concludes that they enhance the improved TS. Therefore, the more restrictive requirements are acceptable.

3.3.8.4 Less Restrictive Requirements

In electing to implement the Section 3.8 specifications, the licensee proposed a number of conditions that are less restrictive than those that are allowed by the existing TS. The more significant conditions are as follows:

1. Improved TS 3.8.1 allows one power source to supply a safeguards bus. It also allows a redundant system, subsystem, train, component, or device powered from the other safeguards bus to be inoperable for 12 hours, compared to the 1-hour outage allowed by existing TS 3.0.2. Existing TS 3.0.2 provides an exclusion for declaring a component inoperable if its offsite power source or diesel generator source is inoperable. This exclusion applies provided that two conditions are met: (a) either the corresponding offsite source or diesel generator must remain operable, and (b) the redundant component must remain operable with either its associated offsite power or diesel generator source operable. If either of these conditions is not met for greater than 1 hour, the plant must initiate shutdown actions. This requirement is revised and contained in improved TS 3.8.1.

Condition A of LCO 3.8.1 applies if an offsite power source is not available to one or more 480-Vac safeguards buses. Condition A is written so that if any feature on an unaffected bus is declared inoperable at the time of (or following) the loss of offsite power, then Required Action A.1 requires declaring the redundant component on the 480-Vac bus which has lost offsite power inoperable within 12 hours. In order to lose a safety function in this instance, a failure of either the diesel generator to the 480-Vac bus or the redundant component on the 480-Vac bus without power must occur. The probability of either event occurring in 12 hours is very low, especially coincident with an accident. However, if the diesel generator or the redundant component is declared inoperable, the safety function determination program requires immediate entry into LCO 3.0.3.

Ginna has two available sources of offsite power, including backfeeding through the main transformer (which further decreases the potential for this scenario for the loss of offsite power). Therefore, even though Condition A allows 12 hours before declaring a component inoperable as a result of its solely offsite power source being lost, the safety-related source of power to that component remains available. Thus, a Completion Time of 12 hours is acceptable because it allows time for the operator to evaluate and repair any discovered power source inoperabilities.

Condition B of LCO 3.8.1 applies if a diesel generator is unavailable. Required Action B.1 verifies the operability of the offsite power circuit every 8 hours if one diesel generator is inoperable. In addition, if any feature on an unaffected bus is declared inoperable at the time of (or following) the loss of the diesel generator, required Action B.2 requires that the redundant component on the 480-Vac bus which has lost the diesel generator must be declared inoperable within hours. In order to lose a safety function in this instance, either the offsite power sources to the 480-Vac safeguards buses must fail, or the redundant component on the bus with the inoperable diesel generator must fail. The probability of either event occurring in 4 hours is very low, especially coincident with an accident. However, if offsite power is lost, or the redundant component declared inoperable, the safety function determination program would require immediate entry into LCO 3.0.3. Further, Ginna has two available sources of offsite power, and the potential to backfeed the ac distribution system through the main transformer decreases the potential for this scenario for the loss of offsite power. Thus, a Completion Time of 4 hours is acceptable, allowing time for the operator to evaluate and repair any discovered diesel generator inoperabilities.

Condition C of LCO 3.8.1 applies if no offsite power is available to one or more 480-Vac safeguards buses, and one diesel generator is declared inoperable. If offsite power and a diesel generator are lost to the same bus, then Condition A of distribution systems (LCO 3.8.9) is entered allowing 8 hours to restore power to the ac bus. Current requirements do not address the loss of power for one train and loss of the diesel generator for the other train. Consequently, existing TS 3.0.1 requires the initiation of shutdown within 1 hour. The 8 hours allowed is discussed below. If separate buses are affected, improved TS Conditions A and B are both entered, essentially allowing either 72 hours or 7 days of operation, respectively, in this configuration. Based on these actions, Condition C allows 12 hours to restore either the offsite power or the inoperable onsite source if both losses affect a separate bus (rather than the 1-hour allowed by existing TS 3.7.2.2.c. This is acceptable due to the low probability of an accident and the potential for a second diesel generator to fail during this limited time period.

Improved TS 3.0.6 provides actions for when a single inoperability in a support system also results in inoperability of one or more related supported systems. Since this specification clarifies ambiguities and maintains actions within the realm of previous industry interpretations and NRC positions, this new provision does not impose any new requirements. Overall, the less restrictive changes discussed above are consistent with NUREG-1431 and Ginna safety analyses, therefore, these changes are acceptable.

2. Existing TS 3.7.2.2.b.1 specifies that the surveillance required by existing TS 4.6.1.b.4 and 4.6.1.b.6 for the operable diesel generator must be performed within 1 hour after one or both offsite power sources and one diesel generator become inoperable, and at least once every 24 hours thereafter. Existing TS 4.6.1.b.4 verifies that the diesel starts from normal standby conditions and attains rated voltage and frequency. Existing TS 4.6.1.b.6 verifies that the diesel generator is aligned to provide standby power to the associated emergency buses.

   Improved TS 3.8.1, Required Action B, provides required actions for an inoperable diesel generator. Required Action B.1 requires verification of the offsite power circuit to the affected bus once within 1 hour and every 8 hours thereafter. Required Action B.3 allows 24 hours to either determine the operable diesel generator is not inoperable because of a common cause failure, or to perform SR 3.8.1.2 by verifying that the diesel generator starts from standby conditions and achieves rated voltage and frequency. Thus, the licensee revised the actions for an inoperable diesel generator. Specifically, the licensee eliminated the testing of the operable diesel generator if it can be determined within 24 hours, that the operable diesel generator is not inoperable because of common cause failure. The licensee also required verification of the offsite power circuit to the affected ac distribution train once within 1 hour and once every 8 hours thereafter (Required Action B.1). In addition, the operable diesel generator must only

be tested once during the 7-day allowed outage for the inoperable diesel generator.

The revised action for the operable diesel generator eliminates unnecessary testing during a period in which the plant relies on only one diesel generator. Minimizing diesel generator starts avoids unnecessary diesel wear, thereby enhancing overall diesel generator reliability as discussed in GL 84-15. Therefore, improved TS 3.8.1, Required Action B.3.1, includes the option for determining, upon diesel generator failure, that no common-mode failures exist. This determination precludes unnecessary testing of the remaining diesel generator. This less restrictive change is consistent with NUREG-1431. Since the verification of offsite power is now required and operability of the second diesel generator is maintained, this change is acceptable.

3. Existing TS 3.7.2.2.c provides a Completion Time of 1 hour to reenergize any 480-Vac safeguards bus (bus 14, 16, 17, or 18) that becomes de-energized. By contrast, improved TS 3.8.9, Condition A, provides 8 hours to restore the bus to operable status. The revised time for the action to re-energize the 480-Vac safeguards bus is consistent with NUREG-1431, which requires restoration of the bus and the associated load centers, motor control centers (MCCs), and distribution panels that comprise the ac electrical train.

   The probability of an accident within this 8-hour period is very low. In addition, the 8-hour period gives the operators time to restore the inoperable ac electrical train before requiring a plant shutdown with only one train available. Also, during the 8-hour Completion Time, the redundant electrical train remains capable of performing its safety-related function. This enhances safety by not diverting the operator's attention from the evaluations and actions necessary to restore power to the affected train by commencing an unneeded shutdown.

   Existing TS 3.7.2.2.c applies only to the 480-Vac safeguards buses, and not to the MCCs and distribution panels supplied by these buses. There are no current requirements on the ac electrical distribution system. Consequently, if an MCC supplied by any of the four 480-Vac safeguards buses is declared inoperable, Ginna can enter the LCOs of the components supplied by the MCC, which generally have Completion Times of 72 hours or greater. The improved TS limit the use of the MCCs to 8 hours. Based on the above, the allowance of 8 hours (versus 1 hour) to reenergize a 480-Vac safeguards bus or associated MCC is acceptable for this less restrictive change.

4. Existing TS Table 4.1-2, "Functional Unit 16," requires daily verification of the diesel fuel inventory. Improved TS SR 3.8.1.4 verifies the fuel oil level in the diesel day tanks every 31 days.

Improved TS SR 3.8.3.1 requires verification every 31 days of an onsite supply of fuel oil of at least 5,000 gallons for each diesel generator in Modes 1, 2, 3, and 4, and for the diesel generator required to be operable in Modes 5 and 6. Because of the passive design of the fuel oil storage tanks and the various level alarms, the 31-day verification of the level is acceptable.

5. Existing TS 4.6.1.e.2 requires a diesel generator load rejection test. In addition, every 18 months, existing TS 4.6.1.e.3 requires the following:

   a. simulation of a loss of offsite power in conjunction with a safety injection test signal;

   b. deenergizing and load shedding tests of the 480-Vac safeguards buses;

   c. diesel generator automatic start and operation test; and,

   d. test verification of the load sequence timer.

   The test also verifies that diesel generator trips (except for engine overspeed, low lube oil pressure, and overcrank) are bypassed because of an SI signal.

   Improved TS SR 3.8.1.7, diesel generator load rejection test, SR 3.8.1.8, diesel generator trips, and SR 3.8.1.9, de-energizing, load shedding, and diesel generator auto-start and loading tests of the 480-Vac safeguards buses are required every 24 months. These tests are equivalent to existing TS 4.6.1.e.2 and 4.6.1.e.3.

   The licensee reviewed records related to performance of the diesel generator load rejection testing (existing TS 4.6.1.e.2). No failures were observed since this test was first performed in 1969. While this test has historically been performed on an annual basis (because of the 12-month refueling cycles), the licensee found no historical information that would refute an increased surveillance interval of 24 months. If diesel generator load rejection performance declines following the change to 24 months, the licensee will implement the necessary actions via the performance-based diesel generator maintenance program or via implementation of the Maintenance Rule, required by June 1996.

   The licensee also reviewed the records for the diesel generator loss of power with concurrent safety injection test (existing TS 4.6.1.e.3). These tests are currently conducted annually, with only two relay failures observed during the past 11 years. Neither reported failure would prevent the associated diesel generator from performing its safety-related function. (Both failures involved individual load shedding relays).

The licensee has a reliability-centered maintenance program, including trending and root cause evaluation of equipment failures. The new Maintenance Rule requires similar programs that ensure the continued reliability of the diesel generators. The licensee's reliability-centered maintenance program provides acceptable testing for the diesel generators, and the Maintenance Rule provides additional evidence of diesel generator reliability. As a result, the lengthening of the interval between these tests from the current 18 months to 24 months is acceptable. The NRC staff evaluation for use of a 24-month surveillance frequency is contained in Section 4.0 of this SE.

6. Existing TS 4.6.2.d requires a battery load test every 12 months, with a possible 3-month extension. Plant procedures demonstrate that the batteries will sustain the expected emergency load profile for 4 hours without the battery terminal voltage falling below a specified value. Improved TS SR 3.8.4.2 requires a battery service test every 24 months. The only difference between a "load" test and "service" test is the name. Otherwise, the testing requirement remains the same. The increase in surveillance interval from 12 months to 24 months follows the recommendations of IEEE Std 450-1987. Section 5.3 states that the battery service test is required for nuclear applications, but specifies no testing interval. The Electric Power Research Institute (EPRI) provides guidance for batteries (Nuclear Maintenance Applications Center, Stationary Battery Maintenance Guide, TR-100248, dated December 1992). This guidance specifies a service test frequency of "annually or each refueling outage." Plant records show that, since the current batteries were installed in 1986 and 1990, neither battery has failed this service test.

   The battery service test is in addition to the monthly and quarterly verifications required by improved TS SR 3.8.6.1 and SR 3.8.6.2. Additionally, the battery performance discharge test of improved TS SR 3.8.4.3 can substitute for the service test of SR 3.8.4.2. This test is required annually if the battery shows deterioration or has reached 85% of its expected life with the remaining capacity less than 100% of the manufacturer's rating. Based on the annual requirements for a performance discharge test on a deteriorating battery, the battery service test with a 24-month frequency is acceptable. The NRC staff evaluation for use of a 24-month surveillance frequency is contained in Section 4.0 of this SE.

7. Existing TS 4.6.3.a requires verifying every 7 days, nominal voltage indications on the high-voltage side of transformers 12A and 12B, as well as nominal voltage indications on 4160-Vac buses 12A and 12B.

   Nominal voltage on the high-voltage side of transformers 12A and 12B is not an assumption of any accident analysis. In addition,

the 4160-Vac power supplied from these transformers must be transformed down to 480-Vac by one of four transformers before reaching the four 480-Vac safeguards buses. If sufficient voltage is not available on transformers 12A and 12B, the 480-Vac safeguards buses would automatically trip, requiring the start of the associated diesel generator. Verifying that indicated power is available to each 480-Vac safeguards bus per improved TS SR 3.8.1.1 ensures that an offsite power source is available and capable of supplying accident loads. In addition, improved TS SR 3.8.9.1 verifies acceptable voltage on the 480-Vac safeguards buses. Verifying breaker alignments and 480-Vac bus voltage ensures that the accident assumptions are met, and that all intermediate buses in the distribution system are powered. Circuit breaker position is controlled by plant procedures, which require verification of breaker positions once a day. These procedures require an evaluation (per 10 CFR 50.59) for any changes.

8. Existing TS 4.6.3.b requires demonstration at least once every 18 months, of the transfer of the unit power supply from the 4160-Vac buses 12A (normally transformer 12A) and 12B (normally transformer 12B) to each bus' alternate supply, transformers 12B and 12A, respectively. Improved TS SR 3.8.1.6, verifies, at a minimum frequency of 24 months, the transfer of AC power sources from the 50/50 mode to both the 100/0 and the 0/100 modes. The NRC staff evaluation for use of a 24-month surveillance frequency is contained in Section 4.0 of this SE.

9. Existing TS 4.6.3.a.2 verifies every 7 days that 4160-Vac circuit breakers 12AX or 12BX and 12AY or 12BY are open, ensuring that both offsite sources are not supplying the same 4160-Vac bus (parallel operation of the sources). If parallel operation of the sources were to occur, a single fault could fail both offsite power sources. This scenario is bounded by operation in the 100/0 mode (i.e., one offsite power source supplying both buses), and when the plant is backfed through the main transformer as a secondary power supply. The configuration of these breakers is controlled by plant procedures, which require verification of breaker positions once a day. This procedure also requires an evaluation (per 10 CFR 50.59) for any changes. Improved TS SR 3.8.1.1 is required in all operating modes, but does not specify the breakers to be verified operable. For required offsite power sources in Modes 5 and 6, improved TS SR 3.8.1.1 also verifies the correct breaker alignment and power availability from the offsite circuit to each 480-Vac safeguards bus. Improved TS SR 3.8.9.1 verifies the correct breaker alignment for the 480-Vac safeguards buses. The improved TS surveillances encompass the existing TS surveillances and other provisions are in place to assure that offsite power sources are not improperly aligned. Therefore, the specific details of which circuit breakers must be open need not be contained in the TS.

10. The diesel fuel oil test requirements of Existing TS 4.6.1.d are relocated to Specification 5.5.12 and are proposed to be identified as a "program" consistent with the format of NUREG-1431. In addition, the fuel oil testing program was revised to expand the testing requirements consistent with NUREG-1431 and delete the 92-day test of the stored fuel oil. The fuel oil is now required to be tested for viscosity, water, and sediment before being placed in the storage tanks, as such testing for fuel quality after fuel is added to the storage tanks is no longer required. This change reduces the potential to cause the diesel generators to be inoperable as a result of poor fuel oil quality.

These less restrictive requirements are acceptable, because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with current licensing practices, operating experience, and plant accident and transient analyses. They give reasonable assurance that the public health and safety will be protected.

3.3.9 Refueling Operations

3.3.9.1 Significant Administrative Changes

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed administrative changes to bring the existing TS into conformance with NUREG-1431 improved TS. The more significant changes resulting from the administrative items are as follows:

1. Existing TS 3.8.1.d (footnote *) and existing TS 3.8.1.g (footnote *) allow that either the preferred or the emergency power source may be inoperable for each residual heat removal loop. This detail is encompassed in the definition of operability described in new TS 1.1, and the electric power requirements contained in Section 3.8 and, therefore, these existing footnotes are no longer needed in the improved TS. The above changes are considered purely administrative changes in the statement of requirements in the improved TS, and are therefore acceptable.

2. The applicability of existing TS 6.8 was revised from "during refueling operations" to "CORE ALTERATIONS and movement of irradiated fuel assemblies within containment." This change to adopt the NUREG-1431 TS is an equivalent change since refueling operations can only be related to core alterations and the movement of irradiated fuel assemblies within containment.

3.3.9.2 Relocated Requirements

In accordance with the guidance in NUREG-1431, the licensee has proposed to relocate all or portions of the following existing TS within the improved TS:

Existing TS	Title
3.6.1.b and c	Containment Integrity

The more significant changes resulting from the relocated items are as follows:

1. Existing TS 3.6.1.b requires containment integrity with the vessel head removed, unless boron concentration is greater than 2000 ppm. Further, existing TS 3.6.1.c restricts operations that involve reactivity changes by rod drive motion or by boron dilution whenever containment integrity is not intact, unless boron concentration is greater than 2000 ppm.

   Improved TS LCO 3.9.1 requires that the boron concentration of the RCS shall be maintained within the limit specified in the COLR (2000 ppm) during Mode 6. Mode 6, in turn, is defined in improved TS Table 1.1-1 as any time "one or more reactor vessel head closure bolts [are] less than fully tensioned." Therefore, the mode of applicability for improved TS LCO 3.9.1 bounds "when the reactor head is removed," as specified in existing TS 3.6.1.b.

   In addition, improved TS required actions state that, in the event that boron concentration limits are not met, core alterations and positive reactivity additions are to be suspended consistent with existing TS 3.6.1.c. These actions effectively prevent the two accidents of concern in Mode 6 (i.e., a fuel handling accident and a boron dilution event).

   The containment integrity requirements in existing TS 3.6.1.b are addressed in improved TS LCO 3.9.4, "Containment Penetrations," for core alterations and during movement of irradiated fuel assemblies within containment. Therefore, the existing TS 3.6.1.b requirement for boron concentration limits being greater than 2000 ppm when the reactor head is removed is effectively relocated to improved TS LCO 3.9.1. The required actions for improved TS LCO 3.9.1 require suspension of core alterations and positive reactivity additions whenever the boron concentration limit is not met in Mode 6, regardless of the containment status. Therefore, existing TS 3.6.1.c is being relocated in its entirety to improved TS LCO 3.9.1.

The above changes are considered administrative, affecting only the location of the requirements within the TS, and are therefore acceptable.

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate or reorganize all or portions of the following existing TS to licensee-controlled documents:

Existing TS	Title
3.8	Refueling
4.11.2	Residual Heat Removal and Coolant Circulation

The more significant changes resulting from relocated items are as follows:

1. Existing TS 3.8.1.f requires direct communication between the control room and the refueling cavity manipulator crane during core alterations. This communication must be maintained to ensure that refueling personnel can promptly be informed of significant changes in the plant status or core reactivity conditions during refueling. The refueling system design accident or transient response does not take credit for communications, and other measures are in place to ensure safe refueling operations. Therefore, the licensee relocated the requirements to plant procedures, which will be controlled in accordance with 10 CFR 50.59.

2. Existing TS 3.8.1.c requires continuous monitoring of core subcritical neutron flux, with audible indication in the containment during core alterations. Such monitoring promptly notifies refueling personnel of significant changes in the plant status or core reactivity conditions during refueling. Also, other measures are in place to ensure safe refueling operations, and the refueling system design accident or transient response does not take credit for refueling floor communications. Therefore, the licensee relocated the requirements to plant procedures, which will be controlled in accordance with 10 CFR 50.59.

3. Existing TS 4.11.2.2 requires demonstration of residual heat removal (RHR) pump operability by performance of pump surveillances specified in 10 CFR 50.55a. The proposed improved TS SR 3.9.4.2 requires verification that the breaker is correctly aligned and that indicated power is available for the non-operating pump. The specific testing requirement was retained, but was relocated to the IST program (Specification 5.5.7), consistent with NUREG-1431.

   Improved TS 3.9.4 provides adequate verification that a second RHR pump can be placed in operation to maintain decay heat removal and reactor coolant circulation. Additionally, in Mode 6, the RHR system is not in service to mitigate any events or accidents evaluated in the safety analysis. The intent of the RHR operability requirements is to prevent boron dilution events by ensuring mixing of the borated coolant. A significant amount of time exists for operators to respond to a loss of RHR cooling before the coolant boils.

4. The licensee did not add existing TS 3.8.1.b, concerning the refueling or Mode 6 requirement for the containment radiation monitors used to ensure personnel safety. No screening criteria apply for this requirement because the process variable of the LCO is not an initial condition of a DBA or transient analysis. Further, the containment radiation monitors are a non-significant risk contributor to core damage frequency and offsite release. Therefore, the requirement specified for this function does not satisfy the Commission's Final Policy Statement TS screening criteria, and is relocated to the plant procedures.

The above relocated requirements related to refueling operations are not required to be in the TS under 10 CFR 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. Further, they do not fall within any of the four criteria set forth in the Commission's Final Policy Statement, as discussed in the Introduction above. The NRC staff concludes that the control of these provisions under 10 CFR 50.59 is acceptable, that the regulatory requirements provide sufficient control of these provisions, and that removing them from the TS is acceptable. Accordingly, the NRC staff concludes that these requirements may be relocated from the TS to the licensee's procedures, or IST program, as applicable.

3.3.9.3 More Restrictive Requirements

By electing to implement the Specifications of NUREG-1431, Section 3.9, the licensee adopted a number of conditions that are more restrictive than those required by the existing TS. The more significant conditions are as follows:

1. In existing TS 3.8.1.c, the licensee revised the requirement describing the specific applicability of the SRMs. The phrase "whenever geometry is being changed" is covered by the new TS definition of Mode 6. The requirement that one SRM be operable when core geometry "is not being changed" is covered by the required action [TS 3.9.3, RAs A.1 and A.2] for one inoperable SRM. This would restrict CORE ALTERATION and positive reactivity additions when core geometry is not being changed. Required actions [TS 3.9.3, Conditions B and C] were also provided to address the instance when two SRMs become inoperable, or when the audible indication is lost. These new actions require verification of boron concentration every 12 hours, and ensure the stabilized condition of the reactor core.

   Existing TS 3.8.1.c requires one operable SRM during Mode 6 when core geometry is not being changed, and two operable SRMs during refueling when the core geometry is being changed. Improved TS LCO 3.9.2 requires two SRMs operable at all times during Mode 6. This represents the lowest functional capability or performance level of equipment required for safe operation of the facility. With only one SRM operable, Required Actions A.1 and A.2 are no more limiting than what is specified by the existing TS LCO requirement (i.e., no fuel movement is allowed). The change is considered more restrictive only because the improved TS places the plant in a specific condition, whereas the existing TS LCO would continue to be met.

   The existing TS also requires the suspension of operations that may increase core reactivity. The licensee revised the existing TS to add the requirements denoted by LCO 3.9.2, Required Actions B.1, B.4, and C.3, when two SRMs become inoperable, or when the audible indication is lost. These new actions require the immediate initiation of action to restore one SRM to operable status, as well as verification of boron concentration every 12 hours. These new required actions ensure the stabilized condition of the reactor core.

2. With the adoption of mode definitions in improved TS Section 1.1, the licensee revised the requirement in existing TS 3.8.1.e describing the specific applicability and frequency of the boron concentration sampling. The phrase "immediately before reactor vessel head removal and while loading and unloading fuel from the reactor" is covered by the new TS definition of Mode 6. This would additionally require boron concentration sampling throughout Mode 6.

   Existing TS 3.8.1.e requires that the minimum boron concentration be maintained before reactor head removal and while loading and unloading fuel from the reactor. Improved TS LCO 3.9.1 requires that the minimum boron concentration be maintained during Mode 6. The improved TS defines Mode 6 as "when one or more reactor vessel head closure bolts [are] less than fully tensioned." The improved TS also requires the SR be met before entering Mode 6 (per LCO 3.0.4). Therefore, the existing TS requirement to ensure that the minimum boron concentration is maintained "prior to reactor head removal" is equivalent to the improved TS requirements. However, the existing TS only requires the minimum boron concentration requirement when loading and unloading fuel.

   The improved TS requires continuation of the minimum boron concentration requirement throughout Mode 6. The literal reading of the existing TS could be inferred to exclude, as a TS requirement, the requirement to maintain the minimum boron concentration when fuel is not in the process of being loaded or unloaded. Since this requirement could be inferred to be controlled administratively, the improved TS requirement is considered more restrictive than that of the existing TS.

3. The licensee revised Table 4.1-1, "Functional Unit #3, Nuclear Source Range," to add a requirement establishing a surveillance for SRM CHANNEL CALIBRATION in Mode 6. This calibration consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to baseline data. This requirement is consistent with existing Ginna procedures.

4. The licensee added improved TS SRs 3.9.4.1 and 3.9.5.1 which require verification every 12 hours during Mode 6 that one RHR loop is in operation and circulating reactor coolant. This ensures that the RCS is being mixed as assumed for boron dilution events and that decay heat removal continues during both low and high RCS inventory levels in shutdown conditions.

The NRC staff reviewed the above more restrictive requirements, and concludes that they enhance the improved TS. Therefore, the more restrictive requirements are acceptable.

3.3.9.4 Less Restrictive Requirements

In electing to implement the specifications of NUREG-1431, Section 3.9, the licensee proposed a number of conditions that are less restrictive than those allowed by the existing TS. The more significant conditions are as follows:

1. With the adoption of mode definitions in improved TS Section 1.1, the licensee revised the requirement in existing TS 3.8.1.e describing the specific applicability and frequency of the boron concentration sampling. Specifically, the sampling frequency was revised from requiring boron sampling twice each shift to require sampling every 72 hours. This revision considers the large volume of the refueling canal, RCS, and refueling cavity, and is adequate to identify slow changes in boron concentration. Rapid changes in boron concentration, described in UFSAR 15.4.4.2, are detected by the SRM instrumentation required by new TS 3.9.2.

   Changing the surveillance frequency from twice each shift to once every 72 hours does not impose a significant safety question in the operation of the plant. This limit ensures that the reactor remains subcritical during Mode 6. The boron concentration limit is based in part on the assumptions that (1) control rods and fuel assemblies are in the most adverse configuration (least negative reactivity) allowed by plant procedures, and (2) core reactivity is at the beginning of each fuel cycle. These conservatisms, along with the fact that the operator has prompt and definite indication in the control room of a significant boron dilution event, provide assurance that the proposed change in the surveillance frequency does not impose a significant safety question in the operation of the plant. The 72-hour frequency is consistent with NUREG-1431, and is based on industry operating experience (which has shown that 72 hours is adequate).

2. In developing the improved TS, the licensee did not adopt the requirements (in existing TS Table 4.1-1, "Functional Unit #3, Nuclear Source Range") for bistable actions and checks with step-counters during the once-per-shift channel check surveillance for an SRM CHANNEL in Mode 6. Requirements that specify methods and tests for meeting TS requirements are moved to the TS Bases and procedures for performing this surveillance, consistent with the guidance of NUREG-1431.

3. The existing TS 4.11.2.1 requirement to require verification that the RHR pump is in operation and circulating water through the RHR loop once every 4 hours was changed to 12 hours consistent with SR 3.9.3.1 and SR 3.9.4.1. The change in frequency is based on the consideration that flow, temperature, pump control, and alarm

indications are available to the operator in the control room for monitoring the RHR system.

The purposes of the RHR system in Mode 6 are to remove decay heat from the RCS, and to mix the borated coolant to prevent thermal and boron stratification. The SR only requires the verification, through indication in the control room, that the RHR loop is in operation. This SR is redundant with regard to many other indications that would alert the operators should an inadvertent loss of RHR loop occur. As a result, the change in frequency is not significant to safe operation of the plant since the available indication and operator response to a loss of RHR loop cooling is unchanged. Moreover, LCO 3.9.3 allows the RHR loop to be removed from operation during short durations. These short durations will not result in challenges to the fission product barrier or in coolant stratification, because decay heat is removed by natural convection to the large mass of water in the refueling cavity. A frequency of 12 hours is adequate because of the alarms and indications available to the operators with respect to RHR pump and loop performance.

4. Existing TS 4.11.3.1 requires verification of water level within 2 hours before fuel assemblies or control rods in containment begin moving, and once every 24 hours thereafter. By contrast, improved TS SR 3.9.5.1 requires verification of water level within 24 hours before fuel assemblies in containment are moved (in accordance with SR 3.0.4), and once every 24 hours thereafter. The two requirements differ in the time allowed for initial performance of the SR to ensure LCO operability, and thereby ensure safe operation of the plant, before entry into a specified condition as defined by the LCO applicability. This change has minimal effect on safe operation of the plant since, in both cases, the water level meets the requirements of the LCO before the mode change. The water level is not expected to change significantly during the additional 22 hours now allowed, because administrative controls exist over valve positions, control room alarms, control room indicators, and plant personnel located inside containment during this period who could observe a significant change in water level.

5. Improved TS SR 3.9.5.1 removes the flow rate verification requirements for the RHR loop in operation. For Ginna, the boron dilution event is the only event postulated to occur in Mode 6 which assumes that the RHR system is in operation. The Ginna UFSAR, Section 15.4.4.2 (for boron dilution in Mode 6), assumes uniform mixing of the borated coolant as a result of a RHR pump being in operation without specifying a RHR pump flow rate. Therefore, there is no analytical basis for inclusion of a flow rate in the SR. However, the words "and circulating reactor coolant" are added to SR 3.9.5.1 and discussed in the TS Bases. This is an implied function for an RHR loop in operation, and is

consistent with the safety analysis and improved TS SR 3.4.8.1, "RCS Loops-Mode 5, Loops Not Filled."

6. The requirement of existing TS 3.8.2 to cease "operations which may increase the reactivity of the core" was not included in improved TS 3.9.3 for containment penetration operability requirements since the licensing basis for establishing containment is to mitigate a fuel handling accident. The reactivity of the core is an assumption of a boron dilution event which is adequately addressed by other LCOs.

The NRC staff reviewed the above less restrictive requirements, and finds that they are acceptable because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with existing licensing practices, operating experience, and plant accident and transient analyses, and provide reasonable assurance that the public health and safety will be protected.

3.4 Design Features

This section contains the same material found in the existing TS, except for those less restrictive specification changes adopting NUREG-1431 which, if altered in accordance with 10 CFR 50.59, would not result in an unreviewed safety question, much less in a significant impact on safety (the criterion set forth in 10 CFR 50.36(c)(4)). In adopting the guidance of NUREG-1431, the licensee retained (in improved TS 4.3.1.1.c) the existing TS 5.4.4 and 5.5 requirements regarding acceptable locations for storing canisters containing consolidated fuel rods. Specifically, canisters may be stored in either Region 1 or Region 2 of the spent fuel pool (SFP), provided that the average burnup, initial enrichment, and average decay heat limits of the fuel assembly from which the rods were taken are met. The two fuel pool regions are defined in improved TS LCO 3.7.13.

3.4.1 Significant Administrative Changes

In accordance with the guidance in the Final Policy Statement, the licensee proposed the following administrative changes to bring the existing TS into conformance with NUREG-1431:

1. Existing TS 5.1 includes Figure 5-1, which shows a map of the Ginna site and surrounding areas giving details of the exclusion area boundary (also called the unrestricted area boundary). In place of this figure, improved TS 4.1 includes a description of the site location and definition of the exclusion area boundary distances from the centerline of the plant. The descriptive requirements result in the same limits as the existing requirements, because they represent an equivalent presentation of the existing TS intent.

2. The licensee revised existing TS 5.3.1.b to increase the fuel enrichment limit from 4.25 weight percent to 5.05 weight percent.

The NRC staff approved this change via license amendment No. 60, issued February 6, 1996.

The NRC staff concludes that the changes are purely administrative, and are therefore acceptable.

3.4.2 Relocated Requirements

In accordance with the guidance in NUREG-1431, the licensee proposed to relocate all or portions of the following existing TS within the improved TS:

Existing TS	Title
5.3.1.b	Reactor Design Features - Reactor Core
5.4	Fuel Storage
Figure 5.4-1	Spent Fuel Storage Racks
Figure 5.4-2	Regions of Acceptability and Unacceptability for Storage of Spent Fuel in Region 2

The more significant changes resulting from the relocated items are as follows:

1. Existing TS 5.3.1.b includes a description of the fuel storage design feature with respect to the maximum enrichment weight percent. In addition, existing TS 5.3.1.b denotes the requirements for new fuel similar to the requirements denoted in improved TS 4.3.1.2.a. The difference between the existing and improved TS is that the improved TS relates to storage of new fuel, while the existing TS can be interpreted to relate to acceptance of reload fuel. A fuel handling accident involving the reload fuel before placement in the storage racks is not of concern with respect to offsite doses, since the fuel has not yet been irradiated with source terms being generated. Therefore, applying existing TS 5.3.1.b requirements to storage of the new fuel per specification 4.3.1.2.a is acceptable.

2. The licensee relocated the description of the fuel storage design features from existing TS 5.4.1, 5.4.2, 5.4.6, and Figures 5.4-1 and 5.4-2, to Sections 3.7 and 3.9. Specifically, these features are discussed in LCOs 3.7.11, 3.7.12, 3.7.13, and 3.9.1 as appropriate, denoting spent fuel storage regions and borated water concentrations. In addition, the licensee added appropriate required actions to address an instance in which SFP water level, boron concentration, or SFP region storage requirements are not met.

In accordance with the guidance in NUREG-1431, the licensee proposed to relocate or reorganize all or portions of the following existing TS to licensee-controlled documents:

Existing TS	Title
5.1	Site
5.2.1	Reactor Containment
5.2.2	Penetrations
5.2.3	Containment Systems
5.3.1	Reactor Core
5.3.2	Reactor Coolant System
5.4	Fuel Storage
5.5	Waste Treatment Systems

The more significant changes resulting from relocated items are as follows:

1. Existing TS 5.1.1 and 5.1.2 include a site map (shown in Figure 5.1-1) that depicts the Ginna exclusion area boundary (also called the unrestricted area boundary) for the purposes of implementing Ginna Radiological TS, and for evaluating radiological releases to the unrestricted area. In place of the figure, improved TS 4.1 includes a description of the site location and the exclusion area boundary. The specific boundary for the unrestricted area remains detailed in UFSAR Section 2.1.2 and Figure 2.1-2. The requirements for and restrictions on locating the exclusion area boundary must conform to regulations found in 10 CFR Part 100. Evaluation of changes to this feature of the facility is required in accordance with 10 CFR 50.59 and 10 CFR Part 100, as applicable. However, relocation of the existing TS 5.1 design feature figure, showing the location of the exclusion area boundary, will not significantly affect the safe operation of the facility because the UFSAR descriptions will continue to provide the information necessary to establish the appropriate limits required by 10 CFR Part 100.

2. Existing accident mitigation TS concerning reactor containment (5.2.1), penetrations (5.2.2), and containment systems (5.2.3) remain detailed in UFSAR Sections 3.8.1 and 6.2. Existing TS for the reactor coolant system design (5.3.2) remain detailed in UFSAR Sections 3.7.1 and 5.0, and existing TS for waste treatment systems design (5.5) remain detailed in UFSAR Section 11.0.

   Changes to these facility design parameters are controlled by the requirements of 10 CFR 50.59. Furthermore, these design parameters relate to existing TS LCOs that establish acceptable requirements for ensuring that performance of the containment structure and containment reactor coolant system is maintained, and that any changes which may involve an unreviewed safety question would receive prior NRC staff review and approval.

   Since the features with a potential to impact safety are sufficiently addressed by LCOs, and since the associated design features would not significantly affect safety, if altered in accordance with 10 CFR 50.59, the criterion of 10 CFR 50.36(c)(4) for including the above design features in the TS is not met.

3. Existing TS 5.3.1.a and 5.3.1.c describe the reactor core design features. These descriptions include the approximate total mass of uranium dioxide pellets; the use of Zircaloy-4; the fuel rod positions in a fuel assembly; reporting requirements regarding fuel assembly rod replacement limits per refueling; fuel assembly design features regarding guide tubes, instrument thimbles, and array; and rod cluster control (RCC) assembly design parameters including control cladding consisting of silver-indium-cadmium. The licensee revised the TS section concerning design features, consistent with the standard guidance of NUREG-1431. Specifically, the revised TS include the amount, kind, and source of nuclear material related to the reactor core.

   The approximate total mass of the uranium dioxide pellets has been relocated to UFSAR Table 4.2-1. The discussion concerning use of Zircaloy-4 has been moved to improved TS 4.2.1. This information is also provided in UFSAR Sections 4.2.3.1, 4.2.3.1.6, and 4.1.3. Descriptions of the fuel rod positions have been relocated to UFSAR 4.2.3.1. The reporting requirements for fuel rod replacement are relocated to Ginna procedure A-25.6. The fuel assembly design features have been relocated to UFSAR Section 4.2.3.1 and Table 4.2-2. The RCC design parameters have been relocated to UFSAR 4.1.1, 4.2.3.1, 4.2.3.2, and 4.2.2. The change control process governing future changes to the UFSAR and procedure A-25.6 complies with 10 CFR 50.59. These relocated items do not meet the criterion for inclusion of design features in the TS per 10 CFR 50.36(c)(4).

4. The licensee did not add the existing TS 5.4.3 description of the fuel storage design feature, denoting the 60-day limit on storage of discharged fuel assemblies in Region 2. No screening criteria apply for the time limit on storage of discharged fuel assemblies in Region 2. The existing 60-day limit was established to provide sufficient margin in spent fuel pool temperature calculations as a result of decay heat loads in Region 2 from discharged fuel assemblies. The spent fuel pool cooling system and, thus, the associated restriction on heat load, prevent structural integrity damage to the spent fuel pool. Nonetheless, they are not assumed to function to mitigate the consequences of a design basis accident (DBA). The restriction on heat load is neither used for, nor capable of, detecting a significant abnormal degradation of the reactor coolant pressure boundary before a DBA. The restriction on heat load is a non-significant risk contributor to core damage frequency and offsite doses.

   The discussion related to storage in a close packed array utilizing fixed neutron poisons in each location has been relocated to UFSAR Sections 9.1.2.1.1 and 9.1.2.2.2. In addition, since these details do not meet the intent of the Commission's Final Policy Statement TS screening criteria, this requirement may acceptably be relocated to the TRM.

Since the features with a potential to impact safety are sufficiently addressed by LCOs, and since the associated design features would not significantly affect safety, if altered in accordance with 10 CFR 50.59, the criterion of 10 CFR 50.36(c)(4) for including the above design features in the TS is not met.

The above relocated requirements related to design features are not required to be in the TS under 10 CFR 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. In addition, the NRC staff finds that sufficient regulatory controls exist under 10 CFR 50.59. Accordingly, the NRC staff concludes that these requirements may be relocated from the TS to the licensee's TS Bases or to the UFSAR, as applicable.

3.4.3 More Restrictive Requirements

By electing to implement the specifications of NUREG-1431, Section 4.0, the licensee adopted the following conditions that are more restrictive than those required by the existing TS:

1. Existing TS 5.4 Bases include a SFP fuel storage capacity limit, but do not include a description of the spent fuel drainage design used to prevent inadvertent drainage of the pool. In adopting NUREG-1431 guidance for fuel storage, the licensee added the existing TS Bases capacity discussion, which specifies a limit of 1016 fuel assemblies based on the heat removal capability of the SFP cooling system. SFP design limits are discussed in UFSAR Section 9.1. The lower suction line penetrates the spent fuel pool approximately 5 ft-4 in. above the top of fuel to preclude the possibility of pool drainage, and to ensure a minimum water level of 5 ft-4 in. above the top of the fuel.

The NRC staff reviewed the above more restrictive requirements, and concludes that they enhance the improved TS.

3.4.4 Less Restrictive Requirements

In electing to implement the specifications of NUREG-1434, Section 4.0, the licensee proposed the following requirements that are less restrictive than those required by the existing TS:

1. The existing TS 5.3.1.b discussion of the fuel delivered before and after January 1, 1984, presents information that is provided in the improved TS requirement (specification 4.3.1.1.a) of a "maximum" enrichment. That is, the fuel handling accidents for the new fuel pool (with respect to criticality concerns) have been performed assuming that the fuel pool is arranged with fuel of the maximum enrichment limit. Therefore, this additional discussion of fuel enrichment is no longer required to be specified.

2. Existing TS 5.4.2 includes a description of the fuel storage design features. The changes to these features are based on a revised criticality analysis supporting the proposed 18-month fuel cycle. The description of these features follows the standard guidance of NUREG-1431 (including the amount, kind, and source of special nuclear material) with the exception that the licensee did not add nominal center-to-center spacing between the fuel assemblies.

The NRC staff reviewed these less restrictive requirements and finds them to be acceptable, because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with existing licensing practices, operating experience, and plant accident and transient analyses, and provide reasonable assurance that the public health and safety will be protected.

3.5 Administrative Controls

3.5.1 Administrative Changes

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed administrative changes to the existing TS to bring them into conformance with NUREG-1431. The significant changes are as follows:

1. Existing TS 3.15.1.3 contains a requirement for a Low-Temperature Overpressure Protection (LTOP) Special Report concerning use of the LTOP system to mitigate an RCS or RHR pressure transient in accordance with specification 6.9.2. The Special Report is required to include documentation of all challenges to the pressurizer power-operated relief valves (PORVs) or RCS vent(s). It must also describe the circumstances initiating the transient, the effect of the PORVs or vent(s) on the transient, and any other corrective action. These requirements are detailed in improved TS 5.6.4, "Monthly Operating Reports," and are included in the licensee event report (LER) requirements to report an RCS pressure transient that exceeds expected values or is caused by unexpected factors.

2. The licensee revised existing TS 4.5.2.3.6.a test requirements to clarify that two separate tests are performed. A high-efficiency particulate air (HEPA) filter test and a charcoal adsorber bank test are separately performed, with each requiring a limit of less than 3 inches of water. Existing TS 4.5.2.3.6.a requires that the pressure drop across the combined HEPA filters and charcoal filters be less than 6 inches of water. Improved TS 5.5.10.c.1 and 5.5.10.c.3 limit the pressure drop to less than 3 inches for the HEPA and charcoal filters, respectively. Therefore, the total pressure drop remains less than 6 inches, but the location of the pressure drop is limited. This is essentially equivalent to a combined test of less than 6 inches of water, and is consistent with specified testing standards. The existing testing procedures

test the pressure drop across the HEPA and charcoal filters separately in plant procedures.

3. The licensee modified the inservice testing program description in existing TS 5.7.2.12 to include high-energy piping outside containment and steam generator tubes. This is consistent with the Ginna existing licensing bases and approved IST program.

4. Existing TS 4.11.1.1.a, 4.11.1.1.b, and 4.11.1.1.c provide charcoal adsorber system testing requirements. The licensee moved these requirements to the ventilation filter testing program (VFTP) described in the Administrative Controls (TS 5.5.10).

5. The technical content of several existing TS requirements is being relocated from other existing TS sections to the Administrative Controls section. These requirements are to become programs in the improved TS. A statement of applicability of improved TS SR 3.0.2 or SR 3.0.3 is needed in those new programs to maintain the existing allowances for surveillance frequency extensions, since these SRs are not normally applied to frequencies identified in the Administrative Controls section of the TS. The following improved TS programs incorporate this change:

Improved TS	Title
5.5.6	Pre-Stressed Concrete Containment Tendon Surveillance Program
5.5.7	Inservice Testing Program
5.5.10	Ventilation Filter Testing Program
5.5.11	Explosive Gas and Storage Tank Radioactivity Monitoring Program
5.5.15	Containment Leakage Rate Testing Program

Since this change maintains existing requirements within the improved TS, it is considered an administrative change, and is acceptable.

6. Existing TS 6.9.1.5 requires an annual report on challenges to the pressurizer relief and safety valves. Existing TS 6.9.1.2 requires the same information on a monthly basis. The improved TS deletes the annual report requirement, but retains the monthly reporting requirement on the valves. Since the details of the required reporting are unchanged, this is only a change in when the report is to be submitted and thus, is considered an administrative change and is acceptable.

7. NUREG-1431 Specification 5.5, "Explosive Gas and Storage Tank Radioactivity Monitoring Program," specifies the requirements and limits for the waste gas decay tanks. The licensee modified the requirements in improved TS 5.5.11 by changing the references and requirements that do not apply to the existing plant design (including deleting NUREG-1431 Specification 5.5.8.c). Since these

requirements result in the same limits as the existing requirements, the changes are purely administrative and are therefore acceptable.

8. NUREG-1431 Specification 5.5.13, "Diesel Fuel Oil Testing Program," specifies the requirements, standards, and limits to be followed in testing and maintaining quality diesel generator fuel oil. The licensee modified the requirements, standards, and limits in improved TS 5.5.13 to reflect the expected practices given in the NUREG guidance in place of existing TS 6.6.1.d. These requirements includes changes to test fuel oil prior to its addition to storage tanks in place of the periodic 92-day surveillance test. This testing regimen maintains a higher fuel oil purity standard since it is unlikely that important fuel oil properties will change in the 3-month period that the fuel oil is consumed for testing. These changes are therefore acceptable.

9. NUREG-1431 Specification 5.6.6, "RCS PTLR," specifies the analytical methods to be used to determine the RCS pressure and temperature limits, and specifies that these limits for the reactor pressure vessel and RCS shall be documented in a report maintained outside of TS. The licensee has elected to retain this information within the Administrative Controls TS reporting requirements. Thus, the pressure and temperature limits and curves specified in existing TS 3.1.2.1.a, Figures 3.1-1 and 3.1-2, will be included in improved TS Section 5.6.6. Since the existing requirements are retained, the improved TS is acceptable.

10. Existing TS 6.2.2.d requires that an individual qualified in radiation protection procedures must be onsite when fuel is in the reactor. Improved TS 5.2.2.c specifies that the radiation protection individual is limited to a 2-hour absence. Existing Ginna procedures for shift crew composition also limit the time the qualified radiation protection individual is allowed to be absent. Since these requirements result in essentially the same limits as the existing requirements, the changes are purely administrative and are therefore acceptable.

11. Existing TS 6.15.1.b specifies the approval process for ODCM changes. The licensee revised this specification to clarify that the effective changes are required to be approved by the Plant Manager instead of the onsite review function. Since the onsite review function reports to the Plant Manager, this is a restatement of existing TS requirements.

12. Existing TS 4.2.1 for the ISI references the "Ginna Station QA Manual." This document was renamed "Nuclear Policy Manual" in response to a Region II concern. Conforming changes were made to improved TS document references.

Improved TS	Existing TS	Program
5.5.1	6.15, 6.8.1.d	Offsite Dose Calculation Manual
5.5.2	4.4.3	Primary Coolant Sources Outside Containment
5.5.3	New	Post-Accident Sampling Program
5.5.4	3.9 & 3.16	Radioactive Effluent Controls Program
5.5.5	New	Component Cyclic or Transient Limit
5.5.6	4.4.4	Pre-Stressed Concrete Containment Tendon Surveillance Program
5.5.8	4.2	Inservice Testing Program
5.5.9	4.2	Steam Generator (SG) Tube Surveillance Program
5.5.10	4.5.2.3 & 4.11.1	Ventilation Filter Testing Program
5.5.11	3.9.2.5 & 3.9.2.6	Explosive Gas and Storage Tank Radioactive Monitoring Program
5.5.12	4.6.1.d	Diesel Fuel Oil Testing Program
5.5.13	New	Technical Specification Bases Control
5.5.14	New	Safety Function Determination Program

13. The licensee proposed to incorporate programmatic controls for radioactive effluents and radiological environmental monitoring TS in Specifications 5.5 of the improved TS, in accordance with the guidance in GL 89-01, as modified by NUREG-1431. The programmatic controls ensure that programs are established, implemented, and maintained to ensure that operating procedures are provided to control radioactive effluents consistent with the requirements of 10 CFR 20.1302; 40 CFR Part 190; 10 CFR 50.36a; and 10 CFR Part 50, Appendix I.

These changes are considered to be a purely administrative relocation of the requirements in the improved TS, and are therefore acceptable.

3.5.2 Radiological Effluent Technical Specifications

3.5.2.1 TS Relocated Within the Improved TS

In accordance with the guidance in NUREG-1431, the licensee proposed to relocate all or portions of the following existing TS within the improved TS:

Existing TS	Title
3.9.2.5	Explosive Gas Mixture
3.9.2.6	Waste Gas Decay Tanks

1. The purpose of existing TS 3.9.2.5 is to limit the potential for creating an explosive mixture of oxygen in a gas decay tank and the quantity of radioactivity contained in each waste gas decay tank.

The intent of the limit is to minimize the potential for a gross rupture of the system which would, in turn, result in an uncontrolled release of radioactivity. In the event of an explosion resulting in rupture of the system, the radioactivity limit ensures that radiological standards for the public are not exceeded. Improved TS 5.5.11, "Explosive Gas and Storage Tank Radioactivity Monitoring Program," provides a surveillance program to monitor and maintain the concentration of oxygen in the system to within limits established in the program.

2. The purpose of TS 3.9.2.6 is to limit the quantity of radioactivity in each waste gas decay tank. The tanks listed in this specification include the gas decay tanks located in the Auxiliary Building. Restricting the quantity of radioactive material contained in specified tanks ensures that, in the event of an uncontrolled release of the tank's contents, the resulting concentrations at the exclusion area boundary would result in a total body exposure to an individual of equal to or less than 0.5 rem (UFSAR 15.7.1). The improved TS address this limit within Specification 5.5.11, "Explosive Gas and Storage Tank Radioactivity Monitoring Program," by providing a TS administrative control limiting the amount of activity contained within specified tanks.

3. Existing TS requirements for safety limits are relocated to Section 2.0 of the improved TS. Any changes to the existing TS requirements are discussed in Section 2.0 of this SE.

These changes are considered to be a purely administrative relocation of the requirements in the improved TS, and are therefore acceptable.

3.5.2.2 TS Relocated To Licensee-Controlled Documents

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate or reorganize all or portions of the following existing TS concerning radioactive effluent monitoring and treatment systems to licensee-controlled documents:

Existing TS	Title
3.5.5	Radioactive Effluent Monitoring Instrumentation
3.9.1.1	Liquid Effluents Concentration
3.16	Radiological Environmental Monitoring
Table 4.1-1	Instrumentation
4.10	Radiological Environmental Monitoring Surveillance Requirements
4.13	Radioactive Material Source Leakage Test
6.9.1.3	Annual Radiological Environmental Operating Report
6.9.1.4	Radioactive Effluent Release Report
Table 6.9-1	Environmental Radiological Monitoring Program Summary

Table 6.9-2 Reporting Levels for Radioactivity Concentrations in Environmental Samples

1. Existing TS 3.16.1 and Table 3.16-1 for the radiological environmental program require measurements of radiation and radioactive materials in exposure pathways, as well as measurement of specified radionuclides leading to the highest potential radiation exposures for members of the public. Table 4.1-1, Units #18, 28 and 29 provide surveillance requirements for this instrumentation. The programmatic requirements specified in the existing TS have been relocated to the ODCM and the Radioactive Effluent Controls Program is described in new Specifications 5.5.1 and 5.5.4, respectively.

2. The requirements in existing TS 3.16.2 and existing TS SR 4.10.2 support the measurement of radiation and radioactive materials in those exposure pathways and for those radionuclides leading to the highest potential radiation exposures for members of the public, utilizing land use census measurement. The programmatic requirements specified in the existing TS have been relocated to the ODCM and the Radioactive Effluent Controls Program described in new Specifications 5.5.1 and 5.5.4, respectively.

3. The requirements in existing TS 3.16.3 and existing TS SR 4.10.3 confirm the accuracy of the measurements of radiation and radioactive materials in specified exposure pathways and for those radionuclides leading to the highest potential radiation exposures for members of the public. The programmatic requirements specified in the existing TS have been relocated to the ODCM and the Radioactive Effluent Controls Program described in new Specifications 5.5.1 and 5.5.4, respectively.

4. Existing TS 4.13 applies to the test for leakage of radioactive material sources performed by the licensee. The source leak test is used to ascertain that any leakage from radioactive material sources is sufficiently low. The programmatic and procedural requirements specified in the existing TS have been relocated to the ODCM and the Radioactive Effluent Controls Program described in Specifications 5.5.1 and 5.5.4.

5. As part of the conversion to the improved TS, the licensee proposed to incorporate programmatic controls for radioactive effluents and radiological environmental monitoring in the Administrative Controls section of the improved TS. This proposed change is consistent with the requirements of 10 CFR Part 20, Appendix B, Table 2, Columns 1 and 2; 10 CFR 20.1302; 40 CFR Part 141; 40 CFR Part 190; and 10 CFR Part 50, Appendix I. At the same time, the licensee proposed to transfer the procedural details from the plant effluents TS to the ODCM or to the Process Control Program for solid radioactive wastes, as appropriate. These changes simplified the specifications related to radioactive effluents requirements.

The licensee's proposed changes to the TS are in accordance with the guidance in Generic Letter 89-01, as modified by NUREG-1431.

The licensee confirmed that the detailed procedural requirements addressing LCOs and their applicability, remedial actions, associated surveillance requirements, or reporting requirements for the specifications will be prepared and inserted in the ODCM and Process Control Program (PCP). Changes to these procedures will be made in accordance with administrative controls in the improved TS concerning changes to the ODCM, and in accordance with the controls associated with changes to the PCP, to be implemented in the ODCM or PCP when this amendment is issued. Changes to the ODCM and PCP will be documented and retained for the duration of the operating license in accordance with Specification 5.5.1 and plant procedures.

6. Existing TS 3.5.5 and Table 3.5-5 include requirements for radioactive effluent monitoring instrumentation. The licensee did not add requirements for radioactive effluent monitoring instrumentation which ensures that the limits of existing TS 3.9.1.1 and TS 3.9.2.1 for plant liquid and gaseous effluents are not exceeded. No screening criteria apply for these requirements, since the monitored parameters are not part of the primary success path in the mitigation of a DBA or transient. Further, these monitors are not used for, nor capable of, detecting a significant abnormal degradation of the reactor coolant pressure boundary before a DBA. Therefore, the requirements specified for this function do not satisfy the Commission's Final Policy Statement TS screening criteria, and are relocated to the ODCM and the Effluent Controls Program described in new Specifications 5.5.1 and 5.5.4, respectively.

7. The requirements in existing TS 6.9.1.3 and TS 6.9.1.4, and in Tables 6.9-1 and 6.9-2 are relocated to the ODCM and the Radioactive Effluent Controls Program in new Specifications 5.5.1 and 5.5.4. The procedural details and methods for obtaining summary effluent release information under the programmatic requirements established by 10 CFR Part 50, Appendix I, Section IV.B, and 10 CFR 50.36a can be sufficiently controlled in plant procedures.

8. The licensee proposed to replace existing TS 6.1.1.1, plant-specific management position titles, with generic titles. Personnel who fulfill these positions are required to meet specific qualifications as detailed in improved TS 5.3. Compliance details relating to the plant-specific management position titles are identified in licensee-controlled documents. The three major replacements are (a) the generic "Plant Manager" for the manager-level individual responsible for the overall safe operation of the plant, (b) the corporate vice president in place of the Vice President, and the "radiation protection technicians" in place of

existing TS titles, "Radiation Protection" personnel and "Qualified Health physicist." The plant-specific titles fulfilling the duties of these generic positions will continue to be defined, established, documented and updated in the UFSAR in accordance with improved TS 5.2.1. Therefore changes to these titles remain under the control of 10 CFR 50.59. This change does not eliminate any of the qualifications, responsibilities, or requirements for these personnel or their positions.

On the basis of the above, the NRC staff finds that the changes included in the proposed TS amendments are consistent with the guidance provided in GL 89-01, as modified by NUREG-1431. Further, they are not required to be in the TS under 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. Because the control of radioactive effluents continues to be limited in accordance with operating procedures that must satisfy the regulatory requirements of 10 CFR 20.106, 40 CFR Part 190, 10 CFR 50.36a, and Appendix I to 10 CFR Part 50, the NRC staff finds that sufficient regulatory controls exist under the regulations. Therefore, the NRC staff concludes that these requirements may be relocated from the TS to the ODCM and PCP. Accordingly, the NRC staff finds the proposed changes acceptable.

3.5.2.3 Other Relocated Requirements

In accordance with the guidance in the Commission's Final Policy Statement, the licensee proposed to relocate or reorganize all or portions of the following existing TS to licensee-controlled documents:

Existing TS	Title
3.13	Snubbers
3.16.1	Radiological Environmental Monitoring Program
4.2	Inservice Inspection
4.4.3	Recirculation Heat Removal System
4.4.4	Tendon Surveillance
4.5.2.3	Air Filtration System
4.11	Refueling
4.14	Snubber Surveillance Requirements
6.4	Training
6.8.1.e	Procedures - Process Control Program Implementation
6.9.1.1	Startup Reports
6.9.1.2	Monthly Operating Report
6.16	Process Control Program (PCP)
6.17	Major Changes to Radioactive Waste Treatment Systems (Liquid, Gaseous and Solid)

The more significant changes resulting from these relocated items are as follows:

1. Existing TS 3.13, "Snubbers," states that all snubbers shall be operable. Snubbers are passive devices used to support piping

systems, and the associated TS action statement requires inoperable snubbers to be replaced or repaired within 72 hours. In addition, a functional test failure analysis (per existing TS 4.14.1f) is required on the supported component or the component is required to be declared inoperable. The existing TS 4.14 (which incorporates existing TS 4.2.1.7 for inspection intervals by reference) and TS 4.2 surveillance requirements will be periodically examined under the inservice inspection program. The programmatic requirements specified in the existing TS have been relocated to the ISI Program, and any changes must be made in accordance with 10 CFR 50.55a.

2. Existing TS 4.2.1.1, 4.2.1.2, 4.2.1.3, and 4.2.1.5 establish requirements for the Inservice Inspection Program, including Quality Groups A, B, and C components, high-energy piping outside of containment, and snubbers. The proposed text relates to the ISI Program defined in 10 CFR 50.55a(g). The inspection interval for the Inservice Pump and Valve Testing Program in existing TS 4.2.1.6 relates to the IST program defined in 10 CFR 50.55a(f). The programmatic requirements specified in the existing TS have been relocated to the Ginna Nuclear Policy Manual (i.e., ISI Program), and any changes must be made in accordance with 10 CFR 50.55a.

3. Existing TS 4.4.4 specifies the minimum tendon sample population, testing frequency, and acceptance criteria for tendon stress surveillances. The procedural details for the existing TS 4.4.4 are being relocated to the Pre-Stressed Concrete Containment Tendon Surveillance Program (improved TS 5.5.6). Therefore, procedural requirements will be relocated to plant procedures and controlled in accordance with 10 CFR 50.59.

4. Existing TS 4.4.3 contains specific criteria for testing pressure, acceptance criteria, correction actions, and test frequencies for systems that can contain containment sump fluid during the recirculation phase of an accident. These criteria are being relocated to improved TS 5.5.2, which specifies the systems subject to this testing and requires "preventative maintenance and periodic visual inspections" and leak tests "at refueling cycle intervals or less." The programmatic requirements specified in the existing TS have been retained in the Primary Coolant Sources Outside Containment Program described in new Specification 5.5.2. The specific testing pressure, acceptance criteria, and corrective actions will be contained in plant procedures implementing improved TS 5.5.2. Procedural requirements relocated to plant procedures will be controlled in accordance with 10 CFR 50.59.

5. Existing TS 4.5.2.3 and 4.11.1 air filtration system surveillance requirements denote the frequency, methods, and conditions of the air filtration system tests. These requirements are moved to the ventilation filter testing program (VFTP) described in new Specification 5.5.10, which specifically references RG 1.52,

Revision 2. Sections 5.b and 5.c of RG 1.52 contain the same testing frequencies specified in existing TS 4.5.2.3.1, 4.5.2.3.2, 4.5.2.3.3, 4.5.2.3.4, 4.5.2.3.6, 4.5.2.3.7, 4.5.2.3.8, 4.11.1.1 and 4.11.1.2. The methyl iodide test requirements in existing TS 4.5.2.3.1.c, 4.5.2.3.6.d and 4.11.1.1.c and other procedural requirements will be relocated to plant procedures and controlled in accordance with 10 CFR 50.59.

6. The licensee proposed that the training requirements of existing TS 6.4 be relocated to the UFSAR. Existing TS 6.4.1 requires retraining and replacement training programs for the facility staff. Further, existing TS 6.4.1 specifies that these programs must meet the requirements of ANSI N18.1-1971 and Appendix A to 10 CFR Part 55. The training program standard defined by the National Fire Protection Association (NFPA) No. 27, 1975 Section 40, and stated exceptions are specified in existing TS 6.4.2. Training and requalification of those positions are as specified in 10 CFR Part 55. The licensee proposed to relocate these provisions to the UFSAR, as previously described. The NRC staff concludes that the control of these provisions by 10 CFR 50.59 is sufficient, and removing them from the TS is acceptable.

7. The licensee proposes to relocate the implementation requirements of existing TS 6.8.1.e and the PCP description in existing TS 6.16 to the TRM. The PCP (described in the UFSAR) implements the requirements of 10 CFR Part 20, Part 61, and Part 71. Relocating the description of the PCP does not affect the safe operation of the facility. The NRC staff concludes that the regulatory controls in 10 CFR 50.59 for changes to the UFSAR and the TRM provide sufficient control of these requirements, and removing these provisions from the TS is acceptable.

8. The requirements in existing TS 6.9.1.1 to submit a startup report have been relocated to the UFSAR. The report was a summary of plant startup and power escalation testing following receipt of the operating license; an increase in licensed power level; the installation of nuclear fuel with a different design or manufacturer than the existing fuel; and modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the facility. The report provides a mechanism for the NRC staff to review the appropriateness of licensee activities after-the-fact, but contains no requirement for NRC staff approval. Inasmuch as this report was required to be provided to the NRC staff within 90 days following completion of the respective milestones, all of which have already occurred, the removal of this requirement is acceptable.

9. The monthly operating report contains routine operating statistics and shutdown experience that are submitted in accordance with 10 CFR 50.4. In addition, consistent with the NRC staff guidance in NUREG-1431, the licensee proposed to include documentation of all

challenges to the pressurizer PORVs or safety valves in this report. The existing TS 6.9.1.2 requirements (to include a narrative summary of operating experience describing the operation of the facility including major safety-related maintenance for the month) essentially requires a less useful generalized discussion that has been relocated to plant procedures.

10. The licensee proposed to relocate existing TS 6.17 requirements to use the Radioactive Effluent Release Report to notify the Commission of major changes made to radioactive waste system equipment, components, and structures, and radwaste treatment system design that could (a) alter characteristics or quantities of effluents released, or (b) invalidate the accident analysis. Changes to these systems are controlled in existing TS 6.17.2.1.a by 10 CFR 50.59. Commission notification of significant changes to these systems is addressed by 10 CFR 50.59(b)(2). In addition, licensee procedure CHA-RETS-REP-ANNUAL contains the requirement to document major changes to the radioactive waste treatment system in the annual Radioactive Effluent Release Report (improved TS 5.6.3). Therefore, relocation of these reporting requirements to the plant procedures implementing improved TS 5.6.3 is acceptable.

11. The Radiological Environmental Monitoring Program (existing TS 3.16.1) requires monitoring the radiation and radionuclides in the environs of Ginna consistent with the guidance specified in 10 CFR Part 50, Appendix I. This program ensures that radioactive effluents are restricted to levels as low as reasonably achievable, and have no impact on plant nuclear safety. The details and description of the program are already contained in the ODCM and improved TS 5.5.1. The NRC staff concludes that these regulatory requirements, and 10 CFR 50.59 for changes to the UFSAR, provide sufficient control of these provisions and removing them from the TS is acceptable.

The above relocated requirements relating to administrative controls are not required to be in the TS under 10 CFR 50.36, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. In addition, the NRC staff finds that sufficient regulatory controls exist under 10 CFR 50.59 and 10 CFR 50.54 and the other regulations set forth above. Accordingly, the NRC staff concludes that these requirements may be relocated from the TS to the licensee's ISI program, UFSAR, TRM, or plant procedures, as applicable.

3.5.3 More Restrictive Requirements

By electing to implement the specifications of NUREG-1431, Section 5.0, the licensee has adopted a number of conditions that are more restrictive than those required by the existing TS. The more significant conditions are as follows:

1. The licensee proposed to revise existing TS 6.1 to include a requirement that the Plant Manager shall approve each proposed test, experiment, or modification to structures, systems, or components that affect nuclear safety. In addition, the licensee proposed to include the requirements of NUREG-1431 TS 5.1.2, which establish Shift Supervisor control room command responsibilities.

2. The licensee adopted the Radioactive Effluents Control Program (improved TS 5.5.4), Containment Leak Rate Testing Program (improved TS 5.5.15), Core Operating Limits Report (COLR) (improved TS 5.6.5), RCS Pressure and Temperature Limits Report (improved TS 5.6.6), Technical Specification Bases Control Program (improved TS 5.5.13), and Safety Function Determination Program (improved TS 5.5.14). These TS represent five conditions more restrictive than required by the existing TS.

   The Radioactive Effluent Controls Program is included to support the relocation of the radiological environmental monitoring TS, consistent with GL 89-01 and the changes to 10 CFR Part 20. The COLR documents NRC staff-approved methods for determining the core operating limits for each reload cycle. The PTLR establishes analytical methods reviewed and approved by the NRC staff, which are used to determine changes to the RCS pressure and temperature limits. Additionally, the PTLR sets forth requirements to establish and document specified RCS pressure and temperature limits and PORV lift settings required to support the low-temperature overpressure protection system. The Safety Function Determination Program is included to support implementation of the support system operability characteristics of the improved TS. The Bases Control Program is provided to specifically delineate the appropriate methods and reviews necessary for a change to the improved TS Bases.

3. The licensee proposed a requirement in improved TS 5.4.1.b to maintain Emergency Operating Procedures (EOPs), as implemented in response to NUREG-0737. Although EOPs are included as a necessary procedure in Regulatory Guide 1.33, the existing TS do not include the additional procedures and changes made in response to the guidance in NUREG-0737 and Supplement 1 thereto. This change ensures that these commitments are maintained, and that the guidance and commitments are appropriately considered for any changes to these procedures.

4. The licensee proposed to include the requirement that the plant operations manager or operation middle manager shall hold an SRO license. The NRC staff reviewed this requirement, and finds it to be acceptable and consistent with the requirements of Regulatory Guide 1.8, Revision 2, and ANSI N18.1-1971.

5. The improved TS modify existing TS 6.9.1.4 to include a report submittal date for the Radioactive Effluent Release Report to be

provided consistent with the submittal date for related reports (e.g., the Annual Radiological Environmental Operating Report).

The NRC staff reviewed the above more restrictive requirements, and concludes that they enhance the improved TS. Therefore, the more restrictive requirements are acceptable.

3.5.4 Less Restrictive Requirements

In electing to implement Section 5.0 Specifications of NUREG-1431, the licensee proposed a number of conditions that are less restrictive than those allowed by the existing TS.

1. The licensee proposed to change the existing TS 4.4.3 frequency for testing the RHR system in the recirculation configuration from every 12 months to "refueling cycle intervals or less" in improved TS 5.5.2. The improved TS includes a change in the fuel cycle length from 18 months to 24 months, as well as corresponding changes in the RHR system recirculation configuration test, since these test intervals are based on fuel cycle length. The increased time between surveillances is acceptable, since the affected systems are normally filled with water, and leakage through these systems would be detected by operator walkdowns and during quarterly inservice testing of system pumps. Additionally, scheduling TS testing that removes the RHR system from operation more frequently than a refueling interval would result in a TS-required plant shutdown because of the loss of safety systems. Therefore, this increased surveillance interval is considered acceptable.

2. Existing TS surveillance 4.6.1.d specifies a 92-day test to verify the limits of American Society for Testing and Materials (ASTM) D975-78, Table 1, for diesel fuel oil viscosity, water, and sediment testing are met. The diesel fuel oil test requirements are moved to new TS 5.5.12, and the licensee proposes to identify the requirements as a "program" consistent with the format of NUREG-1431. The new fuel oil will be tested prior to addition for specific gravity, flash point, kinematic viscosity, and proper color. Within 31 days following addition, the properties of the new fuel oil will be tested to verify the ASTM 2D fuel oil limits, other than those above, are met. This is acceptable because onsite fuel oil is consumed in routine diesel start testing and must be replenished every 92 days. The staff has determined that unacceptable fuel will be identified by testing prior to its addition to fuel storage tanks. The 31 day test is sufficient to be assured the fuel remains acceptable.

3. Existing TS 6.9.2.1 specifies reporting requirements if leak testing of sealed sources indicates leakage equal to or greater than 0.005 microcuries of removable contamination. The licensee did not add this reporting requirement related to sealed sources,

since this is specified in 10 CFR 30.50. Ginna procedure HP-8.2 contains the leak testing requirements for sealed sources. The requirement for Commission notification is contained in plant procedure CHA-RETS-REP-ANNUAL.

4. Existing TS 6.9.2.4 requires that the Commission be notified of reactor overpressure protection events. The licensee proposed that this requirement not be retained in the TS. The licensee is required by 10 CFR 50.73(a)(2) to submit an LER for all reportable events specified in 10 CFR 50.73. The reports are required to be submitted within 30 days, and must contain the same type of information required by existing TS 6.9.2.4. The above requirements are included in licensee procedures, which implement 10 CFR 50.72 and 10 CFR 50.73. The NRC staff concludes that these regulatory requirements provide sufficient control of these provisions, and removing them from the TS is acceptable.

The NRC Staff reviewed the above less restrictive requirements and finds that they are acceptable because they do not present a significant safety question in the operation of the plant. The TS requirements that remain are consistent with existing licensing practices, operating experience, and plant accident and transient analyses, and provide reasonable assurance that the public health and safety will be protected.

4.0 EVALUATION OF OTHER CHANGES INCLUDED IN THE APPLICATION FOR CONVERSION TO IMPROVED TECHNICAL SPECIFICATIONS

4.1 Core Operating Limits Report

The licensee proposed changes to modify specifications having cycle-specific parameter limits by replacing the values of those limits with a reference to a Core Operating Limits Report (COLR) for the values of those limits. The proposed changes also include the addition of the COLR to the definition section of the TS. Guidance on the proposed changes was developed by NRC and provided to all power reactor licensees and applicants by Generic Letter (GL) 88-16, dated October 4, 1988.

The proposed changes to the TS are in accordance with the guidance provided by GL 88-16 and are addressed below.

1. The definition section of the TS was modified to include a definition of the COLR that requires cycle/reload-specific parameter limits to be established on a unit-specific basis in accordance with NRC-approved methodologies that maintain the limits of the safety analysis. The definition notes that plant operation within these limits is addressed by individual specifications.

2. The following specifications were revised to replace the values of cycle-specific parameter limits with reference to the COLR that provides these limits.

a. Specification 3.1.1
The shutdown margin limits for this specification are specified in the COLR.

b. Specification 3.1.3
The moderator temperature coefficient (MTC) limits for this specification are specified in the COLR.

c. Specification 3.1.5
The shutdown bank insertion limits for this specification are specified in the COLR.

d. Specification 3.1.6
The control bank insertion limits for this specification are specified in the COLR.

e. Specification 3.2.1
The heat flux hot channel factor limit for this specification is specified in the COLR.

f. Specification 3.2.2
The nuclear enthalpy rise hot channel factor limits for this specification are specified in the COLR.

i. Specification 3.2.5
The axial flux difference limits for this specification are specified in the COLR.

j. Specification 3.9.1
The boron concentration of the RCS and the refueling canal for this specification are specified in the COLR.

The Bases of affected specifications have been modified by the licensee to include appropriate reference to the COLR. With the exception of a portion of Specification 3.4.1, these limits have been relocated in accordance with NUREG-1431, Revision 1. RG&E currently does not have an LCO for departure from nucleate boiling (DNB) parameters (those in Specification 3.4.1); these cycle-specific parameters for the pressurizer pressure, the RCS average temperature and RCS total flow rate limits, have been added to Ginna's COLR. These parameters will change as a result of the replacement of steam generators and the conversion to 18-month cycles in 1996. The average temperature and possibly the pressurizer pressure will change cycle to cycle. These parameters will be calculated using previously approved methodologies. Based on our review, we conclude that the changes to these specifications and their respective Bases are acceptable.

3. Specification 5.6.5 has been revised to include the COLR under the reporting requirements of the Administrative Control section of the TS. This section requires that the COLR be submitted, upon issuance, to the NRC. The report provides the values of cycle-specific parameter limits that are applicable for the current fuel cycle. Furthermore, this specification requires that the NRC-approved methodologies be used in establishing the values of these limits for the relevant specifications and that the values be consistent with all applicable limits of the safety analysis. The approved methodologies are the following:

a. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.
(Methodology for LCO 3.1.1, LCO 3.1.3, LCO 3.1.5, LCO 3.1.6, LCO 3.2.1, LCO 3.2.2, LCO 3.2.3, and LCO 3.9.1)

b. WCAP-9220-P-A, "Westinghouse ECCS Evaluation Model-1981 Version," Revision 1, February 1982.
(Methodology for LCO 3.2.1)

c. WCAP-8385, "Power Distribution Control and Load Following Procedures - Topical Report," September 1974.
(Methodology for LCO 3.2.3.)

d. WCAP-8567-P-A, "Improved Thermal Design Procedure," February 1989.
(Methodology for LCO 3.4.1 when using ITDP)

e. WCAP 11397-P-A, "Revised Thermal Design Procedure," April 1989.
(Methodology for LCO 3.4.1 when using RTDP)

f. WCAP-10054-P-A and WCAP-10081, "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," August 1985.
(Methodology for LCO 3.2.1)

g. WCAP-10924-P-A, Volume 1, Rev. 1, and Addenda 1,2,3,"Westinghouse Large-Break LOCA Best-Estimate Methodology, Volume 1: Model Description and Validation," December 1988.
(Methodology for LCO 3.2.1)

h. WCAP-10924-P-A, Volume 2, Rev. 2, and Addenda, "Westinghouse Large-Break LOCA Best-Estimate Methodology, Volume 2: Application to Two-Loop PWRs Equipped with Upper Plenum Injection," December 1988.
(Methodology for LCO 3.2.1)

i. WCAP-10924-P-A, Rev. 2 and WCAP-12071, Westinghouse Large-Break LOCA Best Estimate Methodology, Volume 2: Application to Two-Loop PWRs Equipped With Upper Plenum Injection, Addendum 1: Responses to NRC Questions," December 1988.
(Methodology for LCO 3.2.1)

j. WCAP-10924-P, Volume 1, Rev 1, Addendum 4, "Westinghouse LBLOCA Best Estimate Methodology: Model Description and Validation: Model Revisions, " August 1990.
(Methodology for LCO 3.2.1)

Finally, the specification requires that all changes in cycle-specific parameter limits be documented in the COLR before each reload cycle or

remaining part of a reload cycle and submitted to NRC, prior to operation with the new parameter limits.

On the basis of this review, the NRC staff concludes that the licensee provided an acceptable response to the items in GL 88-16 on modifying cycle-specific parameter limits in the Ginna TS. Because plant operation continues to be limited in accordance with the values of cycle-specific parameter limits that are established using NRC-approved methodologies, the NRC staff concludes that this change has no impact on plant safety. Accordingly the NRC staff finds that the proposed changes are acceptable.

4.2 Evaluation of 24-Month Surveillance Intervals

Generic Letter (GL) 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," was published on April 2, 1991, in order to provide guidance for those facilities seeking to increase the duration of their fuel cycles. GL 91-04 contained three enclosures which outlined the information that needs to be included in license applications. Specifically, GL 91-04 included Enclosure 1, "Guidance on Preparation of a License Amendment Request for Changes in Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," Enclosure 2, "Guidance for Addressing the Effect of Increased Surveillance Intervals on Instrument Drift and Safety Analysis Assumptions," and Enclosure 3, "Guidance on Information Needed to Support an Exemption to Appendix J of 10 CFR Part 50 to Accommodate a 24-Month Fuel Cycle."

The licensee stated that Ginna will be going from a 12-month to an 18-month refueling cycle following their Spring 1996 outage. However, the licensee's submittal proposes a 24-month refueling cycle in order to provide greater flexibility for planning purposes, and would prevent the need for significant technical specification changes if Ginna were to change to a 24-month refueling cycle.

The licensee's Attachment H submittal is based on the three enclosures to GL 91-04. Section A discusses the technical specification changes which are required for this change; Section B provides an evaluation of instrument drift and safety analysis assumptions with respect to the increased surveillance intervals; and Section C provides an evaluation of 10 CFR Part 50, Appendix J requirements. In addition, the licensee has provided a Section D that discusses the impact of mechanical and electrical components.

4.2.1 Technical Specification Changes Required

By letter dated May 26, 1995, RG&E proposed revising the Ginna Technical Specifications by converting to the improved technical specifications, which include a change to the surveillance intervals based on fuel cycle lengths up to 24 months from the current 18-month cycle. These changes are identified in the improved TS submittal as "Attachment H". The following review covers the portions of Attachment H pertaining to steam generator inspection intervals, Specification 5.5.9, and reactor coolant system operational leakage, LCO 3.4.13.

4.2.1.1 Steam Generator (SG) Inspection Intervals (SR 3.4.13.2)

GL 91-04 specifies changes to several technical specifications to address increased surveillance intervals. The current Ginna TS and the proposed improved Ginna TS indicate that the inspection intervals for steam generator tubes shall be specified in the Ginna inservice inspection program. The inservice inspection program allows tube inspections to be performed on fuel cycle lengths of 24 months. Therefore, no changes to the TS are being requested in this area.

4.2.1.2 Reactor Coolant System Operational Leakage (LCO 3.4.13)

The proposed LCO 3.4.13 limits primary-to-secondary leakage to 0.1 gpm per steam generator averaged over 24 hours while in Modes 1, 2, 3, and 4 which is equivalent to 144 gallons per day. This is not significantly more than the GL 91-04 proposed 100 gallons per day for plant operation beyond 24 months after the previous tube inspection operation when the results of the two previous inspections are in the C-2 Category. The current Ginna TS require that primary-to-secondary leakage be limited to 0.1 gpm in any one steam generator. Therefore, no changes to the TS are being requested in this area.

4.2.2 Evaluation of Instrument Drift And Safety Analysis Assumptions

4.2.2.1 Introduction

The improved TSs include changes in the surveillance intervals to accommodate the 24-month fuel cycle, and with the 25% grace period, the instrument surveillance interval may be extended to a maximum interval of 30 months.

The licensee performed a study, "Evaluation of 24-Month Instrument Surveillance Intervals," DA-EE-95-0109, Revision 0, May 26, 1995, and generated a list of all instrumentation subject to the increased surveillance interval that is included in the license amendment.

4.2.2.2 Evaluation

The licensee study, DA-EE-95-0109, contained 489 instruments that were subject to drift consideration. From the 489 instruments, the licensee selected a sample of 191 instruments for further review of drift data based on the instrument model category. The review of drift data for the 191 instruments corresponds to about 40% of the total population of instruments included in the proposed increased surveillance interval.

Five years of drift data evaluated by the licensee, from 1990 to 1994, demonstrated acceptable drift for longer than the 30-month interval which would be permitted by the proposed TSs. The licensee stated that for a calibration interval of up to 30 months, the magnitude of instrument drift over an observed 36-month period was bounded by that assumed in the accident analyses.

For some instrument models, the licensee's sample of drift data included 100% of the population of those instrument types. The licensee determined that other than the TS change to a 24-month surveillance interval, no further TS changes were needed, and no safety analysis assumptions were changed.

The NRC staff has determined that the plant-specific instrument historical drift data adequately support the extension of instrument surveillance intervals to 24 months. The licensee has committed to monitor and assess the effects of the increased surveillance intervals to ensure that the instrument loops remain operable over the extended period between surveillances. The NRC staff considers the extension of surveillance intervals to accommodate the 24-month fuel cycle acceptable.

Based on the above, the NRC staff concludes that the licensee has demonstrated that instrument drift will be within acceptable limits over the proposed 24-month surveillance interval for those instruments covered by the TS change. In addition, the licensee has committed to a monitoring program of the effects of the increased surveillance interval to ensure that the instrument loops remain operable. The NRC staff, therefore, finds the licensee's request to increase the instrument surveillance interval from 12 months to 24 months to be acceptable.

4.2.3 Evaluation of Mechanical and Electrical Components

Generic Letter 91-04 requires consideration of the surveillance interval change and the effect on safety for items other than instrumentation. The following three categories of mechanical and electrical components were evaluated for the surveillance interval change by the licensee.

4.2.3.1 Verification of Pump and Valve Actuation Every 24 Months

Table 2 of the licensee's Attachment H identifies surveillance requirements for pumps and valves that receive an ESFAS signal. These surveillances verify that the pumps and valves will actuate to their correct position on a refueling outage basis. The licensee has stated that with the exception of the MSIVs, all components listed are tested in accordance with the Inservice Testing Program. Testing is typically conducted from the control room and verifies that the associated pumps and valves can actuate. The MSIVs are not tested while at power but are tested during each cold shutdown. In addition, the MSIVs are in series with non-return check valves which are given credit in the accident analysis for steam generator isolation.

The NRC staff, therefore, finds the licensee's request to increase the surveillance intervals identified in Appendix H from 12 months to 24 months to be acceptable.

4.2.3.2 Verification of Reactivity and Power Distribution Parameters

Surveillance Requirements 3.1.2.1, 3.1.3.1, 3.1.3.2, 3.1.4.4, 3.1.6.1 and 3.1.7.1 all deal with reactivity and power distribution parameters which are verified once per cycle or upon removal of the reactor vessel head. These surveillances, which are identified in Table 3 of the licensee's Attachment H, are performed in order to verify parameters that could have changed during the shutdown. Included are verification of the moderator temperature coefficient and core reactivity after each refueling as well as verification of the position of each rod and the scram time for each rod after each removal of the reactor head and critical control bank position each time criticality is achieved. These surveillances are then supplemented with additional periodic surveillances to ensure that the reactivity and power distribution parameters remain within the accident analysis assumptions. Increasing the fuel cycle length to 24 months will not have an adverse impact and thus is acceptable.

4.2.3.3 Miscellaneous Verifications

Table 4 of the licensee's Attachment H list miscellaneous verifications that do not fall into either of the above categories but whose frequency is based on fuel cycles.

Surveillance Requirements 3.3.1.11, 3.3.1.12, 3.3.2.4 and 3.3.5.4

Surveillance Requirements 3.3.1.11, 3.3.1.12, 3.3.2.4 and 3.3.5.4 reflect trip actuating device operational tests (TADOT) for ESFAS or RPS functions. The licensee states that Ginna has not observed any failures of these functions during previous testing and therefore, the increased surveillance interval is not expected to be of concern regarding component performance.

The licensee performed a review of plant records associated with tests conducted between January 1985 and January 1995, and the review did not indicate any failures of the subject components. In addition, a review of the Nuclear Plant Reliability Data System during this time frame did not indicate any failures either. Based on this information, the NRC staff finds the licensee's request to increase these surveillance intervals from 12 months to 24 months to be acceptable.

Surveillance Requirement 3.4.1.3

Surveillance Requirement 3.4.1.3 verifies that the reactor coolant system total flow rate is within limits as specified in the COLR. This surveillance requirement is new to the Ginna TSs. The proposed frequency of 24 months is reasonable and is a shorter frequency than previously existed. Thus the proposed SR 3.4.1.3 is acceptable.

Surveillance Requirements 3.6.2.2 and 3.6.7.1 and Specification 5.5.2

Surveillance Requirements 3.6.2.2 and 3.6.7.1 and Specification 5.5.2 are new to Ginna and represent an increase in requirements. SR 3.6.2.2 requires verification that only one door in each personnel air lock can be opened at a time whereas SR 3.6.7.1 requires that each hydrogen recombiner blower fan demonstrate operability by running for greater than five minutes. Specification 5.5.2 requires periodic leak tests for

primary coolant sources outside containment. Each of these requirements is consistent with NUREG-1431 and is acceptable.

Surveillance Requirement 3.7.4.1

Surveillance Requirement 3.7.4.1 requires performance of a complete cycle of each atmospheric relief valve. SR 3.7.4.1 is a new requirement in the Ginna TSs. The proposed frequency of 24 months is reasonable and is a shorter frequency than previously existed. Thus the proposed SR 3.7.4.1 is acceptable.

Surveillance Requirements 3.8.1.6, 3.8.1.7, 3.8.1.8 and 3.8.1.9

Existing TS surveillance requirements 4.6.3.b, 4.6.1.e.2, 4.6.1.e.3(a), 4.6.1.e.3(b) and 4.6.1.e.3(c) frequency of testing for offsite power and emergency diesel generator systems are increased from 18 months to 24 months. The proposed changes are intended to follow the guidance of GL 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate 24-Month Fuel Cycle."

After a preliminary review of the above TS change the NRC staff requested additional information in order to clarify the scope of maintenance history and surveillance records review which was conducted by the licensee. The licensee submitted the additional information by letter dated November 20, 1995, which clarifies the technical basis for the extension of the subject surveillance interval. The staff concludes that the change is acceptable.

Proposed Change to Existing TS Section 4.6.3.b

The licensee proposed to replace the existing TS SR 4.6.3.b with the improved TS SR 3.8.1.6. This SR involves the transfer of the 480 volt safeguards bus power supply from the preferred offsite power circuit configuration (50/50 mode) to the alternate offsite power configurations (100/0 mode and 0/100 mode) which demonstrates the operability of the alternate circuit distribution network to power the required loads. The staff concludes that the change is acceptable.

Proposed Change to Existing TS Sections 4.6.1.e.2, 4.6.1.e.3(a), 4.6.1.e.3(b) and 4.6.1.e.3(c)

The licensee proposed to replace the existing TS Surveillance Requirements 4.6.1.e.2, 4.6.1.e.3(c), 4.6.1.e.3(a), and 4.6.1.e.3(b) with improved TS SR 3.8.1.7, SR 3.8.1.8 and 3.8.1.9 respectively.

SR 3.8.1.7, which replaces existing TS SR 4.6.1.e.2, verifies that each emergency diesel generator (EDG) does not trip during and following a load rejection of 295 kW or greater. This SR demonstrates the EDG load response characteristics and capability to reject the largest single load on the buses which will be supplied by the EDG.

SR 3.8.1.8, which replaces existing TS SR 4.6.1.e.3(c), demonstrates that the EDG noncritical protective functions (e.g., overcurrent, reverse power, local stop pushbutton) are bypassed on an actual or stimulated safety injection (SI) actuation signal, and critical protective functions (e.g., engine overspeed, low lube oil pressure, and start failure (overcrank) relay) trip the EDG in order to avert substantial damage.

SR 3.8.1.9, which replaces existing TS SR 4.6.1.e.3(a) and SR 4.6.1.e.3(b), demonstrates the EDG operation during an actual or simulated loss of offsite power (LOP) signal in conjunction with an actual or simulated SI actuation signal. In the event of a design basis accident coincident with a LOP, the EDG is required to supply the necessary power to the engineered safety features systems so that the fuel, reactor coolant system, and containment design limits are not exceeded. Overall, the subject SR verifies proper load shedding of 480 volt safeguards buses and the start of each EDG on an actual or simulated LOP signal in conjunction with an SI signal.

In addition to the surveillance interval extension for the above surveillance requirements, Note (1) was added to the above surveillance requirements and Note (2) was added to SR 3.8.1.9 as shown below:

(1) All DG starts may be preceded by an engine prelube period.

(2) This Surveillance shall not be performed in Mode 1, 2, 3, 4.

Note 1 is intended to minimize the wear and tear on the EDGs during testing consistent with manufacturer recommendations. Note 2 is to advise operators that the performance of the specific surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state plant operation. The other change associated with the replacement of TS SR 4.6.1.e.3(c) with SR 3.8.1.9 includes the omission of maximum breaker closure times for all breakers and the breakers for a Train A and B equipment configuration (i.e., EDG plus SI pump plus Residual Heat Removal pump).

According to the proposed Bases for SR 3.8.1.6, SR 3.8.1.7, SR 3.8.1.8 and SR 3.8.1.9 the frequency of 24 months is based on engineering judgement, taking into consideration the plant conditions required to perform the surveillance and is intended to be consistent with the expected fuel cycle lengths. The licensee stated in its submittal dated November 20, 1995, that the components addressed by the subject surveillance requirements are included in the Ginna Reliability Centered Maintenance (RCM) program.

The Ginna EDGs are ALCO Model 351 generators which are manufactured by the Fairbanks Morse Corporation. The licensee participates in a Fairbanks Morse DG Working Group which formulates recommended preventive maintenance (PM) activities for these generators. The licensee stated that neither the manufacturer nor the working group have endorsed any testing requirements or testing frequencies for the subject DG equipment.

In addition, none of the subject PM activities are recommended on a frequency less than the proposed 24-month interval. Overall, the licensee asserts that all of the recommended PM activities are either incorporated or otherwise addressed in the DG RCM program.

The licensee states that the Ginna RCM program is a "living" program which uses the review of plant maintenance records, manufacturer recommendations, plant life extension reports and the importance of the component to implement PM activities. The licensee program also includes effectiveness monitoring mechanisms to ensure that the recommended PM activities continue to provide the necessary component reliability. After a review of the RCM program records of the subject surveillance requirement, the licensee determined that no component except the service water (SW) pump breakers required testing or PM related activities on a frequency less than 24 months.

The SW pump breakers, which are tested as a part of SR 3.8.1.9, are inspected every 12 months due to past reliability concerns. However, the above PM activities are performed at power since there are four SW pumps, of which only two pumps are required to meet TS requirements. Therefore, the licensee believes that an extension to 24-month for the subject surveillance requirements will not result in any increased failure rates especially since most components are also tested on a more frequent basis as a result of other testing requirements (e.g., monthly DG tests).

On the basis of its review of the above information, the NRC staff finds that the proposed TS changes are consistent with the guidance provided in GL 91-04. Further, the other changes represent administrative changes consistent with the STS format. The licensee has committed to implement the Maintenance Rule (10 CFR 50.65) beginning in 1996 which will require the monitoring and assessment of component performance in order to ensure adequate performance. Therefore, based upon the above information, the NRC staff finds the subject TS changes acceptable.

Specification 5.5.10

The proposed conversion to the improved TS contains a description of the ventilation filter testing program (VFTP) in newly proposed Item 5.5.10 under "Programs and Manuals" in the "Administrative Controls" (Section 5) of the ITS. The description includes a listing of the ventilation filter systems that have to be tested, identification of the tests that have to be performed on each of these filter systems, the regulatory document on which the test methods and frequencies will be based, and the acceptance criteria for these tests.

The proposed conversion to the improved TS includes a change in fuel cycle length from 18 to 24 months and corresponding changes in several surveillance test intervals from 18 to 24 months. Among the proposed changes to the surveillance test intervals are periodic verification of ventilation filter systems performance and periodic verification of automatic actuations of applicable ventilation filter systems on actual

or simulated actuation signals (newly proposed Surveillance Requirements (SRs) 3.6.6.11, 3.6.6.12 and 3.7.9.3).

Item 5.5.10 lists the following ventilation filter systems under VFTP: (1) Containment Post-Accident Charcoal System, (2) Containment Recirculation Fan Cooler System, (3) Control Room Emergency Air Treatment System (CREATS) and (4) Spent Fuel Pool (SFP) Charcoal Adsorber System. The containment post-accident charcoal system and the containment recirculation system contain charcoal adsorbers and HEPA filters, respectively. These are provided to reduce radioiodine releases from the containment to the environment during accidents. The CREATS contains both charcoal adsorbers and HEPA filters, which are provided to ensure control room habitability during accidents by filtering the radioiodine in the control room atmosphere (i.e., about 2000 CFM of the recirculated air in the control room passes through the HEPA filters and charcoal adsorbers during accidents). The SFP charcoal adsorber system contains charcoal adsorbers which are provided to reduce radioiodine releases from the spent fuel pit to the environment during fuel handling accidents. The HEPA filters filter radioiodine in particulate form while the charcoal adsorbers filter radioiodine in elemental and organic forms.

The VFTP states that the following tests, as applicable, will be performed: (1) tests for pressure drop across charcoal adsorber banks; (2) tests for pressure drop across HEPA filter banks; (3) in-place tests for penetration and system bypass of charcoal adsorbers; (4) in-place tests for penetration and system bypass of HEPA filters; (5) laboratory tests on carbon samples from charcoal adsorbers for determining organic iodine removal efficiency of the adsorbers; and (6) tests of flow rates through the existing SFP charcoal adsorbers as a fraction of measured flow rate through a complete set of new SFP charcoal adsorbers.

The VFTP description further states that the test methods will be in accordance with Regulatory Guide (RG) 1.52, "Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmospheric Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants," Revision 2. In addition, the VFTP includes the associated acceptance criteria. With one exception, test frequencies will be in accordance with RG 1.52, Revision 2. The one exception from the regulatory guide is that in lieu of 18-month test intervals, a 24-month test interval will be implemented.

By letter dated October 18, 1995, the licensee stated that historical plant maintenance and surveillance data support extension of periodic filter testing from 18 to 24 months. In addition, by letter dated November 1, 1995, the licensee provided a summary sheet of its test findings on all filter systems. The summary sheet showed that by periodically replacing charcoal adsorbers and HEPA filters following system contamination events (i.e., smoke or painting) or expiration of filter media (i.e., greater than 720 hours of filter operation), all tests since 1980 on filter systems successfully met the test acceptance criteria. The NRC staff has reviewed this information and concurs that

the licensee's maintenance and surveillance practices support an extension of periodic filter testing from 18 to 24 months.

In its October 18, 1995, submittal, the licensee provided minimum flow rates through the HEPA filters in the containment recirculation system, through charcoal adsorbers in the post-accident charcoal system, and through HEPA filters and charcoal adsorbers in the CREATS. The licensee stated that these minimum flow rates would be identified in the Bases of the newly proposed SRs 3.6.6.5, 3.6.6.6, and 3.7.9.2, which deals with filter testing for containment post-accident charcoal system, containment recirculation system and CREATs, respectively. The NRC staff finds the licensee's proposed revision of the Bases to identify minimum flow rates through each applicable system filter train is an improvement over the existing TS which does not provide such flow rates.

In addition, the licensee stated that there is no minimum flow rate through the SFP charcoal adsorbers. Proposed SR 3.7.10.1, which requires daily verification of the auxiliary building ventilation system operation during fuel movement, will ensure that the auxiliary building is being maintained at a negative pressure (with respect to outside environment) by drawing air from the surface of the spent fuel pool through the SFP charcoal adsorbers. This, in turn, will ensure that the SFP charcoal adsorbers perform their intended function.

The NRC staff has reviewed the proposed SRs and conclude that they are either consistent with or represent an improvement over existing TS. Proposed SRs 3.6.6.4, 3.6.6.6 and 3.7.9.1 require monthly operability tests for: (1) each containment recirculation fan cooler unit; (2) each containment post-accident charcoal system train; and (3) the CREATS filter train, respectively. In addition, proposed SRs 3.6.6.14, 3.6.6.15 and 3.7.9.3 call for verification of automatic actuation of: (1) each fan cooler unit in the containment recirculation system (i.e., flow through the system fan cooler unit HEPA filters); (2) each charcoal filter train damper in the containment post- accident charcoal system; and (3) the CREATS (i.e., flow through the CREATS HEPA filters and charcoal adsorbers), respectively, at least once every 24 months.

The NRC staff's review focused on (1) the VFTP description provided in Item 5.5.10 and the SRs for ensuring adequate performance of the ventilation filter systems; (2) extension of test intervals from 18 to 24 months for periodic tests involving the containment post-accident charcoal system, containment recirculation system, CREATS and SFP charcoal adsorber system; and (3) extension of actuation test intervals on the containment recirculation system, containment post-accident charcoal system and CREATS from 18 to 24 months.

The NRC staff finds the test methods and frequencies in the VFTP description, acceptable, since these will be in accordance with RG 1.52, Revision 2. The NRC staff also concludes that the proposed VFTP description provided in Item 5.5.10 is consistent with NUREG-1431, Revision 1. Therefore, based on the NRC staff's review as described

above, the NRC staff finds the VFTP as described in Item 5.5.10 acceptable.

4.3 Evaluation of Surveillance Frequencies and Out of Service Times for The Reactor Protection Instrumentation System and The Engineered Safety Features Actuation System (WCAP-10271)

By letters dated August 31, 1995, September 15, 1995, and November 20, 1995, the licensee proposed to amend the R. E. Ginna Nuclear Power Plant (Ginna), Technical Specifications (TS), Appendix A to Operating License DPR-18. The proposed amendment would incorporate Limiting Condition for Operation requirements from WCAP-10271 with its revisions and supplements, into TS Tables; 3.5-1, "Protection System Instrumentation," 3.5-2, "Engineered Safety Feature Actuation Instrumentation," and 4.1-1, "Minimum Frequencies for Checks, Calibrations and Test of Instrument Channels." This amendment will allow longer surveillance test intervals (STIs) and allowed outage times (AOTs) for the reactor trip system (RTS) and engineered safety features actuation system (ESFAS) instrumentation.

The Westinghouse Owners Group (WOG) proposed TS changes to increase STIs and AOTs to minimize the number of inadvertent trips and challenges to the safety systems while maintaining the benefits of routine tests and maintenance activities to ensure the reliability of the RTS and ESFAS instruments. The WOG published its proposals in WCAP-10271 with its revisions and supplements. The NRC staff has issued three safety evaluation reports (SERs) on the WOG proposal: RTS SER on February 21, 1985 (WCAP-10271 RTS SER), ESFAS SER on February 22, 1989 (WCAP-10271 ESFAS SER), and a supplemental SER (SSER) on April 30, 1990 (WCAP-10271 SSER). The NRC staff issued an additional clarification letter on July 24, 1985 (WCAP-10271 RTS CLARIFICATION LETTER), which provided further information concerning the staff's position.

The NRC staff evaluated the licensee's proposed TS changes to verify consistency with pre-approved changes and to assure that the licensee has met the conditions associated with those changes, as discussed below.

4.3.1 Verification That Proposed Changes Are Consistent With The Pre-Approved Changes

4.3.1.1 Table 3.5-1. "Protection System Instrumentation"

The licensee proposed revisions to Action Statement 2 to increase the time that an inoperable channel may be maintained in an untripped condition from 1 hour to 6 hours and increase the time that an inoperable channel may be bypassed to allow testing of another channel in the same function from 2 hours to 4 hours. This change is applicable to RTS Functions: 2 (Nuclear Flux Power Range), 5 (Overtemperature ΔT), 6 (Overpower ΔT), and 7 (Low Pressurizer Pressure). This proposed change is acceptable to the NRC staff because it is consistent with the pre-approved changes accepted in the WCAP-10271 RTS SER.

The licensee proposed replacing Action Statement 5 with Action Statement 2 for RTS Functions: 8 (High Pressurizer Pressure), 9 (Pressurizer High Water Level), 10 (Low Flow), 11 (Turbine Trip Low Autostop Oil Pressure), and 13 (Low Steam Generator Water Level). The use of Action Statement 2 would increase the time that an inoperable channel may be maintained in an untripped condition from 1 hour to 6 hours and allow an inoperable channel to be bypassed up to 4 hours to allow testing of another channel in the same function. This proposed change is acceptable to the NRC staff because it is consistent with the pre-approved changes accepted in the WCAP-10271 RTS SER.

The licensee proposed replacing Action Statement 6 with Action Statement 2 for RTS Functions: 14 (Undervoltage 4 kV Bus) and 15 (Underfrequency 4 kV Bus). The use of Action Statement 2 would increase the time that an inoperable channel may be maintained in an untripped condition from 1 hour to 6 hours and allow an inoperable channel to be bypassed up to 4 hours to allow testing of another channel in the same function. This proposed change is acceptable to the NRC staff because it is consistent with the pre-approved changes accepted in the WCAP-10271 RTS SER.

The licensee proposed a revision to Action Statement 7 for RTS Functions: 18 (Loss of Voltage - 480 V Safeguards Bus) and 19 (Degraded Voltage - 480 V Safeguards Bus) to increase the time that an inoperable channel may be maintained in an untripped condition from 1 hour to 6 hours and allow an inoperable channel to be bypassed for up to 4 hours to allow the testing of another channel of the same function. The proposed change is consistent with the pre-approved changes accepted in the WCAP-10271 RTS SER, and is, therefore, acceptable to the NRC staff.

The licensee proposed separating RTS Function 20 (Automatic Trip Logic Including Reactor Trip Breakers) into two functions, Functions: 20 (Automatic Trip Logic) and 21 (Reactor Trip Breakers). For Function 20, ACTION 18 would be added to allow 6 hours to restore an inoperable trip logic train before a plant shutdown is initiated in Modes 1 and 2. ACTION 18 also allows 48 hours to restore an inoperable trip logic train prior to initiating action to open the breakers in Modes 3, 4, and 5. For Function 21, ACTION 14 would be revised to increase from 2 hours to 6 hours the time to restore an inoperable breaker before initiating a plant shutdown and allow 48 hours to restore an inoperable breaker prior to initiating action to open the breakers in Modes 3, 4, and 5. This proposed change is consistent with the pre-approved changes accepted in the WCAP-10271 SSER, and is, therefore, acceptable to the NRC staff.

The licensee proposed adding new requirements and action statements for RTS functions which were not previously included in the TS. For Function 11a (Turbine Trip - Stop Valve Closure) Action Statement 21 would be added, for Function 12 (Safety Injection Input from ESFAS) Action Statement 15 would be added, and for Function 22 (RCP·Pump Breaker Position) Action StatementS 16 and 17 would be added.

For Function 11a, Action Statement 21 requires an inoperable channel to be placed in the tripped condition within 6 hours. This is consistent with the pre-approved changes accepted in the WCAP-10271 RTS SER, and is, therefore, acceptable to the NRC staff.

For Function 12, Action Statement 15 allows 6 hours to restore an inoperable channel to operable status before requiring shutdown to hot shutdown within the next 6 hours, and allows bypassing one channel up to 4 hours to allow testing of another channel in the same function. Although this function was not specifically modeled in WCAP-10271, Supplement 1, the proposed mode of applicability and required actions for inoperable channels are consistent with the Westinghouse Standard Technical Specifications, Revision 4 (STS). This change is acceptable to the NRC staff because it is consistent with NUREG-1431.

For Function 22, Action Statement 16 allows an inoperable channel to be restored to operable status within 6 hours or reduce the power level to below 50% thermal power within 2 hours. With the power level below 50% thermal power Action Statement 17 allows continued operation provided the inoperable channel is placed in the tripped condition within 6 hours. Although this function was not specifically modeled in WCAP-10271, Supplement 1, the proposed mode of applicability and required actions for inoperable channels are consistent with NUREG-1431. This change is therefore acceptable to the NRC staff.

The licensee proposed the deletion of Action Statements 5 and 6. Based on the changes described in Sections 3.1.1.(2) and 3.1.1.(3) and the fact that Action StatementS 5 and 6 are no longer imposed on any functions, the deletion of Action StatementS 5 and 6 is an editorial change, and is, therefore, acceptable to the NRC staff.

4.3.1.2 Table 3.5-2. "Engineered Safety Feature Actuation Instrumentation"

The licensee proposed revisions to Action Statement 11 for ESFAS Function 2.c (Containment Spray - High Containment Pressure) to increase the time that an inoperable channel may be maintained in an untripped condition from 2 hours to 6 hours and allow an inoperable channel to be bypassed up to 4 hours to allow testing of another channel in the same function. This proposed change is acceptable to the NRC staff because it is consistent with the pre-approved changes accepted in the WCAP-10271 ESFAS SER.

The licensee proposed replacing Action Statement 9 with Action Statement 11 for ESFAS Function 1.c (Safety Injection - High Containment Pressure). The use of Action Statement 11 would increase the time that an inoperable channel may be maintained in an untripped condition from 1 hour to 6 hours and allow an inoperable channel to be bypassed up to 4 hours to allow testing of another channel in the same function. The licensee also proposed revision of the applicability for Function 1.c from "above 350°F" to above "Cold Shutdown." The Safety Injection function is not used below 350°F except with respect to Containment Isolation. Below

350°F, the only Safety Injection signal that is not blocked is the Containment Pressure High function. Action Statement 9 requires actions leading to RCS temperature less than 350°F and Action Statement 11 requires actions leading to Cold Shutdown. Since this function is only used above 350°F, Action Statement 11 is applicable. This proposed change is acceptable to the NRC staff because it is consistent with the pre-approved changes accepted in the WCAP-10271 ESFAS SER.

The licensee proposed revisions to Action Statement 9, for ESFAS Functions: 1.d (Safety Injection - Steam Generator Low Steam Pressure), 1.e (Safety Injection - Pressurizer Low Pressure), 3.c.i (Auxiliary Feedwater - Steam Generator Water Level Low Start Motor Driven Pump), 5.d (Steam Line Isolation - Containment Pressure), and 6.c (Feedwater Line Isolation - High Steam Generator Level). The revision to Action Statement 9 would increase the time that an inoperable channel may be maintained in an untripped condition from 1 hour to 6 hours and allow an inoperable channel to be bypassed up to 4 hours to allow testing of another channel in the same function. Action Statement 9 also requires that if at any time the number of operable channels is less than the minimum operable channels required, the plant should be in hot shutdown within the next 6 hours and that the plant be at an RCS temperature less than 350°F within the next 6 hours. This proposed change is acceptable to the NRC staff because it is consistent with the pre-approved changes accepted in the WCAP-10271 ESFAS SER.

The licensee proposed replacing Action Statement 12 with Action Statement 9 for ESFAS Functions: 3.c.ii (Auxiliary Feedwater - Steam Generator Water Level Low Start Turbine Driven Pump), 3.d (Auxiliary Feedwater - Loss of 4 kV Voltage), 5.a (Steam Line Isolation - High Steam Flow with Safety Injection), and 5.c (Steam Line Isolation - High Steam Flow and Low T_{avg} with Safety Injection). The use of Action Statement 9 would increase the time that an inoperable channel may be maintained in an untripped condition from 1 hour to 6 hours and allow an inoperable channel to be bypassed up to 4 hours to allow testing of another channel in the same function. This proposed change is acceptable to the NRC staff because it is consistent with the pre-approved changes accepted in the WCAP-10271 ESFAS SER.

The licensee proposed replacing Action Statement 6 with Action Statement 8 for ESFAS Function 3f (Auxiliary Feedwater - Trip of Both MFW Pumps). The use of Action Statement 8 would increase the time that an inoperable channel may be maintained in an untripped condition from 1 hour to 48 hours, and would require the plant to be at an RCS temperature less than 350°F within the next 6 hours. Function 3f was not specifically modeled in WCAP-10271, Supplement 2 since the WOG did not propose any changes for this function. However, the required action is consistent with NUREG-1431, and is, therefore, acceptable to the NRC staff.

The licensee proposed adding new requirements and action statements for ESFAS functions which were not previously in the TS. For Functions: 1.b (Safety Injection - Automatic Actuation Logic and Actuation Relays), 2.b

(Containment Spray - Automatic Actuation Logic and Actuation Relays), and 4.1.b (Containment Isolation - Automatic Actuation Logic and Actuation Relays) Action Statement 20 would be added; for Functions: 3.b (Auxiliary Feedwater - Automatic Actuation Logic and Actuation Relays), 5.b (Steam Line Isolation - Automatic Actuation Logic and Actuation Relays), and 6.b (Feedwater Line Isolation - Automatic Actuation Logic and Actuation Relays) Action Statement 19 would be added; and for Function 4.2.b (Containment Ventilation Isolation - Automatic Actuation Logic and Actuation Relays) Action Statement 13 would be imposed.

For Functions 1.b, 2.b, and 4.1.b, Action Statement 20 allows 12 hours to restore an inoperable channel before requiring shutdown to hot shutdown within the next 30 hours, and allows bypassing one channel up to 8 hours for surveillance testing. Action Statement 20 also allows bypassing of slave relays of one channel up to 12 hours provided the other channel is operable.

For Functions 3.b, 5.b, and 6.b, Action Statement 19 allows 6 hours to restore an inoperable channel before requiring hot shutdown within the next 6 hours. Additionally Action Statement 19 requires the plant to be at an RCS temperature less than 350°F within the next 6 hours. One channel may be bypassed for up to 8 hours for surveillance testing. Action Statement 19 also allows bypassing of slave relays for one channel up to 12 hours provided the other channel is operable.

For Function 4.2.b, Action Statement 13 allows continued operation provided the containment purge and exhaust valves are maintained closed.

These functions, modes of applicability, and required actions for inoperable channels are consistent with the assumptions provided in WCAP-10271, Supplement 2 and are consistent with the pre-approved changes accepted in the WCAP-10271 ESFAS SER, and are, therefore, acceptable to the NRC staff.

The licensee proposed the deletion of Action Statement 12. Based on the changes described in Section 3.1.2.(4) and the fact that Action Statement 12 is no longer imposed on any functions, the deletion of Action Statement 12 is an editorial change, and is, therefore, acceptable to the NRC staff.

4.3.1.3 Table 4.1-1. "Minimum Frequencies For Checks, Calibrations and Test of Instrument Channels"

The licensee proposed revising the channel test frequency from monthly to quarterly for Functions: 4 (Reactor Coolant Temperature), 5 (Reactor Coolant Flow), 6 (Pressurizer Water Level), 7 (Pressurizer Pressure), 8 (4 kV Voltage and Frequency), 11 (Steam Generator Level), 25 (Containment Pressure), 26 (Steam Generator Pressure), 32 (Steam Flow), and 33 (T_{avg}); and from biweekly to quarterly for Function 1 (Nuclear Power Range). This change is consistent with the pre-approved changes accepted in the

WCAP-10271 RTS SER and the WCAP-10271 ESFAS SER, and is, therefore, acceptable to the NRC staff.

The licensee proposed revising the channel test requirement for surveillance to be performed during STARTUP if not performed during the previous 31 days rather than the pervious 7 days for Functions: 1 (Nuclear Power Range), 2 (Nuclear Intermediate Range), and 3 (Nuclear Source Range). Performance of this test during startup if it has not been performed within the last 31 days is consistent with the pre-approved changes accepted in the WCAP-10271 RTS SER CLARIFICATION LETTER, and is, therefore, acceptable to the NRC staff.

The licensee proposed revising the channel test frequency from monthly to STARTUP and deleting the "Block Trip" Note for Function 23 (Turbine Trip Set-Point). Function 23 is used only during STARTUP. The "Block Trip" Note is being deleted because it refers to the performance of a logic combination test that cannot be performed at power since it would cause a reactor trip. Instead this test is performed as part of the refueling outage basis calibration. Therefore, the only real change is the replacement of the monthly verification test with a STARTUP verification test. Performance of this test during STARTUP if it has not been performed within the last 31 days is consistent with the pre-approved changes accepted in the WCAP-10271 RTS SER CLARIFICATION LETTER, and is, therefore, acceptable to the NRC staff.

The licensee proposed changing the channel check frequency from each shift to not applicable and the channel test frequency from monthly to each refueling outage for Function 27 (Turbine First Stage Pressure). Function 27 is a permissive input to P-7. NUREG-1431 does not have a channel check requirement for permissives. The WCAP-10271, Supplement 1 analysis assumed that each channel for the "Turbine Trip" function would be tested once each cycle. The deletion of the channel check and the changing of the channel test frequency from monthly to each refueling outage is consistent with the assumptions made in the WCAP-10271, and is, therefore, acceptable to the NRC staff.

The licensee proposed revising the channel check frequency from daily to STARTUP and the channel test frequency from monthly to quarterly for Function 17 (Reactor Containment Pressure). This change is consistent with the pre-approved changes accepted in the WCAP-10271 ESFAS SER, and is, therefore, acceptable to the NRC staff.

The licensee proposed adding surveillance requirements for a channel test each refueling outage, for Functions 42 (Safety Injection Input from ESFAS) and 43 (RCB Breaker Position Trip) which were not previously in the TS. Functions 42 and 43 were not specifically modeled in WCAP-10271 since the WOG did not propose any changes for these functions. However, the proposed surveillance requirements are consistent with NUREG-1431. Therefore, the proposed surveillance requirements are acceptable to the NRC staff.

The licensee proposed adding surveillance requirements for Functions 44 (Overtemperature ΔT) and 45 (Overpower ΔT) which were not previously in the TS. The proposed surveillance requirements, for channel check each shift, channel calibration each refueling outage, and channel test each quarter, for Functions 44 and 45 are consistent with the assumptions made in WCAP-10271, and are, therefore, acceptable to the NRC staff.

The licensee has proposed adding surveillance requirements for Functions 46 (Safety Injection Manual Initiation (ESFAS)), 47 (Containment Spray Manual Initiation (ESFAS)), 49 (Containment Ventilation Isolation Manual Initiation), 50 (Steam Line Isolation Manual Initiation), 51 (Auxiliary Feedwater Manual Initiation), and 52 (Feedwater Line Isolation Manual Initiation) which were not previously in the TS. These functional units are for manual initiation of engineered safety features functions. The channel tests for these functional units will be performed each refueling outage. Other circuitry associated with manual safeguards actuation will be tested on a staggered bi-monthly basis. The surveillance requirements for these functions are consistent with NUREG-1431, and are, therefore, acceptable to the NRC staff.

The licensee has proposed the relocation of Function 9 (Containment Isolation Trip) from Table 4.1-2 into Table 4.1-1 as Function 48 (Containment Isolation Manual Initiation). Since there is no technical change in the surveillance requirements this becomes an editorial change, and is acceptable to the NRC staff.

4.3.2 Verification of Conditions

In the TS change submittals, the licensee confirmed that the conditions identified by the NRC staff to be satisfied in the generic SERs for WCAP-10271 have been met as described below.

Testing on a staggered basis was originally stipulated in the RTS SER for RTS channels changed to the quarterly test frequency. However, this requirement was later removed in the ESFAS SER. The licensee stated that since this condition was withdrawn it is no longer applicable. This is acceptable to the NRC staff.

The RTS SER required implementation or confirmation of plant procedures that identify/evaluate common cause RTS channel failures and specify additional testing for plausible common cause failures. The licensee stated that plant procedures requiring RTS/ESFAS failures to be evaluated for common cause will be developed prior to implementation of these TS changes. These procedures will follow the general guidance provided in the WOG letter "Revision to WOG Guidelines for Preparation of Submittals Requesting Revisions to RPS Technical Specifications," dated September 3, 1995. This is consistent with the RTS SER condition, and is acceptable to NRC staff.

The RTS SER stipulated that approval of routine channel testing in a bypassed condition is contingent on the capability of the RTS design to allow such testing without lifting leads or installing temporary jumpers. The licensee

stated that the existing design configuration at Ginna does not include a built-in bypass capability. As such, the licensee will not bypass channels that have been placed in the tripped condition. The licensee will only bypass inoperable channels in order to test remaining operable channels. Therefore, the lifting of leads or the addition of jumpers is not necessary to bypass these inoperable channels. This is consistent with the RTS SER condition, and is acceptable to the NRC staff.

The RTS SER states that approval to extend the STI and AOT for channels that provide dual inputs to other safety related systems such as ESFAS, applies to the RTS function only. The licensee stated that since the NRC's review of associated functions has been completed, this condition no longer applies. This is acceptable to the NRC staff.

Staff approval of increased STIs was contingent on confirmation by the licensee that their setpoint methodology includes sufficient margin to offset the additional drift anticipated as a result of less frequent surveillance. The licensee stated that they have evaluated 12 months (January 1994 - January 1995) of RTS/ESFAS monthly surveillance test data for Ginna instrument loops to establish drift values. The evaluation concluded that the worst case setpoint variance was observed to be within allowable limits. The NRC staff has reviewed the licensee's data evaluation and finds it consistent with the generic WCAP-10271 SER condition, and is, therefore, acceptable.

The ESFAS SER states that the licensee must confirm the applicability of the generic analyses to their plant. The licensee stated that the design assumptions and the modeling assumptions presented in Sections 2 and 3 of WCAP-10271, Supplement 2, Revision 1, were reviewed with respect to the Ginna ESFAS design and operational practices. The WCAP information is equivalent to or more bounding with respect to Ginna as follows:

(a) WCAP-10271, Supplement 1, Revision 1 assumes that master and slave relays for actuation logic are tested monthly. However, the Ginna design does not allow for this type of testing at power. Therefore, each ESFAS function is tested on a refueling basis. WCAP-10271, Supplement 1, Revision 1 acknowledges this testing limitation.

(b) WCAP-10271, Supplement 1, Revision 1 assumes that Containment Spray actuation uses 2 out of 4 logic. The Ginna Containment Spray logic is organized in two sets of 2 out of 3 logic. This logic is similar to that modeled in WCAP-10271, Supplement 1 for the Low Flow - Two Loop RTS function. The AOTs and STIs for this similar designed function are, therefore, applicable to Containment Spray.

(c) The WCAP does not specifically evaluate the Loss of Voltage - 480 V Safeguards Bus and Degraded Voltage - 480 V Safeguards Bus functions but proposes changes that are consistent with other ESFAS changes. WCAP-10271, Supplement 1 design analysis assumes a 2 out of 4 logic. The design at Ginna has two sets of logic in which both sets must actuate to generate an undervoltage signal. This design is similar to the RCP Undervoltage and Underfrequency RTS functions as modeled in WCAP-10271, Supplement 1. The AOTs and STIs for this similar designed function are, therefore, applicable to 480 V loss of voltage and degraded voltage.

These responses are consistent with the generic WCAP-10271 SER conditions, and are, therefore, acceptable to the NRC staff.

Based on the above, the NRC staff concludes that the proposed TS changes to the Ginna RTS and ESFAS surveillance test intervals and allowable outage times are consistent with 1) the NRC staff's previous generic approval and required plant specific conditions as described in the SERs for WCAP-10271 and its revisions and supplements, and 2) the Westinghouse STS, and are, therefore, acceptable.

4.4 Pressurizer Safety Valve Setpoints Tolerance

By letter dated May 26, 1995, supplemented by letter dated November 27, 1995, Rochester Gas & Electric Corporation made application to amend the TS by modifying TS related to pressurizer safety valve (PSV) setpoint tolerance from +/- 1% to +2.4%, -3%.

The PSVs provide protection from overpressurization of the Reactor Coolant System (RCS). By increasing the positive side of the tolerance, the allowable lifting pressure is increased from that which was assumed in the UFSAR. Thus, the resulting peak RCS pressure would be greater than the existing analyzed value for a limiting pressure transient. By increasing the negative side of the tolerance, the allowable lifting pressure is decreased, which leads to the potential reduction of margin to departure from nuclear boiling ratio (DNBR) during some transients. However, the lifting of the pressurizer power operated relief valves (PORVs) is assumed in this analysis. Since the PORV setpoints are significantly lower than the PSV lifting pressure, the slightly reduced PSV setpoint would not affect the results of the existing analysis for transients with concerns to DNBR.

To support the proposed TS for PSV setpoint tolerances, the licensee has performed an evaluation and analyses to determine the impact on the design basis accidents and transients for Ginna. All of the transients and accidents documented in the UFSAR were evaluated by the licensee to determine the impact of the proposed changes to the TS. For the cases where the TS changes had an adverse impact on the event consequences, a detailed evaluation or reanalysis of the event has been performed.

The licensee has identified the loss of external electrical load as the limiting transient regarding peak primary and secondary system pressures. The licensee has reanalyzed cases for this transient with and without automatic pressure control. The results of its analysis indicate that the most limiting peak primary pressure is 2739 psia and the most limiting peak secondary system pressure is 1180 psia. Since the peak transient primary and secondary system pressures are within 110% of their system design pressures, the results are acceptable to the NRC staff. The licensee's evaluation concluded that the impacts of the proposed TS changes to all other heatup transients and accidents are bounded by the consequences of the loss of external electrical load transient.

The licensee has evaluated the effects of the TS changes to a small-break LOCA and determined that the peak RCS pressure stays below the PSV setpoint following a small break LOCA at Ginna. Therefore, the proposed TS change would not affect the existing safety analysis. Since the licensee is not changing the main steam safety valve (MSSV) setpoint tolerances, the radiological consequences of a steam generator tube rupture event are not affected.

The NRC staff has reviewed the results of the licensee's assessment and agrees with its conclusion. The revision of the PSV setpoint tolerances are therefore acceptable.

4.5 Reactor Coolant Reactivity Levels

Following the Ginna steam generator tube rupture (SGTR) event on January 25, 1982, the SGTR subgroup of the Westinghouse Owners Group (WOG) submitted WCAP-10698, "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill," dated December 1984, for NRC staff review. WCAP-10698 also references WCAP-10698, Supplement 1, "Evaluation of Offsite Radiation Doses for a Steam Generator Tube Rupture Accident."

By letter dated March 30, 1987, the NRC staff responded to the SGTR subgroup, "Acceptance for Referencing of License Topical Report WCAP-10698, 'SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill,'"). In this letter, the NRC staff concluded that the WOG provided an acceptable and conservative methodology for the generic SGTR analysis. However, the NRC staff also concluded that five confirmatory issues used in the analysis may vary significantly from plant to plant, thus altering the steam generator overfill and radiological dose results. Therefore, the NRC staff concluded that each member of the SGTR subgroup and all the Westinghouse NTOLs (near-term operating licenses) would be required to submit plant specific information concerning these five confirmatory issues before the methodology from WCAP-10698 could be implemented.

By letter dated May 23, 1994, Rochester Gas and Electric Corporation submitted a license amendment request to increase the primary coolant activity by revising existing TSs 3.1.4.1.a, 3.1.4.1.b, and Figure 3.1.4-1. The amendment request included an analysis of the potential radiological consequences due to a steam generator tube rupture (SGTR) for the R. E. Ginna Nuclear Power Plant. The five confirmatory issues, along with the NRC staff's response, are listed below:

4.5.1 Demonstrate that the operator action times assumed in the analysis are realistic

The NRC staff's evaluation determined the adequacy of operator action times by the following additional criteria:

<u>Criterion 1</u> Provide simulator and emergency operating procedure (EOP) training related to a potential SGTR.

By letter dated May 23, 1994, the licensee documented that onsite simulator and EOP training relevant to an SGTR were provided. The NRC staff finds that the licensee has satisfied Criterion 1.

<u>Criterion 2</u> Utilizing typical control room staff as participants in demonstration runs, show that the operator response times assumed in the SGTR analysis are realistic and achievable.

By letter dated May 23, 1994, the licensee submitted the assumed and demonstrated operator response times for the two most limiting SGTR scenarios. The assumed and demonstrated operator response times are shown in Tables 1 and 2.

Table 1 <u>Intact Steam Generator Power-Operated Relief Valve (PORV) Fails Closed</u>

OPERATOR ACTION	ASSUMED TIME (in seconds)	DEMONSTRATED TIME (in seconds)
Isolate ruptured SG	600	423
Locally open intact SG PORV	1804	1460
Terminate safety injection	2798	1916
Terminate break flow	3428	2541

Table 2 <u>Ruptured SG PORV Fails Open</u>

OPERATOR ACTION	ASSUMED TIME (in seconds)	DEMONSTRATED TIME (in seconds)
Isolate ruptured SG	652	214
Locally isolate failed PORV	1558	1116
Terminate safety injection	3066	2073
Terminate break flow	3438	2424

During a conference call on May 17, 1995, the licensee indicated that the demonstrated times in Tables 1 and 2 were the results of demonstration runs representing about 50% of the Ginna operating crew personnel.

On the basis of the above information and that the licensee's operator response times are less than the times assumed in the plant-specific analysis, the NRC staff finds that the licensee has satisfied Criterion 2.

<u>Criterion 3</u> Complete demonstration runs to show that the postulated SGTR accident can be mitigated within a period compatible with overfill prevention, using design-basis assumptions regarding available equipment and its impact on operator response times.

As noted above, the demonstrated times for the two most limiting SGTR scenarios are bounded by the assumed operator response times. By letter dated June 15, 1995, the licensee committed to complete demonstration runs representing a minimum of 80% of the Ginna operators. On the basis of results of demonstration runs representing about 50% of the Ginna operating crews and the licensee's commitment above, the NRC staff finds that the licensee has provisionally satisfied Criterion 3. However, the licensee is expected to successfully complete the additional demonstration runs representing 80% of the Ginna operating crew personnel and submit the results to the NRC. This is a confirmatory issue.

<u>Criterion 4</u> If the EOPs specify SG sampling as a means of identifying the SG with the ruptured tube, provide the expected time period for obtaining the sample results and discuss the effect on the duration of the accident.

In the letter dated July 11, 1995, the licensee stated that EOPs allow SG sampling as a means of identifying the ruptured SG and that the sampling was estimated to take about 2 hours. The licensee also stated the following:

- This method is a backup to (1) unexpected increase in either steam generator narrow range level, (2) high radiation indication of steam line radiation monitors, or (3) local indication of high steamline radiation.

- The sampling of SG to identify which SG has the ruptured tube is not credited in the UFSAR, Chapter 15 analysis, or the plant-specific analysis on the consequences of an SGTR. Instead, the air ejector radiation monitors and radiation monitors in the steam line or blowdown lines provide the first indication of a ruptured SG.

- Ginna is a two-loop plant which makes identification of a ruptured SG less difficult than for plants with more reactor coolant loops.

On the basis of this information, the NRC staff finds that Criterion 4 is satisfied.

The NRC staff has reviewed the licensee's responses regarding operator response times during an SGTR and concludes that the licensee's demonstrated times for Ginna operators and its commitment to conduct additional demonstration runs are satisfactory.

4.5.2 Perform a site specific SGTR radiation offsite consequence analysis

Regarding existing TS 3.1.4.1.b (Improved TS LCO 3.4.16) and Figure 3.1.4-1 [Improved TS Figure 3.4.16-1], the NRC staff performed a radiological dose assessment to determine the consequences of increasing the primary coolant dose equivalent iodine-131 activity limit from 0.2 microcuries per gram to 1.0 microcuries per gram. The NRC staff calculated the potential consequences for the two cases contained in the November 1987 Westinghouse report entitled "LOFTR2 Analysis of Potential Radiological Consequences Following a Steam Generator Tube Rupture at the R. E. Ginna Nuclear Power Plant" (WCAP-1166).

Each case was analyzed for an accident initiated iodine spike and a preaccident iodine spike. For the accident initiated spike condition, the NRC staff's calculations indicate that the thyroid doses are within the acceptance criteria presented in SRP 15.6.3 of NUREG-0800 and less than the 30 rem thyroid value stated in SRP 6.4, which is defined as equivalent to a 5 rem whole body value presented in General Design Criterion 19. For the preaccident spike condition, the NRC staff's calculations indicate that thyroid doses could potentially exceed the 30 rem thyroid value if the primary coolant activity concentration were to reach 60 microcuries per gram of dose equivalent iodine-131. However, doses based on a maximum permissible activity of 25 microcuries per gram of dose equivalent iodine-131 would be less than the 30 rem thyroid value and meet the acceptance criteria presented in SRP 15.6.3 of NUREG-0800. Therefore, the NRC staff recommended that Figure 3.1.4-1 [Improved TS Figure 3.4.16-1] be revised to illustrate a maximum allowable operation region of 25 microcuries per gram of dose equivalent iodine-131 rather than the proposed operation region of 60 microcuries per gram of dose equivalent iodine-131. Following discussions with the licensee, the licensee agreed to revise Figure 3.1.4-1 per the NRC staff's recommendations, as reflected in the licensee's written submittal of December 28, 1995.

Based on the above, the NRC staff concludes that the radiological dose consequences of a steam generator tube rupture with a technical specification value for primary coolant dose equivalent iodine-131 activity of 1.0 microcuries per gram and a maximum allowable operation region of 25 microcuries per gram of dose equivalent iodine-131 are within the acceptance criteria presented in SRP 15.6.3 of NUREG-0800 and General Design Criterion 19.

Regarding existing TS 3.1.4.1.a, the NRC staff has reviewed the licensee's request to increase the total primary coolant activity from 84/E microcuries per gram to 100/E microcuries per gram. The staff concluded that the radiological dose consequences of a total primary coolant activity of 100/E microcuries per gram is within the acceptance criteria of 10 CFR Part 100 and General Design Criterion 19.

4.5.3. Evaluate the adequacy of the main steam lines and associated supports under water-filled conditions as a result of SGTR overfill;

4.5.4. Provide a list of systems, components and instrumentation which are credited for accident mitigation in the plant specific SGTR EOPs; and

4.5.5. Survey the designs of the primary and balance of plant systems design to determine the compatibility with the bounding analysis in WCAP-10698.

The licensee provided satisfactory responses to confirmatory issues 3, 4 and 5 listed above. The licensee performed the plant specific margin to steam generator overfill SGTR analysis using the LOFTTR2 computer code for Ginna. The SGTR analysis assumptions and operator action times were consistent with the reference plant analysis. The results of this analysis indicate that the recovery actions can be completed to terminate the primary to secondary break flow before overfill of the ruptured steam generator would occur. Therefore, it is concluded that steam generator overfill is not likely for a design basis SGTR event for Ginna.

4.6 Evaluation of 10 CFR Part 50, Appendix J Requirements

Compliance with Appendix J provides assurance that the primary containment, including those systems and components which penetrate the primary containment, do not exceed the allowable leakage rate values specified in the technical specifications and Bases. The allowable leakage rate is determined so that the leakage assumed in the safety analyses is not exceeded.

On February 4, 1992, the NRC published a notice in the Federal Register (57 FR 4166) discussing a planned initiative to begin eliminating requirements marginal to safety which impose a significant regulatory burden. 10 CFR Part 50, Appendix J, "Primary Containment Leakage Testing for Water-Cooled Power Reactors" was considered for this initiative and the NRC staff undertook a study of possible changes to this regulation. The study examined the previous performance history of domestic containments and examined the effect on risk of a revision to the requirements of Appendix J. The results of this study are reported in NUREG-1493, "Performance-Based Leak-Test Program".

Based on the results of this study, the NRC staff developed a performance-based approach to containment leakage rate testing. On September 12, 1995, the NRC approved issuance of this revision to 10 CFR Part 50, Appendix J, which was subsequently published in the Federal Register on September 26, 1995, and became effective on October 26, 1995. The revision added Option B "Performance-Based Requirements" to Appendix J to allow licensees to voluntarily replace the prescriptive testing requirements of Appendix J with testing requirements based on both overall and individual component leakage rate performance.

Regulatory Guide 1.163, "Performance-Based Containment Leak Test Program", was developed as a method acceptable to the NRC staff for implementing Option B. This regulatory guide states that NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J" provides methods acceptable to the NRC staff for complying with Option B with four exceptions which are described therein, as discussed below.

Option B requires that Regulatory Guide 1.163 or another implementation document used by a licensee to develop a performance-based leakage testing program must be included, by general reference, in the plant technical specifications. The licensee has referenced Regulatory Guide 1.163 in the Ginna Technical Specifications.

Regulatory Guide 1.163 specifies an extension in Type A test frequency to at least one test in 10 years based upon two consecutive successful tests. Type B tests may be extended up to a maximum interval of 10 years based upon completion of two consecutive successful tests and Type C tests may be extended up to 5 years based on two consecutive successful tests.

By letter dated October 20, 1995, NEI proposed technical specifications for implementing Option B. After some discussion, the NRC staff and NEI agreed on a set of model technical specifications which were transmitted to NEI in a letter dated November 2, 1995. These technical specifications are to serve as a model for licensees to develop plant specific technical specifications in preparing amendment requests to implement Option B.

In order for a licensee to determine the performance of each component, factors that are indicative of or affect performance, such as an administrative leakage limit, must be established. The administrative limit is selected to be indicative of the potential onset of component degradation. Although these limits are subject to NRC inspection to assure that they are selected in a reasonable manner, they are not technical specification requirements. Failure to meet an administrative limit requires the licensee to return to the minimum value of the test interval.

Option B requires that the licensee maintain records to show that the criteria for Type A, B and C tests have been met. In addition, the licensee must maintain comparisons of the performance of the overall containment system and the individual components to show that the test intervals are adequate. These records are subject to NRC inspection.

By letter dated November 27, 1995, the licensee submitted proposed changes to the technical specifications based on the new Option B. The proposed changes would revise the technical specifications to reflect the approval for the licensee to use 10 CFR Part 50, Appendix J, Option B for the Ginna containment leakage rate test program. Option B permits a licensee to choose Type A; or Type B and C; or Type A, B and C; testing to be done on a performance basis. The licensee has elected to perform Type A, B, and C testing on a performance basis.

Option B contains several provisions which relate to implementation. They are discussed below:

1. *Specific exemptions to Option A of this appendix that have been formally approved by the AEC or NRC, according to 10 CFR Part 50.12, are still applicable to Option B of this appendix if necessary, unless specifically revoked by the NRC.*

The current Ginna license has four exemptions with respect to 10 CFR Part 50, Appendix J, Option A, which are proposed to be removed as part of this license amendment request.

2. *A licensee or applicant for an operating license may adopt Option B, or parts thereof, as specified in Section V.A of this Appendix, by submitting its implementation plan and request for revision to technical specifications to the Director of the Office of Nuclear Reactor Regulation.*

   The licensee's letter of November 27, 1995, serves as the request to change the Ginna TS to implement Option B. The licensee plans to implement Option B as part the implementation of the improved standard technical specifications. This implementation is anticipated to occur in or about February 1996.

3. *The regulatory guide or other implementation document used by a licensee, or applicant for an operating license, to develop a performance-based leakage-testing program must be included, by general reference, in the plant specifications. The submittal for technical specification revisions must contain justification, including supporting analyses, if the licensee chooses to deviate from methods approved by the Commission and endorsed in a regulatory guide.*

   The licensee's letter of November 27, 1995, proposes to add a specific reference to Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," in the Administrative Controls section (i.e., Section 5.5.15) of the Ginna TSs. No exceptions to the regulatory guide, nor the documents which are endorsed by the regulatory guide, are being requested. Therefore, the licensee does not propose to "deviate from methods approved by the Commission and endorsed in a regulatory guide."

4. *The detailed licensee programs for conducting testing under Option B must be available at the plant site for NRC inspection.*

   The detailed performance-based leakage-test program will be available for NRC inspection upon implementation of the improved technical specifications for Ginna as discussed above.

The following discussion of proposed changes to the Ginna TSs are categorized depending on whether the change is either more or less restrictive than the existing technical specifications, administrative in nature, or the requirement is removed or deleted.

4.6.1 More Restrictive Changes

Option B, as implemented by Regulatory Guide 1.163, no longer allows the use of reduced pressure Type A tests (integrated leak rate tests). Therefore, Type A tests which could be performed at equal to or greater than 35 psig must now be performed at equal to or greater than 57.6 psig and less than 60 psig per ANSI/ANS 56.8-1994.

Accordingly, definitions and acceptance criteria for performing reduced pressure Type A tests were deleted from existing TSs 4.4.1.1, 4.4.1.3.c, 4.4.1.4.a, and 4.4.1.4.b.

The existing TS 4.4.2.3 does not address leakage past the containment air locks. Existing TS 4.4.2.3 was revised to provide acceptance criteria for containment air locks as required by NEI 94-01. With the exception of minor word changes, these acceptance criteria are consistent with the November 2, 1995 letter from NRC to NEI, "Implementation of 10 CFR 50, Appendix J."

The existing TS 4.4.2.3.b was revised to require that penetrations which result in a failure to meet Type B and C leakage limits must be restored within 1 hour versus 48 hours before requiring a plant shutdown. The 1-hour time frame provides consistency with existing TS 3.6.1 with respect to containment OPERABILITY and NUREG-1431. This requirement was then relocated to LCO 3.6.1. Also, existing TS 4.4.2.3.c was revised to allow 24 hours to restore a Mini-Purge penetration with a high leakage rate versus performing an engineering evaluation and developing plans for corrective actions. This requirement now provides clear instructions to plant operators with a defined time period for restoring OPERABILITY. The actual leakage limit is to be relocated to the Administrative Controls section of technical specifications with the restoration requirement relocated to LCO 3.6.3.

4.6.2 Less Restrictive Changes

The current TS 4.4.1.3.b provides the requirements for verification of the accuracy of test instrumentation and calculational methods during the Type A test with respect to L_t (maximum allowable leakage during reduced pressure tests). This was deleted since performing Type A at reduced pressure is no longer allowed by Option B as implemented by Regulatory Guide (RG) 1.163. Instead, ANSI/ANS 56.8-1994 provides the necessary verification requirements. This is identified as being less restrictive since additional options are now provided with the existing TS requirement being deleted. These new options have all been accepted for use by the NRC via RG 1.163. Therefore, this is considered an acceptable change.

The current TS 4.4.1.4.c was revised to state that the Type A leakage limit prior to entering Mode 4 following a Type A test is equal to or less than 0.75 L_a, but this increases to less than 1.0 L_a following the Mode transition until the next Type A test is performed. This change is consistent with the November 2, 1995, letter from NRC to NEI, "Implementation of 10 CFR 50, Appendix J," and provides margin for additional leakage that may occur between tests. The value of 1.0 L_a is used in the dose analyses such that this new leakage limit of less than 1.0 L_a remains within the accident analyses assumptions, and therefore, the 10 CFR Part 100 limits are maintained. Therefore, this change is considered acceptable.

The existing TS 4.4.1.5.a.i was removed and revised to change the testing frequency requirements for Type A tests. The removal of the Type A test frequency is addressed in the Removal/Deleted section below. However, as part of removing these testing frequencies, NEI 94-01 allows the frequency to change from 3 times every 10 years (with no more than 4 years in-between tests) to once every 10 years provided that 2 successful tests have been performed. Also, this once every 10 years can be extended to 11 years, 3 months if required. This test frequency is acceptable because it complies with the provisions of RG 1.163.

The existing TSs 4.4.1.5.a.ii, 4.4.2.4.a, and 4.4.2.4.b were removed and revised to change the Type B and C testing frequencies. The removal of these testing frequencies is addressed in the Removal/Deleted section below. However, as part of removing these testing frequencies, RG 1.163 and NEI 94-01 allow testing of Type B penetrations to be increased to once every 120 months (with an additional 15 months allowed) provided that 2 successful tests have been performed. Type C tests can be increased to once every 60 months (with an additional 15 months allowed) provided that two successful tests have been performed. The revised testing frequency is consistent with RG 1.163 and NEI 94-01. Therefore, this change is considered acceptable.

The existing TSs 4.4.1.5.b and 4.4.1.5.c were removed and revised as follows (the removal is addressed in the Removal/Deleted section below):

a. The requirement to submit a new test schedule to the NRC for review and approval following the failure of one Type A test was deleted and replaced with a requirement to perform a retest within 48 months per NEI 94-01. Tests must then continue at a frequency of once every 48 months (but no less than 24 months apart) until two consecutive successful tests are conducted. At that time, the test frequency can extend to once every 10 years. Requiring the first test within 48 months and the succeeding tests at a maximum 48-month intervals is consistent with existing TS 4.4.1.5.a.i. Therefore, the only change being requested is to delete the requirement to submit a new testing schedule for NRC review and approval. Since the new testing interval has been generically approved by the NRC via RG 1.163, this change is considered acceptable.

b. The requirement to perform a retest within 18 months or the next refueling outage, whichever comes first, following the failure of two consecutive tests was also deleted per NEI 94-01. Instead, leakage tests must continue on an interval of every 24 to 48 months until two tests are successfully performed. At that time, the testing frequency can extend up to 10 years. Therefore, the only change being requested is to eliminate the requirement to perform a retest within 18 months. This change is considered acceptable since the NRC has generically approved the new testing frequency via RG 1.163.

The existing TS 4.4.1.6 was removed and revised to change the reporting requirements for Type A tests. The removal of the Type A test reporting requirements is addressed in the Removal/Deleted section below. However, as part of removing the report, NEI 94-01 no longer provides for submittal of the report to the NRC staff. Instead, this report must be available on-site for NRC inspection. This approach has been generically approved by the NRC via RG 1.163. Therefore, this change is considered acceptable.

The existing TS 4.4.2.1.a was removed and revised to change the pressure at which Type A test is to be performed. The removal of these testing requirements is addressed in the Removal/Deleted section below. However, as part of removing this requirement, ANSI/ANS 56.8-1994 allows valves to be tested at equal to or greater than 0.96 P_a but no greater than the containment design pressure. Since the value of P_a is equivalent to the design pressure of 60 psig, the Type A test must be conducted between 57.6 and 60 psig. This small difference in pressure is considered acceptable due to the conservatisms employed in calculating P_a. Also, the actual post-LOCA peak containment pressure is estimated to be equal to or less than 55 psig which remains bounded by the new leak test pressure definition of P_a. Therefore, this change is considered acceptable.

The existing TS 4.4.2.1.a was removed and revised to change the pressure at which Type B and C tests are to be performed. The removal of these testing requirements is addressed in the Removal/Deleted section below. However, as part of removing this requirement, ANSI/ANS 56.8-1994 allows valves to be tested at equal to or greater than P_a. Because this complies with the provisions of RG 1.163, this change is considered acceptable.

The existing TS 4.4.2.4.c was removed and revised to change the testing frequency of containment air locks. The removal of these testing frequencies is addressed in the Removal/Deleted section below. However, as part of removing these requirements, NEI 94-01 allows the air lock testing frequencies to change as follows:

a. The air locks must be tested once every 30 months (versus 6 months) by pressurizing the space between the air lock doors. This change is consistent with NEI 94-01. Therefore, this change is considered acceptable.

b. The air lock doors must be tested within 7 days of being opened in Modes 1, 2, 3, and 4 versus 48 hours. This time limit can extend up to 30 days if the door is being opened more frequently than once every 7 days. However, the doors must be tested prior to entering Mode 4 from Mode 5 whether the doors are used or not. These changes are consistent with NEI 94-01. Therefore, this change is considered acceptable.

4.6.3 Administrative Changes

All retained Appendix J related testing requirements are being relocated to the Administrative Controls section of the technical specifications. This

provides equivalent control since any changes to the Administrative Controls section requires NRC review and approval. The location of this information in the Administrative Controls section is also consistent with NRC recommendations for implementation of Option B.

The definitions of P_a and L_a found in existing TS 4.4.1.1 were revised to make the wording consistent with that provided in Option B and the November 2, 1995 letter from NRC to NEI, "Implementation of 10 CFR 50, Appendix J." Since the actual values of these parameters remain the same, there is no difference with respect to performing the leakage tests (i.e., the leakage test pressure of P_a) or with respect to determining acceptable leakage and its impact on offsite dose calculations (i.e., L_a).

The current TS 4.4.1.3.a was revised to replace reference to American National Standard N45.4-1972 with ANSI/ANS 56.8-1994 (as endorsed by RG 1.163) for performance of Type A tests. Both standards are approved for use in the performance of ILRTs by the NRC. The use of ANSI/ANS 56.8-1994 is also required in order to implement Option B without NRC review of an alternate methodology.

The Ginna license was revised to remove four exemptions to 10 CFR Part 50, Appendix J, Option A. These exemptions are discussed in detail below:

a. The exemption from Section III.A.4(a) with respect to the maximum allowable leakage rate for reduced pressure tests is no longer required since Option B, as implemented by RG 1.163, does not allow the use of reduced pressure tests.

b. The exemption from Section III.B.1 with respect to the acceptable technique for performing local Type B leakage rate tests is no longer required since ANSI/ANS 56.8-1994 provides the necessary allowances for the type of testing equipment to be used.

c. The exemption from Section III.D.1 for scheduling of containment integrated leakage rate tests with respect to 10 year ISI intervals is no longer required, because Option B no longer requires this coordination between the Type A tests and the 10 year ISI.

d. The exemption from Section III.D.2 with respect to the testing interval of containment airlocks is no longer required since NEI 94-01 provides testing intervals which are longer than those contained in the Ginna TS.

4.6.4 Removed/Deleted

Numerous existing TS requirements related to Appendix J testing were removed from existing TS since they are contained in either RG 1.163, NEI-94-01, or ANSI/ANS 56.8-1994. Since a reference to RG 1.163 is being provided in the Administrative Controls section of technical specifications, and this regulatory guide specifically endorses NEI 94-01 and its use of ANSI/ANS 56.8-

1994, there is no need to duplicate the same requirements within technical specifications.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New York State official was notified of the proposed issuance of the amendment. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32 and 51.35, an environmental assessment and finding of no significant impact with respect to the NUREG-1431 TS changes has been prepared and published in the Federal Register on January 23, 1996 (61 FR 1785). Accordingly, based upon the environmental assessment, the NRC staff has determined that the issuance of this portion of the amendment will not have a significant effect on the quality of the human environment.

With respect to the non-NUREG-1431 TS changes listed in Section 4.0 above, the amendment changes requirements with respect to installation or use of facility components located within the restricted area as defined in 10 CFR Part 20 and changes surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that this portion of the amendment involve no significant hazards consideration, and there has been no public comment on such findings 59 FR 34669, 60 FR 45184, and 60 FR 63071). Accordingly, this portion of the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9).

7.0 CONCLUSION

The Ginna Nuclear Power Station improved TS provide clearer, more readily understandable requirements to ensure safe operation of the plant. The NRC staff has concluded that the improved TS satisfy the guidance in the NRC Final Policy Statement with regard to the content of technical specifications, and conform to the model provided in NUREG-1431 with appropriate modifications for plant-specific considerations. The NRC staff has concluded that the Ginna Nuclear Power Station improved TSs satisfy Section 182a of the Atomic Energy Act, 10 CFR 50.36, and other applicable standards. On this basis, the NRC staff concludes that the proposed Ginna Nuclear Power Station improved TSs are acceptable.

The Commission has concluded that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

Principal Contributors: C. Schulten
C. E. Carpenter
A. Johnson
E. Sullivan
F. Gee
D. Pickett
M. Chatterton
R. Jenkins
T. Chandrasekaran
B. Marcus
C. Liang
G. West
R. Emch
K. Desai

Date: February 13, 1996

Summary of Ginna Nuclear Power Station Totally and Partially Relocated Technical Specifications

TABLE 1
RELOCATED TO CORE OPERATING LIMITS REPORT (COLR)
(Changes controlled by Specification 5.6.5 and 10 CFR 50.59)

ITEM #(1)	CTS #	DESCRIPTION
20.iii	3.10.1.1, Figure 3.10-2	Shutdown Margin Limits
20.v	3.10.1.3, Figure 3-10.1	Control Bank Limits
20.xxiii	3.10.2.2	$F_Q(Z)$ and $F^N_{\Delta H}$ Limits
20.xxxv	3.10.2.10a	AFD Target Band
20.xxxiii	3.10.2.8	AFD Target Band

(1) From Attachment A, Section D of licensee's application dated May 26, 1995

TABLE 2
RELOCATED TO UFSAR
(Changes controlled by: (1) 10 CFR 50.54 or (2) 10 CFR 50.59)

ITEM #(1)	CTS #	DESCRIPTION	CHANGE CONTROL
15.i.a	Table 3.5-1	Various Instrumentation Operational Details	(1)
15.ii.a	Table 3.5-2	Various Instrumentation Operational Details	(1)
15.ii.r	Table 3.5-4, Notes	ESFAS Instrumentation Design	(2)
15.ii.s	Table 3.5-4, Notes	ESFAS Instrumentation Design	(2)
15.iii.a	Table 3.5-3	Various Instrumentation Operational Details	(1)
44.i	5.1.1 & 5.1.2	Site	(2)
45.i	5.2.1, 5.2.2	Reactor Containment Penetrations	(2)
45.i	5.2.3	Containment Design Features	(2)
46.i	5.3.1.a & 5.3.1.c	Miscellaneous Reactor Core Design Features	(2)
46.iii	5.3.2	RCS Design Features	(2)
47.iii	5.4.3	SFP Region I Decay Time Limit	(2)
48.i	5.5	Waste Treatment Systems	(2)
50.ii	6.1.1 & 6.2.1	Management Titles	(1)(2)
52.i	6.4	Training	(1)(2)
57.ii	6.9.1.1	Startup Report	(2)

(1) From Attachment A, Section D of licensee's application dated May 26, 1995

TABLE 3
RELOCATED TO IST PROGRAM
(Changes controlled by Specification 5.5.8 and 10 CFR 50.55a(f))

ITEM #(1)	CTS #	DESCRIPTION
28.ii.c	Table 4.1-2, #7	Pressurizer Safety Valve Testing Frequency
28.ii.m	Table 4.1-2, #12	Fire Protection Pump Information
29.i	4.2	ISI/IST Program Information
32.ii	4.5.2.1	CS, SI & RHR Pump Head Limits
32.iii	4.5.2.2.c	Accumulator Check Valve Testing
35.i	4.8.1 & 4.8.2	AFW Pump Tests
35.ii	4.8.3	AFW Valve Tests
35.iii	4.8.4	SAFW Pump Tests
35.iv	4.8.5	SAFW Valve Tests
35.v	4.8.6	AFW & SAFW Tests
38.v	4.11.2.2	RHR Pump Testing in MODE 6

(1) From Attachment A, Section D of licensee's application dated May 26, 1995

TABLE 4
RELOCATED TO ISI PROGRAM
(Changes controlled by 10 CFR 50.55a(g))

ITEM #(1)	CTS #	DESCRIPTION
23.i	3.13	Snubbers
29.i	4.2.1	ISI/IST Program Information
41.i	4.14	Snubber Surveillance Program

(1) From Attachment A, Section D of licensee's application dated May 26, 1995

TABLE 5
RELOCATED TO ODCM
(Changes Controlled by Specification 5.5.1)

ITEM #[1]	CTS #	DESCRIPTION
15.iv	3.5.4 & Table 3.5-6	Radiation Accident Monitoring
15.viii	3.5.5 & Table 3.5-5	Radioactive Effluent Monitoring Instrumentation
19.i	3.9.1.1	Liquid Effluents Concentration
19.ii	3.9.1.2 & 3.9.2.4	Liquid Effluents Dose
19.iii	3.9.1.3	Liquid Waste Treatment
19.iv	3.9.2.1	Gaseous Wastes Dose Rate
19.v	3.9.2.2.a, 3.9.2.2.c, 3.9.2.4	Gaseous Wastes Dose
19.vi	3.9.2.2.b, 3.9.2.2.c, 3.9.2.4	Gaseous Waste Dose
19.vii	3.9.2.3	Gaseous Waste Treatment
19.ix	3.9.2.7	Solid Radioactive Waste
26.i	3.16.1 & Table 3.16-1	Radiological Environmental Monitoring Program
26.ii	3.16.2	Land Use Census
26.iii	3.16.3	Interlaboratory Comparison Program
28.i.j	Tbl. 4.1-1, #18, 28, 29	Radiation Monitoring Instrumentation
28.v.b	4.1.4 & Table 4.1-5	Radioactive Effluent Monitoring Surveillance Requirements
37.i	4.10.1 & Table 4.10-1	Radiological Environmental Monitoring
37.ii	4.10.2	Land Use Census
37.iii	4.10.3	Interlaboratory Comparison Program
39.i	4.12.1.1 & Table 4.12-1	Liquid Effluents Concentration
39.ii	4.12.1.2	Liquid Effluents Dose
39.iii	4.12.2.1 & Table 4.12-2	Gaseous Wastes Release Rate
39.iv	4.12.2.2	Gaseous Wastes Dose
39.v	4.12.3	Waste Decay Tanks
40.i	4.13	Radioactive Material Source Leakage Tests
57.iv	6.9.1.3, 6.9.1.4, Table 6.9-1, & Table 6.9-2	Administrative Control Reports

(1) From Attachment A, Section D of licensee's application dated May 26, 1995

TABLE 6
RELOCATED TO PLANT PROCEDURES
(Changes controlled by 10 CFR 50.59)

ITEM #(1)	CTS #	DESCRIPTION
18.ii	3.8.1.b	Radiation Levels in Containment
18.v	3.8.1.f	Control Room and Manipulator Crane Communications
18.vii	3.8.1.c	Containment Audible Flux Monitor
28.ii.n	Table 4.1-2, #18	Secondary Coolant Samples
28.v.b	Table 4.1.5, Note 5	CHANNEL CALIBRATION and National Bureau of Standards
31.i	4.4.4	Containment Tendon Surveillance
31.ii	4.4.3	Recirculation Heat Removal Systems
33.v	4.6.1.e.1	Diesel Inspections
32.v	4.5.2.3	Air Filtration Systems
33.x	4.6.2.c	Battery Test Trending
38.i, 38.ii	4.11.1.1	Spent Fuel Pool Charcoal Adsorber System
46.i	5.3.1.a	Reporting Requirements for Rod Filler Material
57.iii	6.9.1.2	Monthly Operating Report Database
65.i	6.17	Major changes to Radioactive Waste Treatment Systems

(1) From Attachment A, Section D of licensee's application dated May 26, 1995

TABLE 7
RELOCATED TO PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)
(Changes Controlled by Specification 5.6.6)

ITEM #(1)	CTS #	DESCRIPTION
6.v	3.1.1.1.k	LTOP Enable Temperature
7.i	3.1.2.1.a, Figure 3.1.1, & Figure 3.1-2	RCS Heatup and Cooldown Curves
7.v	3.1.2.3	Pressurizer Heatup and Cooldown Rates
25.ii	3.15.1	LTOP Setpoints

(1) From Attachment A, Section D of licensee's application dated May 26, 1995

TABLE 8
RELOCATED TO TECHNICAL REQUIREMENTS MANUAL (TRM)
(Changes Controlled by 10 CFR 50.59)

ITEM #(1)	CTS #	DESCRIPTION
6.xi	3.1.1.4, 3.1.1.6	Reactor Vessel Head Vents
11.i	3.1.6 & Table 4.1-2 #1 & #2	RCS Chemistry
12.ii	3.2.1 & 3.2.1.1	CVCS in MODES 5 and 6
12.iii	3.2.2 & 3.2.4	CVCS above MODE 5
12.iv	3.2.3 & Table 3.2-1	CVCS Boron Concentration
15.i.q	Table 3.5-1, #17	Circulating Water Flood Protection
15.ii	Table 3.5-2	SAFW Pumps
15.v	3.5.6.1	Control Room Toxic Gas Monitors
17.iii	3.7.2.1.b.2, 3.7.2.2.a, & 3.7.2.2.b	Second Offsite Power Source
20.xv	3.10.4.3.2.b.iii & Table 3.10-1	Misaligned Rod Accident Analysis Evaluation
21.ii	3.11.2	Fuel Movement Requirements in Aux Bldg
21.iii	3.11.3, 3.11.5	Fuel Movement Requirements in Aux Bldg
21.iv	3.11.4	Fuel Movement Requirements in Aux Bldg
22.i	3.12.1	Moveable Incore Instrumentation
28.i.g	Table 4.1-1, #34 & 35	Control Room Toxic Gas Monitors
28.i.m	Table 4.1-2, #14, 16, & 19	CVCS Surveillances
28.ii.d	Tbl. 4.1-2, #10	Fuel Movement Requirements in Aux Bldg
28.ii.h	Tbl. 4.1-2, #19	Circulating Water Flood Protection
28.ii.l	Tbl. 4.1-2, #4	CVCS Surveillances
30.i	4.3.5.6	Reactor Vessel Head Vent
33.vi	4.6.1.e.3(b)	DG Sequence Time Limits
47.iii	5.4.3	SFP Tornado Related Requirements
55.ii	6.7.1.b	Safety Limit Violation Response
55.iii	6.7.1.c	Safety Limit Violation Response
55.iv	6.7.1.d	Safety Limit Violation Response
56.ii	6.8.1.e	Process Control Program
54.i	6.16	Process Control Program

(1) From Attachment A, Section D of licensee's application dated May 26, 1995

TABLE 9
RELOCATED TO TECHNICAL SPECIFICATION BASES
(Changes controlled by Specification 5.5.13)

ITEM #[1]	CTS #	DESCRIPTION
13.ix	3.3.1.1.h, 4.3.3.3	PIV Listing
13.xii	3.3.1.7	SI Pump Listing
13.xii	3.3.1.8	SI Pump Listing
16.v	3.6.5	Mini-purge valves opening restrictions
None	3.11.1	ABVS Components
32.viii	4.6.2.f	Battery degradation definition
N/A	4.6.3.a.3	Tie Breakers
4.iv	2.3.3.1, 2.3.3.2, Figure 2.3-1	LSSS Voltage Setting

APPENDIX

Ginna Current Technical Specifications (CTS)				Ginna Improved Technical Specifications (ITS)		
Chapter Section	Section or LCO Title	Chapter Section	Surveillance Requirements Title - (1),(2),(3)	Chapter Section Manual	LCO Title	Remarks
1.0	Definitions	NA	-	1.0 --	Use/Application	
2.0	Safety Limits (SLs) & LSSSs	NA	-	2.0 -- 3.3 --	SLs & LSSSs Instrumentation	
3.0	Applicability	4.0 --	Surveillance Requirements	3.0 -- 3.8 --	Applicability Electrical System	
3.1	Reactor Coolant System (RCS)	4.2 4.3	Inservice Inspection RCS & Table 4.1-4	3.4 -- (4)	Reactor Coolant Systems	3.1, 3.2, 3.8, & 5.0
3.2	Chemical & Volume Control System	4.9 --	Reactivity Anomalies	3.1 --	Reactivity Control	
3.3	ECCS, Auxiliary Cooling Systems, Containment Spray, CRFCs	4.5 -- 4.8 --	SI,Containment Spray and Iodine Removal Tests Auxiliary Feedwater Tests	3.4 -- 3.5 -- 3.6 -- 3.7 --	RCS ECCS Systems Containment Systems Plant Systems	
3.4	Turbine Cycle	4.7 --	Main Steam Stop Valves	3.7 --	Plant Systems	
3.5	Instrumentation System	Many sections	Table 4.1-3, 4.4.6, 4.4.7, 4.8.9	3.3 -- (4)	Instrumentation Systems	5.0
3.6	Containment System	4.4 --	Containment Tests	3.6 -- (4)	Containment Systems	3.3, 3.9, & 5.0
3.7	Auxiliary Electrical Systems	4.6 --	Preferred & Emergency Power System Periodic Tests	3.8 --	Electrical Systems	
3.8	Refueling	4.11 --	Refueling	3.7 -- (4) 3.9 --	Plant Systems Refueling	5.0
3.9	Plant Effluents	4.12 --	Effluent Surveillance, Table 4.1-5	5.0 --	Admin. Controls Relocated ODCM	
3.10	Control Rod and Power Distribution Limits	NA	None	3.1 -- 3.2 --	Reactivity Control Power Distribution Limits	
3.11	Fuel Handling in the Aux Bldg	NA	None	3.7 --	Plant Systems	
3.12	Movable In-Core Instrumentation	NA	None	3.3 --	Instrumentation	
3.13	Shock Suppressors (Snubbers)	4.14 -- 4.13 --	Shock Suppressors (Snubbers) Rad Matl Leak Test	5.0 -- TRM	Admin Controls Relocated - TRM	
3.14	Deleted	4.15	Deleted			
3.15	Overpressure Protection Sys.	4.16	Overpressure Protection System	3.4	Reactor Coolant System	
3.16	Radiological Envir. Testing	4.10	Environmental Radiation Survey	5.0 --	Admin. Controls Relocated ODCM	
5.0	Design Features	NA	-	4.0	Design Features	
6.0	Administrative Controls	NA	-	5.0	Administrative Controls	

(1) - Section 4.1 is applicable to all Surveillance Requirements.
(2) - Table 4.1-1, Minimum Frequencies for Checks, Calibrations, Test of Instrument Channels, is applicable to most systems.
(3) - Table 4.1-2, Minimum Frequencies for Equipment and Sampling Tests, is applicable to most systems.
(4) - This annotates the location of smaller CTS requirements in the various other Chapters/Sections of the ITS, as shown in Remarks.

(continued)

(continued)

(continued)

(continued)

1.0 USE AND APPLICATION

1.1 Definitions

-----------------------------------NOTE-----------------------------------
The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
ACTUATION LOGIC TEST	An ACTUATION LOGIC TEST shall be the application of various simulated or actual input combinations in conjunction with each possible interlock logic state and the verification of the required logic output. The ACTUATION LOGIC TEST, as a minimum, shall include a continuity check of output devices.
AXIAL FLUX DIFFERENCE (AFD)	AFD shall be the difference in normalized flux signals between the top and bottom halves of a two section excore neutron detector.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel so that it responds within the required range and accuracy to known input. The CHANNEL CALIBRATION shall encompass the entire channel, including the required sensor, alarm, interlock, display, and trip functions. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping calibrations or total channel steps so that the entire channel is calibrated.

(continued)

1.1 Definitions (continued)

CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.
CHANNEL OPERATIONAL TEST (COT)	A COT shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify the OPERABILITY of required alarm, interlock, display, and trip functions. The COT shall include adjustments, as necessary, of the required alarm, interlock, and trip setpoints so that the setpoints are within the required range and accuracy.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is the plant specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific parameter limits shall be determined for each reload cycle in accordance with Specification 5.6.5. Plant operation within these limits is addressed in individual Specifications.
DOSE EQUIVALENT I-131	DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) that alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table E-7 of Regulatory Guide 1.109, Revision 1, 1977.

(continued)

1.1 Definitions (continued)

$\bar{E}$ – AVERAGE DISINTEGRATION ENERGY	$\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies (in MeV) per disintegration for non-iodine isotopes, with half lives > 15 minutes, making up at least 95% of the total non-iodine activity in the coolant.
LEAKAGE	LEAKAGE from the RCS shall be:

a. Identified LEAKAGE

1. LEAKAGE, such as that from pump seals or valve packing (except reactor coolant pump (RCP) seal water injection or return), that is captured and conducted to collection systems or a sump or collecting tank;

2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; or

3. Reactor Coolant System (RCS) LEAKAGE through a steam generator (SG) to the Secondary System;

b. Unidentified LEAKAGE

All LEAKAGE (except RCP seal water injection or return) that is not identified LEAKAGE;

c. Pressure Boundary LEAKAGE

LEAKAGE (except SG LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

(continued)

1.1 Definitions (continued)

MODE	A MODE shall correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE — OPERABILITY	A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in Chapter 14, Initial Test Program of the UFSAR; b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission (NRC).

(continued)

1.1 Definitions (continued)

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the plant specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, and the power operated relief valve lift settings and enable temperature associated with the Low Temperature Overpressurization Protection System for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6. Plant operation within these limits is addressed in individual specifications.
QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the highest average nuclear power in any quadrant to the average nuclear power in the four quadrants.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 1520 MWt.
SHUTDOWN MARGIN (SDM)	SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming: a. All rod cluster control assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. With any RCCAs not capable of being fully inserted, the reactivity worth of the RCCAs must be accounted for in the determination of SDM; and b. In MODES 1 and 2, the fuel and moderator temperatures are changed to the nominal hot zero power temperature.

(continued)

1.1 Definitions (continued)

STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.
TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT)	A TADOT shall consist of operating the trip actuating device and verifying the OPERABILITY of required alarm, interlock, display, and trip functions. The TADOT shall include adjustment, as necessary, of the trip actuating device so that it actuates at the required setpoint within the required accuracy.

Table 1.1-1 (page 1 of 1)
MODES

MODE	TITLE	REACTIVITY CONDITION (k_{eff})	% RATED THERMAL POWER[a]	AVERAGE REACTOR COOLANT TEMPERATURE (°F)
1	Power Operation	≥ 0.99	> 5	NA
2	Startup	≥ 0.99	≤ 5	NA
3	Hot Shutdown	< 0.99	NA	≥ 350
4	Hot Standby[b]	< 0.99	NA	$350 > T_{avg} > 200$
5	Cold Shutdown[b]	< 0.99	NA	≤ 200
6	Refueling[c]	NA	NA	NA

(a) Excluding decay heat.

(b) All reactor vessel head closure bolts fully tensioned.

(c) One or more reactor vessel head closure bolts less than fully tensioned.

1.0 USE AND APPLICATION

1.2 Logical Connectors

PURPOSE

The purpose of this section is to explain the meaning of logical connectors.

Logical connectors are used in Technical Specifications (TS) to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, and Frequencies. The only logical connectors that appear in TS are <u>AND</u> and <u>OR</u>. The physical arrangement of these connectors constitutes logical conventions with specific meanings.

BACKGROUND

Several levels of logic may be used to state Required Actions. These levels are identified by the placement (or nesting) of the logical connectors and by the number assigned to each Required Action. The first level of logic is identified by the first digit of the number assigned to a Required Action and the placement of the logical connector in the first level of nesting (i.e., left justified with the number of the Required Action). The successive levels of logic are identified by additional digits of the Required Action number and by successive indentations of the logical connectors.

When logical connectors are used to state a Condition, Completion Time or Frequency, only the first level of logic is used, and the logical connector is left justified with the statement of the Condition, Completion Time, or Frequency.

EXAMPLES

The following examples illustrate the use of logical connectors.

(continued)

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-1 LOGICAL CONNECTORS

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Verify . . . AND A.2 Restore . . .	

In this example the logical connector AND is used to indicate that when in Condition A, both Required Actions A.1 and A.2 must be completed.

(continued)

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-2 MULTIPLE LOGICAL CONNECTORS

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Trip . . . OR A.2.1 Verify . . . AND A.2.2.1 Reduce . . . OR A.2.2.2 Perform . . . OR A.3 Align . . .	

This example represents a more complicated use of logical connectors. Required Actions A.1, A.2, and A.3 are alternative choices, only one of which must be performed as indicated by the use of the logical connector OR and the left justified placement. Any one of these three Actions may be chosen. If A.2 is chosen, then both A.2.1 and A.2.2 must be performed as indicated by the logical connector AND. Required Action A.2.2 is met by performing A.2.2.1 or A.2.2.2. The indented position of the logical connector OR indicates that A.2.2.1 and A.2.2.2 are alternative choices, only one of which must be performed.

1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE	The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.
BACKGROUND	Limiting Conditions for Operation (LCOs) specify minimum requirements for ensuring safe operation of the plant. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).
DESCRIPTION	The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the plant is in a MODE or specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the plant is not within the LCO Applicability. If situations are discovered that require entry into more than one Condition at a time within a single LCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition. Once a Condition has been entered, subsequent trains, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will <u>not</u> result in separate entry into the Condition, unless specifically stated. The Required Actions of the Condition continue to apply to each additional failure, with Completion Times based on initial entry into the Condition.

(continued)

1.3 Completion Times

DESCRIPTION (continued)

However, when a <u>subsequent</u> train, subsystem, component, or variable expressed in the Condition is discovered to be inoperable or not within limits, the Completion Time(s) may be extended. The Completion time extension cannot be used to extend the stated Completion Time for the first inoperable train, subsystem, component, or variable. To apply this Completion Time extension, two criteria must first be met. The subsequent inoperability:

a. Must exist concurrent with the <u>first</u> inoperability; and

b. Must remain inoperable or not within limits after the first inoperability is resolved.

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours; or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extensions do not apply to those Specifications that have exceptions that allow completely separate re-entry into the Condition (for each train, subsystem, component, or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual Specifications.

(continued)

1.3 Completion Times

DESCRIPTION (continued)

The above Completion Time extension does not apply to a Completion Time with a modified "time zero." This modified "time zero" may be expressed as a repetitive time (i.e., "once per 8 hours," where the Completion Time is referenced from a previous completion of the Required Action versus the time of Condition entry). An example of a modified "time zero" with the Completion Time expressed as "once per 8 hours" is illustrated in Example 1.3-6, Condition A. In this example, the Completion Time may not be extended.

EXAMPLES

The following examples illustrate the use of Completion Times with different types of Conditions and changing Conditions.

EXAMPLE 1.3-1 COMPLETION TIMES

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

Condition B has two Required Actions. Each Required Action has its own separate Completion Time. Each Completion Time is referenced to the time that Condition B is entered.

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-2 DEFAULT CONDITIONS/LCO 3.0.3 ENTRY/COMPLETION TIMES

The Required Actions of Condition B are to be in MODE 3 within 6 hours AND in MODE 5 within 36 hours. A total of 6 hours is allowed for reaching MODE 3 and a total of 36 hours (not 42 hours) is allowed for reaching MODE 5 from the time that Condition B was entered. If MODE 3 is reached within 3 hours, the time allowed for reaching MODE 5 is the next 33 hours because the total time allowed for reaching MODE 5 is 36 hours.

If Condition B is entered while in MODE 3, the time allowed for reaching MODE 5 is the next 36 hours.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One train inoperable.	A.1 Restore train to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

When a train is declared inoperable, Condition A is entered. If the train is not restored to OPERABLE status within 7 days, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable train is restored to OPERABLE status after Condition B is entered, Condition A and B are exited, and therefore, the Required Actions of Condition B may be terminated.

(continued)

1.3 Completion Times

EXAMPLES

<u>EXAMPLE 1.3-2</u> (continued)

When a second train is declared inoperable while the first train is still inoperable, Condition A is not re-entered for the second train. LCO 3.0.3 is entered, since the ACTIONS do not include a Condition for more than one inoperable train. The Completion Time clock for Condition A does not stop after LCO 3.0.3 is entered, but continues to be tracked from the time Condition A was initially entered.

While in LCO 3.0.3, if one of the inoperable trains is restored to OPERABLE status and the Completion Time for Condition A has not expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition A.

While in LCO 3.0.3, if one of the inoperable trains is restored to OPERABLE status and the Completion Time for Condition A has expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition B. The Completion Time for Condition B is tracked from the time the Condition A Completion Time expired.

Upon restoring one of the trains to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first train was declared inoperable. This Completion Time may be extended if the train restored to OPERABLE status was the first inoperable train. A 24 hour extension to the stated 7 days is allowed, provided this does not result in the second train being inoperable for $>$ 7 days.

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-3 MULTIPLE FUNCTION COMPLETION TIMES

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X train inoperable.	A.1 Restore Function X train to OPERABLE status.	7 days
B. One Function Y train inoperable.	B.1 Restore Function Y train to OPERABLE status.	72 hours
C. One Function X train inoperable. AND One Function Y train inoperable.	C.1 Restore Function X train to OPERABLE status. OR C.2 Restore Function Y train to OPERABLE status.	72 hours 72 hours

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-3 (continued)

When one Function X train and one Function Y train are inoperable, Condition A and Condition B are concurrently applicable. The Completion Times for Condition A and Condition B are tracked separately for each train starting from the time each train was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked from the time the second train was declared inoperable (i.e., the time the situation described in Condition C was discovered).

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A. The remaining Completion Time in Condition A is measured from the time the affected train was declared inoperable (i.e., initial entry into Condition A).

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-4 MULTIPLE FUNCTION COMPLETION TIMES

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

A single Completion Time is used for any number of valves inoperable at the same time. The Completion Time associated with Condition A is based on the initial entry into Condition A and is not tracked on a per valve basis. Declaring subsequent valves inoperable, while Condition A is still in effect, does not trigger the tracking of separate Completion Times.

Once one of the valves has been restored to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first valve was declared inoperable. The Completion Time may be extended if the valve restored to OPERABLE status was the first inoperable valve. The Condition A Completion Time may be extended for up to 4 hours provided this does not result in any subsequent valve being inoperable for > 4 hours.

If the Completion Time of 4 hours (plus the extension) expires while one or more valves are still inoperable, Condition B is entered.

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-5 SEPARATE ENTRY CONDITION

ACTIONS

---------------------------NOTE---------------------------
Separate Condition entry is allowed for each inoperable valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

The Note above the ACTIONS table is a method of modifying how the Completion Time is tracked. If this method of modifying how the Completion Time is tracked was applicable only to a specific condition, the Note would appear in that Condition, rather than at the top of the ACTIONS table.

The Note allows Condition A to be entered separately for each inoperable valve, and Completion Times tracked on a per valve basis. When a valve is declared inoperable, Condition A is entered and its Completion Time starts. If subsequent valves are declared inoperable, Condition A is entered for each valve and separate Completion Times start and are tracked for each valve.

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-5 (continued)

If the Completion Time associated with a valve in Condition A expires, Condition B is entered for that valve. If the Completion Times associated with subsequent valves in Condition A expire, Condition B is entered separately for each valve and separate Completion Times start and are tracked for each valve. If a valve that caused entry into Condition B is restored to OPERABLE status, Condition B is exited for that valve.

Since the Note in this example allows multiple Condition entry and tracking of separate Completion Times, Completion Time extensions do not apply.

EXAMPLE 1.3-6 MULTIPLE ACTIONS WITHIN A CONDITION/COMPLETION TIME EXTENSIONS

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One channel inoperable.	A.1 Perform SR 3.x.x.x. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-6 (continued)

Entry into Condition A offers a choice between Required Action A.1 or A.2. Required Action A.1 has a "once per" Completion Time, which qualifies for the 25% extension, per SR 3.0.2, to each performance after the initial performance. The initial 8 hour interval of Required Action A.1 begins when Condition A is entered, and the initial performance of Required Action A.1 must be completed within the first 8 hour interval. If Required Action A.1 is followed, and the Required Action is not met within the Completion Time (plus the extension allowed by SR 3.0.2), Condition B is entered. If Required Action A.2 is followed and the Completion Time of 8 hours is not met, Condition B is entered.

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-7 MULTIPLE ACTIONS WITHIN A CONDITION/COMPLETION TIME EXTENSIONS

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore subsystem to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

Required Action A.1 has two Completion Times. The 1 hour Completion Time begins at the time the Condition is entered and each "Once per 8 hours thereafter" interval begins upon performance of Required Action A.1.

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-7 (continued)

If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour or any subsequent 8 hour interval from the previous performance (plus the extension allowed by SR 3.0.2), Condition B is entered. The Completion Time clock for Condition A does not stop after Condition B is entered, but continues from the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

IMMEDIATE COMPLETION TIME

When "Immediately" is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner.

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE

The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated LCO. An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR as well as certain Notes in the Surveillance column that modify performance requirements.

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

(continued)

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-1 SINGLE FREQUENCY

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the stated Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the plant is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the plant is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Example 1.4-3), then SR 3.0.3 becomes applicable.

If the interval as specified by SR 3.0.2 is exceeded while the plant is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, the Surveillance must be performed within the Frequency requirements of SR 3.0.2 prior to entry into the MODE or other specified condition. Failure to do so would result in a violation of SR 3.0.4.

(continued)

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-2 MULTIPLE FREQUENCIES

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify flow is within limits.	Once within 12 hours after ≥ 25% RTP AND 24 hours thereafter

Example 1.4-2 has two Frequencies. The first is a one time performance Frequency, and the second is of the type shown in Example 1.4-1. The logical connector "AND" indicates that both Frequency requirements must be met. Each time reactor power is increased from a power level < 25% RTP to ≥ 25% RTP, the Surveillance must be performed within 12 hours.

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the 1.25 times the stated Frequency extension allowed by SR 3.0.2. "Thereafter" indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

(continued)

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-3 FREQUENCY BASED ON SPECIFIED CONDITION

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-------------------NOTE------------------- Required to be performed within 12 hours after ≥ 25% RTP. --	
Perform channel adjustment.	7 days

The interval continues, whether or not the plant operation is < 25% RTP between performances.

As the Note modifies the required performance of the Surveillance, it is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is < 25% RTP, this Note allows 12 hours after power reaches ≥ 25% RTP to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency." Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was < 25% RTP, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not exceed 12 hours with power ≥ 25% RTP.

Once the plant reaches 25% RTP, 12 hours would be allowed for completing the Surveillance. If the Surveillance were not performed within this 12 hour interval, there would then be a failure to perform a Surveillance within the specified Frequency and the provisions of SR 3.0.3 would apply.

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

In MODES 1 and 2, the combination of THERMAL POWER, Reactor Coolant System (RCS) average temperature, and pressurizer pressure shall not exceed the SLs specified in Figure 2.1.1-1.

2.1.2 RCS Pressure SL

In MODES 1, 2, 3, 4, and 5, the RCS pressure shall be maintained ≤ 2735 psig.

2.2 SL Violations

2.2.1 If SL 2.1.1 is violated, restore compliance and be in MODE 3 within 1 hour.

2.2.2 If SL 2.1.2 is violated:

2.2.2.1 In MODE 1 or 2, restore compliance and be in MODE 3 within 1 hour.

2.2.2.2 In MODE 3, 4, or 5, restore compliance within 5 minutes.

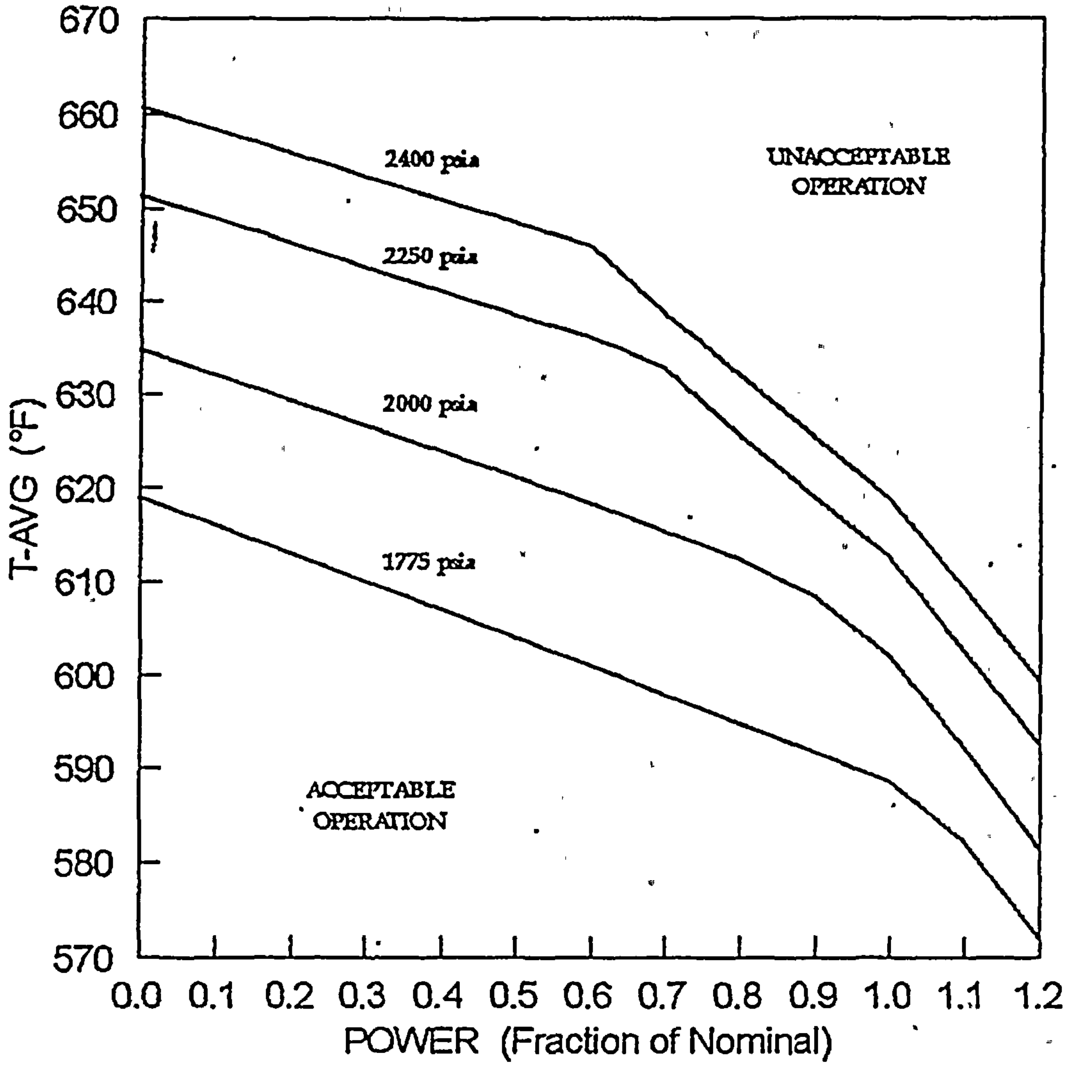


Figure 2.1.1-1
Reactor Safety Limits

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

Atomic Industrial Forum (AIF) GDC 6 (Ref. 1) requires that the reactor core shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. This integrity is required during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur on the limiting fuel rods and by requiring that fuel centerline temperature stays below the melting temperature (Ref. 2).

The restrictions of this SL prevent overheating of the fuel and cladding, as well as possible cladding perforation, that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak linear heat rate (LHR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant.

(continued)

BASES

BACKGROUND (continued)

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium - water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The proper functioning of the Reactor Protection System (RPS) and main steam safety valves prevents violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria (Ref. 3):

a. The hot fuel pellet in the core must not experience centerline fuel melting; and

b. There must be at least 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

In meeting the DNB design criterion, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters and computer codes must be considered. The effects of these uncertainties have been statistically combined with the correlation uncertainty to determine design limit departure from nucleate boiling ratio (DNBR) values that satisfy the DNB design criterion. The observable parameters, thermal power, reactor coolant temperature and pressure have been related to DNB through the W-3 and/or WRB-1 DNB correlation. These DNB correlations have been developed to predict the DNB flux and the location of DNB for auxiliary uniform and non-uniform heat flux distributions. The local DNB heat flux ratio, defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, is indicative of the margin to DNB. A minimum value of the DNB ratio is specified so that during steady state operation, normal operational transients and anticipated transients, there is a 95% probability at a 95% confidence level that DNB will not occur. The curves of Figure 2.1.1-1 represent the loci of points of thermal power, coolant system pressure and average temperature for which this minimum DNB value is satisfied. The area of safe operation is at or below these lines. Safe operation relative to Figure 2.1.1-1 refers to transient or accident conditions. Normal steady state operation is governed by LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits."

Additional DNBR margin is maintained by performing the safety analyses to a higher DNBR limit. This margin between the design and safety analysis limit DNBR values is used to offset known DNBR penalties (e.g., rod bow and transition core) and to provide DNBR margin for operating and design flexibility (Ref. 4).

The Reactor Trip System setpoints specified in LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation", in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressurizer pressure, and THERMAL POWER level that would result in a DNBR of less than the DNBR limit and preclude the existence of flow instabilities.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

Automatic enforcement of these reactor core SLs is provided by the following functions (Ref. 5):

a. High pressurizer pressure trip;

b. Low pressurizer pressure trip;

c. Overtemperature ΔT trip;

d. Overpower ΔT trip;

e. Power Range Neutron Flux trip; and

f. Steam generator safety valves.

Additional anticipatory trip functions are also provided for specific abnormal conditions.

The SLs represent a design requirement for establishing the RPS trip setpoints identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses (Ref. 6) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

Figure B 2.1.1-1 shows an example of the reactor core safety limits of THERMAL POWER, RCS pressure, and average temperature for which the minimum DNBR is greater than or equal to the safety analyses limit, that fuel centerline temperature remains below melting, that the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid, or that the core exit quality is within the limits defined by the DNBR correlation. From this type of figure, the curves on Figure 2.1.1-1 of the accompanying specification can be generated. Each of the curves of Figure 2.1.1-1 has three distinct slopes. Working from left to right, the first slope ensures that the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid such that overtemperature ΔT indication remains valid. The second slope ensures that the hot leg steam quality remains ≤ 15% as required by W-3 correlation. The final slope ensures that DNBR is always ≥ 1.3.

(continued)

BASES

SAFETY LIMITS (continued)

The SL is higher than the limit calculated when the Axial Flux Difference (AFD) is within the limits of the F(ΔI) function of the overtemperature ΔT reactor trip. When the AFD is not within the tolerance, the AFD effect on the overtemperature ΔT reactor trips will reduce the setpoints to provide protection consistent with the reactor core SLs.

APPLICABILITY

SL 2.1.1 only applies in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The steam generator safety valves and automatic protection actions serve to prevent RCS heatup to the reactor core SL conditions or to initiate a reactor trip function, which forces the plant into MODE 3. Setpoints for the reactor trip functions are specified in LCO 3.3.1. In MODES 3, 4, 5, and 6, Applicability is not required since the reactor is not generating significant THERMAL POWER.

SAFETY LIMIT VIOLATIONS

If SL 2.1.1 is violated, the requirement to restore compliance and go to MODE 3 places the plant in a safe condition and in a MODE in which this SL is not applicable.

The allowed Completion Time of 1 hour recognizes the importance of bringing the plant to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage. If the Completion Time is exceeded, actions shall continue in order to bring the plant to a MODE of operation where this SL is not applicable.

(continued)

BASES (continued)

REFERENCES

1. Atomic Industrial Forum (AIF) GDC 6, Issued for comment July 10, 1967.

2. Letter from J. A. Zwolinski, NRC, to R. W. Kober, RG&E, Subject: "Deletion of Information Pertaining to Definition of Hot Channel Factors," dated May 30, 1985.

3. UFSAR, Section 4.2.1.3.3.

4. UFSAR, Section 4.4.3.

5. WCAP-8745, "Design Bases for the Thermal Overpower Delta T and Thermal Overtemperature Delta T Trip Functions," March 1977.

6. UFSAR, Section 7.2.1.1.1.

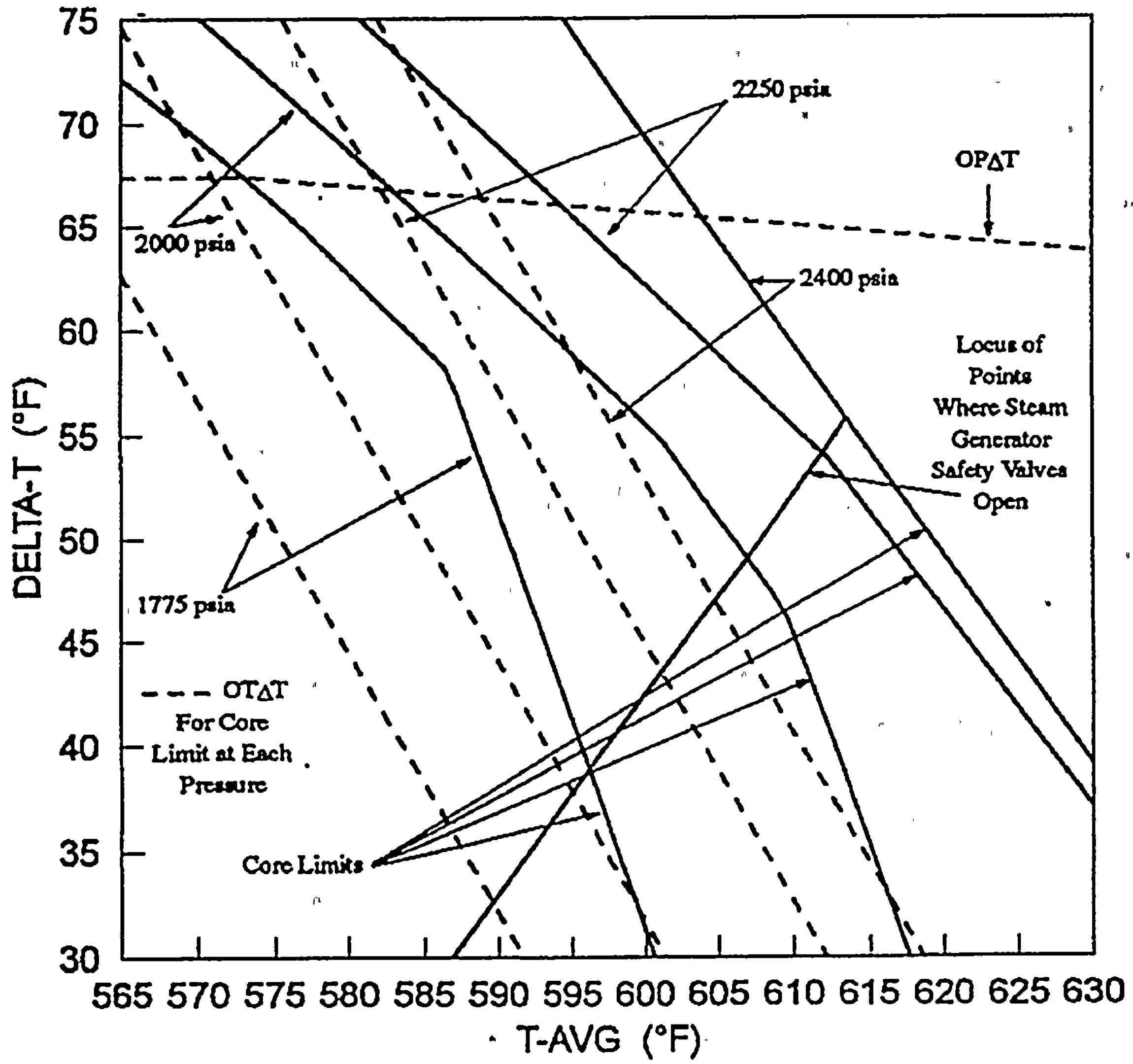


Figure B 2.1.1-1
Reactor Core Safety Limits vs. Boundary of Protection

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on RCS pressure protects the integrity of the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. By establishing an upper limit on RCS pressure, the continued integrity of the RCS is ensured. According to Atomic Industrial Forum (AIF) GDC 9, "Reactor Coolant Pressure Boundary," GDC 33, "Reactor Coolant Pressure Boundary Capability," and GDC 34, "Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention" (Ref. 1), the reactor coolant pressure boundary (RCPB) design conditions are not to be exceeded during normal operation and anticipated operational occurrences (AOOs).

The design pressure of the RCS is 2485 psig (Ref. 2). During normal operation and AOOs, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 3) except for locked rotor accidents which must be limited to 120% of the design pressure (Refs. 4, 5, and 6). To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure, according to the ASME Code requirements prior to initial operation when there is no fuel in the core. Following inception of plant operation, RCS components are pressure tested, in accordance with the requirements of the approved Ginna ISI/IST Program which is based on ASME Code, Section XI (Ref. 7).

Overpressurization of the RCS could result in a breach of the RCPB reducing the number of protective barriers designed to prevent radioactive releases from exceeding the limits specified in 10 CFR 100, "Reactor Site Criteria" (Ref. 8). If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The RCS pressurizer safety valves, the main steam safety valves (MSSVs), and the reactor high pressure trip have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressurizer safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, as specified in Section III of the ASME Code for Nuclear Power Plant Components (Ref. 3) except for locked rotor accidents which must be limited to 120% of the design pressure. The transient that establishes the required relief capacity, and hence valve size requirements and lift settings, is a complete loss of external load without a direct reactor trip. During the transient, no control actions are assumed, except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve settings.

The Reactor Trip System setpoints (Ref. 9), together with the settings of the MSSVs, provide pressure protection for normal operation and AOOs. The reactor high pressure trip setpoint is specifically set to provide protection against overpressurization. The safety analyses which credit either the high pressure trip or the RCS pressurizer safety valves are performed using conservative assumptions relative to the other pressure control devices.

More specifically, no credit is taken for operation of the following:

a. Pressurizer power operated relief valves;

b. Steam generator atmospheric relief valves;

c. Steam Dump System;

d. Reactor Control System;

e. Pressurizer Level Control System; or

f. Pressurizer spray valves.

(continued)

BASES (continued)

SAFETY LIMITS

The maximum transient pressure allowed in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure except for locked rotor accidents which must be limited to 120% of the design pressure. The maximum transient pressure allowed in the RCS piping, valves, and fittings under the original design requirements of USAS B31.1 (Ref. 5) is 120% of design pressure. The most limiting of these two allowances is the 110% of design pressure; therefore, the SL on maximum allowable RCS pressure is 2735 psig.

APPLICABILITY

SL 2.1.2 applies in MODES 1, 2, 3, 4, and 5 because this SL could be approached or exceeded in these MODES due to overpressurization events. The SL is not applicable in MODE 6 because the reactor vessel head closure bolts are not fully tightened, making it unlikely that the RCS can be pressurized.

SAFETY LIMIT VIOLATIONS

If SL 2.1.2 is violated when the reactor is in MODE 1 or 2, the requirement is to restore compliance and be in MODE 3 within 1 hour.

Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 8).

The allowable Completion Time of 1 hour recognizes the importance of reducing power level to a MODE of operation where the potential for challenges to safety systems is minimized. If the Completion Time is exceeded, actions shall continue in order to restore compliance with the SL and bring the plant to MODE 3.

(continued)

BASES

SAFETY LIMIT VIOLATIONS (Continued)

If SL 2.1.2 is exceeded in MODE 3, 4, or 5, RCS pressure must be restored to within the SL value within 5 minutes. Exceeding the RCS pressure SL in MODE 3, 4, or 5 is more severe than exceeding this SL in MODE 1 or 2, since the reactor vessel temperature may be lower and the vessel material, consequently, less ductile. As such, pressure must be reduced to less than the SL within 5 minutes. If the Completion Time is exceeded, action shall continue in order to reduce pressure to less than the SL. The action does not require reducing MODES, since this would require reducing temperature, which would compound the problem by adding thermal gradient stresses to the existing pressure stress.

REFERENCES

1. Atomic Industrial Forum (AIF) GDC 9, 33, and 34, Issued for comment July 10, 1967.
2. UFSAR, Section 5.1.4.
3. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000.
4. Letter from D. M. Crutchfield, NRC, to J. E. Maier, RG&E, Subject: "SEP Topic XV-1, XV-2, XV-3, XV-4, XV-5, XV-6, XV-7, XV-8, XV-10, XV-12, XV-14, XV-15, and XV-17, Design Basis Events, Accidents and Transients (R.E. Ginna)," dated September 4, 1981.
5. USAS B31.1, Standard Code for Pressure Piping, American Society of Mechanical Engineers, 1967 edition.
6. UFSAR, Section 15.3.2.
7. ASME, Boiler and Pressure Vessel Code, Section XI.
8. 10 CFR 100.
9. UFSAR, Section 7.2.2.2.

3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1 LCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in LCO 3.0.2 and 3.0.7.

LCO 3.0.2 Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met, except as provided in LCO 3.0.5 and LCO 3.0.6.

If the LCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required unless otherwise stated.

LCO 3.0.3 When an LCO is not met and (1) the associated ACTIONS are not met, (2) an associated ACTION is not provided, or (3) if directed by the associated ACTIONS, the plant shall be placed in a MODE or other specified condition in which the LCO is not applicable. Action shall be initiated to place the plant, as applicable, in:

a. MODE 3 within 6 hours;

b. MODE 4 within 12 hours; and

c. MODE 5 within 36 hours.

Exceptions to this Specification are stated in the individual Specifications.

Where corrective measures are completed that permit operation in accordance with the LCO or ACTIONS, completion of the actions required by LCO 3.0.3 is not required.

LCO 3.0.3 is only applicable in MODES 1, 2, 3, and 4.

(continued)

3.0 LCO APPLICABILITY (continued)

LCO 3.0.4 When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall not be made except when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. This Specification shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS.

Exceptions to this Specification are stated in the individual Specifications.

LCO 3.0.5 Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the testing required to determine OPERABILITY.

LCO 3.0.6 When a supported system LCO is not met solely due to a support system LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system LCO ACTIONS are required to be entered. This is an exception to LCO 3.0.2 for the supported system. In this event, additional evaluations and limitations may be required in accordance with Specification 5.5.14, "Safety Function Determination Program (SFDP)." If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

When a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

(continued)

3.0 LCO APPLICABILITY (continued)

LCO 3.0.7 Test Exception LCO 3.1.8, "PHYSICS TEST Exceptions - MODE 2," allows specified Technical Specification (TS) requirements to be changed to permit performance of special tests and operations. Unless otherwise specified, all other TS requirements remain unchanged. When a Test Exception LCO is desired to be met but is not met, the ACTIONS of the Test Exception LCO shall be met. When a Test Exception LCO is not desired to be met, entry into a MODE or other specified condition in the Applicability shall be made in accordance with the other applicable Specifications.

3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

SR 3.0.1

SRs shall be met during the MODES or other specified conditions in the Applicability for individual LCOs, unless otherwise stated in the SR. Failure to meet a SR, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the LCO. Failure to perform a Surveillance within the specified Frequency shall be failure to meet the LCO except as provided in SR 3.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

SR 3.0.2

The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met.

For Frequencies specified as "once," the above interval extension does not apply.

If a Completion Time requires periodic performance on a "once per . . ." basis, the above Frequency extension applies to each performance after the initial performance.

Exceptions to this Specification are stated in the individual Specifications.

SR 3.0.3

If it is discovered that a Surveillance was not performed within its specified Frequency, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Frequency, whichever is less. This delay period is permitted to allow performance of the Surveillance.

If the Surveillance is not performed within the delay period, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

(continued)

3.0 SR APPLICABILITY

SR 3.0.3 (continued)	When the Surveillance is performed within the delay period and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.
SR 3.0.4	Entry into a MODE or other specified condition in the Applicability of an LCO shall not be made unless the LCO's Surveillances have been met within their specified Frequency. This provision shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.7 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.
LCO 3.0.1	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the plant is in the MODES or other specified conditions of the Applicability statement of each Specification).
LCO 3.0.2	LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that: a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified.

(continued)

BASES

LCO 3.0.2 (continued)

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the plant in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the plant that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Condition no longer exists. In this instance, the individual LCO's ACTIONS specify the Required Actions. An example of this is in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits."

(continued)

BASES

LCO 3.0.2 (continued)

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems as required by the LCO. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Alternatives that would not result in redundant equipment being inoperable should be used instead. Doing so limits the time both subsystems/trains of a safety function are inoperable and limits the time other conditions exist which may result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the plant may enter a MODE or other specified condition in which another Specification becomes applicable and the new LCO is not met. In this case, the Completion Times of the new Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

(continued)

BASES

LCO 3.0.3 (continued)

b. The condition of the plant is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the plant. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

This Specification delineates the time limits for placing the plant in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

(continued)

BASES

LCO 3.0.3 (continued)

Upon entering LCO 3.0.3, the Shift Supervisor shall evaluate the condition of the plant and determine actions to be taken, considering plant safety first, that will allow sufficient time for an orderly plant shutdown. These actions shall include preparation for a safe and controlled shutdown, as well as actions to correct the condition which caused entry into LCO 3.0.3. If it is determined that the condition that caused entry into LCO 3.0.3 can be corrected within a reasonable period of time and still allow sufficient time for an orderly plant shutdown, a power reduction does not have to be initiated. This includes coordinating the reduction in electrical generation with energy operations to ensure the stability and availability of the electrical grid. The shutdown shall be initiated so that the time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the plant, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, Completion Times.

A plant shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met.

b. A Condition exists for which the Required Actions have now been performed.

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.3 is exited.

(continued)

BASES

LCO 3.0.3 (continued)

The time limits of LCO 3.0.3 allow 36 hours for the plant to be in MODE 5 when a shutdown is required during MODE 1 operation. If the plant is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is reached in 2 hours, then the time allowed for reaching MODE 4 is the next 10 hours, because the total time for reaching MODE 4 is not reduced from the allowable limit of 12 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the plant is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a plant shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the plant. An example of this is in LCO 3.7.11, "Spent Fuel Pool (SFP) Water Level." LCO 3.7.11 has an Applicability of "During movement of irradiated fuel assemblies in the SFP." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.11 are not met while in MODE 1, 2, 3, or 4, there is no safety benefit to be gained by placing the plant in a shutdown condition. The Required Action of LCO 3.7.11 of "Suspend movement of irradiated fuel assemblies in the SFP" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

(continued)

BASES

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It precludes placing the plant in a different MODE or other specified condition stated in the Applicability when the following exist:

a. Plant conditions are such that the requirements of an LCO would not be met in the MODE or other specified condition in the Applicability desired to be entered; and

b. The plant would be required to exit the MODE or other specified condition in the Applicability desired to be entered in order to comply with the Required Actions of the affected LCO.

Compliance with Required Actions that permit continued operation of the plant for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the plant before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from a shutdown performed in response to the expected failure to comply with ACTIONS.

Exceptions to LCO 3.0.4 are stated in the individual Specifications. The exceptions allow entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time. Exceptions may apply to all the ACTIONS or to a specific Required Action of a Specification.

(continued)

BASES

LCO 3.0.4 (continued)

LCO 3.0.4 is applicable when entering all MODES, whether increasing in MODES (e.g., MODE 5 to MODE 4) or decreasing in MODES (e.g., MODE 4 to MODE 5). This requirement precluding entry into another MODE when the associated ACTIONS do not provide for continued operation for an unlimited period of time ensures that the plant maintains sufficient equipment OPERABILITY and redundancy as assumed in the accident analyses.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, changing MODES or other specified conditions while in an ACTIONS Condition, in compliance with LCO 3.0.4 or where an exception to LCO 3.0.4 is stated, is not a violation of SR 3.0.1 or SR 3.0.4 for those Surveillances that do not have to be performed due to the associated inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

LCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this LCO is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of SRs to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the allowed SRs. This Specification does not provide time to perform any other preventive or corrective maintenance.

(continued)

BASES

LCO 3.0.5 (continued)

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the SRs.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of an SR on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of an SR on another channel in the same trip system.

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support systems' LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCO's Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's Required Actions.

(continued)

BASES

LCO 3.0.6 (continued)

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.14, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required. The cross train check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

(continued)

BASES

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the plant. These special tests and operations are necessary to demonstrate select plant performance characteristics, to perform special maintenance activities, and to perform special evolutions. Test Exception LCO 3.1.8, "PHYSICS TEST Exceptions - MODE 2," allows specified Technical Specification (TS) requirements to be changed to permit performances of special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. A special operation may be performed either under the provisions of the appropriate Test Exception LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known not to be met between required Surveillance performances.

Surveillances do not have to be performed when the plant is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a test exception are only applicable when the Test Exception LCO is used as an allowable exception to the requirements of a Specification.

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

(continued)

BASES

SR 3.0.1 (continued)

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary plant parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per . . ." interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

(continued)

BASES

SR 3.0.2 (continued)

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. Therefore, when a test interval is specified in the regulations, the test interval cannot be exceeded by TS, and the SR includes a Note in the Frequency stating, "SR 3.0.2 is not applicable." An example of an exception when the test interval is not specified in the regulations is the Note in the Containment Leakage Rate Testing Program, "SR 3.0.2 is not applicable." This exception is provided because the program already includes extension of test intervals.

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per ..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with Refueling intervals) or periodic Completion Time intervals beyond those specified.

(continued)

BASES

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is less, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of plant conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Frequency based not on time intervals, but upon specified plant conditions or operational situations, is discovered not to have been performed when specified, SR 3.0.3 allows the full delay period of 24 hours to perform the Surveillance.

SR 3.0.3 also provides a time limit for completion of Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

(continued)

BASES

SR 3.0.3 (continued)

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the plant. This Specification applies to changes in MODES or other specified conditions in the Applicability associated with plant shutdown as well as startup.

The provisions of this specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from a shutdown performed in response to the expected failure to comply with ACTIONS.

(continued)

BASES

SR 3.0.4 (continued)

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, train, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency, on equipment that is inoperable, does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes.

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO Applicability, would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, Frequency.

SR 3.0.4 is applicable when entering all MODES, whether increasing in MODES (e.g., MODE 5 to MODE 4) or decreasing in MODES (e.g., MODE 4 to MODE 5). This requirement precluding entry into another MODE when the associated ACTIONS do not provide for continued operation for an unlimited period of time ensures that the plant maintains sufficient equipment OPERABILITY and redundancy as assumed in the accident analyses.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.1 SHUTDOWN MARGIN (SDM)

LCO 3.1.1 SDM shall be within the limits specified in the COLR.

APPLICABILITY: MODE 2 with $k_{eff} < 1.0$,
MODES 3, 4, and 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.1.1.1 Verify SDM is within the limits specified in the COLR.	24 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.2 Core Reactivity

LCO 3.1.2 The measured core reactivity shall be within ± 1% Δk/k of predicted values.

APPLICABILITY: MODE 1,
MODE 2 with $K_{eff} \geq 1.0$.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Measured core reactivity not within limit.	A.1	Re-evaluate core design and safety analysis, and determine that the reactor core is acceptable for continued operation.	72 hours
	<u>AND</u>		
	A.2	Establish appropriate operating restrictions and SRs.	72 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 2 with $K_{eff} < 1.0$.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.2.1	-------------------NOTE------------------- Required to be performed prior to entering MODE 1. -- Verify measured core reactivity is within ± 1% Δk/k of predicted values.	Once after each refueling
SR 3.1.2.2	------------------NOTES------------------ 1. Only required after 60 effective full power days (EFPD). 2. The predicted reactivity values must be adjusted (normalized) to correspond to the measured core reactivity prior to exceeding a fuel burnup of 60 EFPD after each fuel loading. -- Verify measured core reactivity is within ± 1% Δk/k of predicted values.	31 EFPD

3.1 REACTIVITY CONTROL SYSTEMS

3.1.3 Moderator Temperature Coefficient (MTC)

LCO 3.1.3 The MTC shall be maintained within the limits specified in the COLR. The maximum upper limit shall be less than or equal to 5 pcm/°F for power levels below 70% RTP and less than or equal to 0 pcm/°F at or above 70% RTP.

APPLICABILITY: MODE 1 and MODE 2 with $k_{eff} \geq 1.0$ for the upper MTC limit, MODES 1, 2, and 3 for the lower MTC limit.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. MTC not within upper limit.	A.1	Establish administrative withdrawal limits for control banks to maintain MTC within limit.	24 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 2 with $k_{eff} < 1.0$.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------NOTE--------- Required Action C.1 must be completed whenever Condition C is entered. ---------------------- Projected end of cycle life (EOL) MTC not within lower limit.	-------------NOTE------------ LCO 3.0.4 is not applicable. ---------------------------- C.1 Re-evaluate core design and safety analysis, and determine that the reactor core is acceptable for continued operation.	Once prior to reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	Verify MTC is within upper limit.	Once prior to entering MODE 1 after each refueling
SR 3.1.3.2	Confirm that MTC will be within limits at 70% RTP.	Once prior to entering MODE 1 after each refueling

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.3.3	Confirm that MTC will be within limits at EOL.	Once prior to entering MODE 1 after each refueling.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.4 Rod Group Alignment Limits

LCO 3.1.4 All shutdown and control rods shall be OPERABLE, with all individual indicated rod positions within 12 steps of their group step counter demand position.

APPLICABILITY: MODE 1,
MODE 2 with $K_{eff} \geq 1.0$.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more rod(s) untrippable.	A.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	<u>OR</u>	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	
	A.2 Be in MODE 2 with $K_{eff} < 1.0$.	6 hours
B. One rod not within alignment limits.	B.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	<u>OR</u>	
	B.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	Reduce THERMAL POWER to ≤ 75% RTP.	2 hours
	<u>AND</u>		
	B.3	Verify SDM is within the limits specified in the COLR.	Once per 12 hours
	<u>AND</u>		
	B.4	Perform SR 3.2.1.1.	72 hours
	<u>AND</u>		
	B.5	Perform SR 3.2.2.1.	72 hours
	<u>AND</u>		
	B.6	Re-evaluate safety analyses and confirm results remain valid for duration of operation under these conditions.	5 days
C. Required Action and associated Completion Time of Condition B not met.	C.1	Be in MODE 2 with K_{eff} < 1.0.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. More than one rod not within alignment limit.	D.1.1	Verify SDM is within the limits specified in the COLR.	1 hour
	<u>OR</u>		
	D.1.2	Initiate boration to restore required SDM to within limit.	1 hour
	<u>AND</u>		
	D.2	Be in MODE 2 with $K_{eff} < 1.0$.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify individual rod positions within alignment limit.	12 hours
SR 3.1.4.2	-------------------NOTE-------------------- Only required to be performed if the rod position deviation monitor is inoperable. --- Verify individual rod positions within alignment limit.	Once within 4 hours and every 4 hours thereafter

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.4.3	Verify rod freedom of movement (trippability) by moving each rod not fully inserted in the core to a MRPI transition in either direction.	92 days
SR 3.1.4.4	Verify rod drop time of each rod, from the fully withdrawn position, is ≤ 1.8 seconds from the beginning of decay of stationary gripper coil voltage to dashpot entry, with: a. $T_{avg} \geq 500°F$; and b. Both reactor coolant pumps operating.	Once prior to reactor criticality after each removal of the reactor head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.5 Shutdown Bank Insertion Limit

LCO 3.1.5 The shutdown bank shall be at or above the insertion limit specified in the COLR.

---------------------------NOTE---------------------------
The shutdown bank may be outside the limit when required for performance of SR 3.1.4.3.

APPLICABILITY: MODE 1,
MODE 2 with $K_{eff} \geq 1.0$.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Shutdown bank not within limit.	A.1.1 Verify SDM is within the limits specified in the COLR. OR A.1.2 Initiate boration to restore SDM to within limit. AND A.2 Restore shutdown bank to within limit.	1 hour 1 hour 2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2 with $K_{eff} < 1.0$.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify the shutdown bank insertion is within the limit specified in the COLR.	12 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.6 Control Bank Insertion Limits

LCO 3.1.6 Control banks shall be within the insertion, sequence, and overlap limits specified in the COLR.

---NOTE---
The control bank being tested may be outside the limits when required for the performance of SR 3.1.4.3.

APPLICABILITY: MODE 1,
MODE 2 with $k_{eff} \geq 1.0$.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Control bank limits not met.	A.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	<u>OR</u>	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	
	A.2 Restore control bank(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2 with $K_{eff} < 1.0$.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify estimated critical control bank position is within the limits specified in the COLR.	Within 4 hours prior to achieving criticality
SR 3.1.6.2	Verify each control bank insertion is within the limits specified in the COLR.	12 hours
SR 3.1.6.3	-------------------NOTE------------------- Only required to be performed if the rod insertion limit monitor is inoperable. -- Verify each control bank insertion is within the limits specified in the COLR.	Once within 4 hours and every 4 hours thereafter
SR 3.1.6.4	Verify each control bank not fully withdrawn from the core is within the sequence and overlap limits specified in the COLR.	12 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Rod Position Indication

LCO 3.1.7 The Microprocessor Rod Position Indication (MRPI) System and the Demand Position Indication System shall be OPERABLE.

APPLICABILITY: MODE 1,
MODE 2 with $K_{eff} \geq 1.0$.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each inoperable MRPI per group and each demand position indicator per bank.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One MRPI per group inoperable for one or more groups.	A.1	Verify the position of the rods with inoperable position indicators by using movable incore detectors.	Once per 8 hours
	<u>OR</u>		
	A.2	Reduce THERMAL POWER to $\leq$ 50% RTP.	8 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One or more rods with inoperable position indicators have been moved > 24 steps in one direction since the last determination of the rod's position.	B.1	Verify the position of the rods with inoperable position indicators by using movable incore detectors.	4 hours
	<u>OR</u>		
	B.2	Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
C. One demand position indicator per bank inoperable for one or more banks.	C.1.1	Verify by administrative means all MRPIs for the affected banks are OPERABLE.	Once per 8 hours
	<u>AND</u>		
	C.1.2	Verify the most withdrawn rod and the least withdrawn rod of the affected banks are ≤ 12 steps from the OPERABLE demand position indicator for that bank.	Once per 8 hours
	<u>OR</u>		
	C.2	Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
D. Required Action and associated Completion Time of Condition A, Condition B or Condition C not met.	D.1	Be in MODE 2 with K_{eff} < 1.0.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. More than one MRPI per group inoperable for one or more groups. OR More than one demand position indicator per bank inoperable for one or more banks.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.1.7.1 Verify each MRPI agrees within 12 steps of the group demand position for the full indicated range of rod travel.	Prior to reactor criticality after each removal of the reactor head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.8 PHYSICS TESTS Exceptions—MODE 2

LCO 3.1.8 During the performance of PHYSICS TESTS, the requirements of

LCO 3.1.3, "Moderator Temperature Coefficient (MTC)";
LCO 3.1.4, "Rod Group Alignment Limits";
LCO 3.1.5, "Shutdown Bank Insertion Limit";
LCO 3.1.6, "Control Bank Insertion Limits";
LCO 3.4.2, "RCS Minimum Temperature for Criticality"

may be suspended, provided:

a. THERMAL POWER is maintained ≤ 5% RTP;

b. RCS lowest loop average temperature is ≥ 530°F; and

c. SDM is within the limits specified in the COLR.

APPLICABILITY: During PHYSICS TESTS.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. SDM not within limit.	A.1	Initiate boration to restore SDM to within limit.	15 minutes
	<u>AND</u>		
	A.2	Suspend PHYSICS TESTS exceptions.	1 hour
B. THERMAL POWER not within limit.	B.1	Open reactor trip breakers.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. RCS lowest loop average temperature not within limit.	C.1	Restore RCS lowest loop average temperature to within limit.	15 minutes
D. Required Action and associated Completion Time of Condition C not met.	D.1	Be in MODE 3.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.8.1	Perform a COT on power range and intermediate range channels per SR 3.3.1.7 and SR 3.3.1.8.	Once within 7 days prior to criticality
SR 3.1.8.2	Verify the RCS lowest loop average temperature is ≥ 530°F.	30 minutes
SR 3.1.8.3	Verify THERMAL POWER is ≤ 5% RTP.	30 minutes
SR 3.1.8.4	Verify SDM is within the limits specified in the COLR.	24 hours

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

According to Atomic Industrial Forum (AIF) GDC 27 and 28 (Ref. 1), two independent reactivity control systems must be available and capable of holding the reactor core subcritical from any hot standby or hot operating condition. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel.

SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs) which are defined as Condition 2 events in Reference 2 (i.e., events which can be expected to occur during a calendar year with moderate frequency). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion or scram of all shutdown and control rods, assuming that the single rod cluster assembly of highest reactivity worth is fully withdrawn and the fuel and moderator temperature are changed to the nominal hot zero power temperature.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are provided by the use of movable rod cluster control assemblies (RCCAs) and soluble boric acid in the Reactor Coolant System (RCS) which each provide a neutron absorbing mechanism. The Control Rod System can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the Control Rod System, together with the boration system, provides the SDM during power operation and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the rod of highest reactivity worth remains fully withdrawn. The chemical and volume control system can control the soluble boron concentration to compensate for fuel depletion during operation and all xenon burnout reactivity changes and maintain the reactor subcritical under cold conditions.

(continued)

BASES

BACKGROUND (continued)

During power operation, SDM control is ensured by operating with the shutdown bank fully withdrawn and the control banks within the limits of LCO 3.1.6, "Control Bank Insertion Limits." The shutdown bank fully withdrawn position is defined in the COLR. When the plant is in the shutdown and refueling modes, the SDM requirements are met by means of adjustments to the RCS boron concentration.

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in the safety analyses. The safety analysis (Ref. 3) establishes a SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with the assumption of the highest worth rod stuck out following a scram.

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are not exceeded. This is done by ensuring that:

a. The reactor can be made subcritical from all operating conditions, transients, and Design Basis Accidents;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (departure from nucleate boiling ratio (DNBR), fuel centerline temperature limits for AOOs, and ≤ 200 cal/gm energy deposition for the rod ejection accident); and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The most limiting accident for the SDM requirements is based on a steam line break (SLB), as described in the accident analysis (Ref. 3). The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected steam generator (SG), and consequently the RCS. This results in a reduction of the reactor coolant temperature. The resultant coolant shrinkage causes a reduction in pressure. In the presence of a negative moderator temperature coefficient, this cooldown causes an increase in core reactivity. The most limiting SLB for both one loop and two loop operation, with respect to potential fuel damage before a reactor trip occurs, is a guillotine break of a main steam line inside containment initiated at the end of core life. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the SLB, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power, and THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1.

In addition to the limiting SLB transient, the SDM requirement must also protect against:

a. Inadvertent boron dilution;

b. An uncontrolled rod withdrawal from subcritical or low power condition;

c. Startup of an inactive reactor coolant pump (RCP); and

d. Rod ejection.

Each of these events is discussed below.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In the boron dilution analysis (Ref. 4), the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS and the assumed dilution flow rate, directly affect the results of the analysis (i.e., the time available to operators to stop the dilution event). This event is analyzed for refueling, shutdown (MODE 5) and power operation conditions and is most limiting at the beginning of core life, when critical boron concentrations are highest.

Depending on the system initial conditions and reactivity insertion rate, the uncontrolled rod withdrawal transient is terminated by either a high power level trip or a high pressurizer pressure trip (Ref. 5). In all cases, power level, RCS pressure, linear heat rate, and the DNBR do not exceed allowable limits if SDM has been maintained.

The startup of an inactive RCP will not result in a "cold water" criticality, even if the maximum difference in temperature exists between the SG and the core (Ref. 6). The maximum positive reactivity addition that can occur due to an inadvertent RCP start is less severe than the effects of a small steam line break with one loop operation. Startup of an idle RCP cannot, therefore, produce a return to power from the hot standby condition if SDM has been maintained.

The ejection of a control rod constitutes a break in the RCS which rapidly adds reactivity to the reactor core, causing both the core power level and heat flux to increase with corresponding increases in reactor coolant temperatures and pressure (Ref. 7). The ejection of a rod also produces a time dependent redistribution of core power which results in a high neutron flux trip. Fuel and cladding limits are not exceeded if SDM has been maintained.

SDM satisfies Criterion 2 of the NRC Policy Statement. Even though it is not directly observed from the control room, SDM is considered an initial condition process variable because it is periodically monitored to ensure that the plant is operating within the bounds of accident analysis assumptions.

(continued)

BASES (continued)

LCO

SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration in the RCS.

The COLR provides the shutdown margin requirement with respect to RCS boron concentration. The SLB (Ref. 3) and the boron dilution (Ref. 4) accidents are the most limiting analyses that establish the SDM curve in the COLR. The maximum shutdown margin requirement occurs at end of cycle life and is based on the value used in analysis for the SLB. Early in cycle life, less SDM is required and is bounded by the requirements provided in the COLR. All other accidents analyses are based on 1% reactivity shutdown margin. For SLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed 10 CFR 100, "Reactor Site Criteria," limits (Ref. 8). For the boron dilution accident, if the LCO is violated, the minimum required time assumed for operator action to terminate dilution may no longer be applicable.

APPLICABILITY

In MODE 2 with $k_{eff} < 1.0$ and in MODES 3, 4 and 5, the SDM requirements are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analyses discussed above. In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration." In MODE 1 and MODE 2 with $K_{eff} \geq 1.0$, SDM is ensured by complying with LCO 3.1.5, "Shutdown Bank Insertion Limit," and LCO 3.1.6, "Control Bank Insertion Limits."

(continued)

BASES (continued)

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that boration will be continued until the SDM requirements are met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the flowpath of choice would utilize a highly concentrated solution, such as that normally found in the boric acid storage tank, or the refueling water storage tank. The operator should borate with the best source available for the plant conditions.

In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of cycle when the boron concentration may approach or exceed 2000 ppm. Assuming that a value of 1% $\Delta k/k$ must be recovered and a boration flow rate of 10 gpm using 13,000 ppm boric acid solution, it is possible to increase the boron concentration of the RCS by 100 ppm in approximately 35 minutes. If a boron worth of 10 pcm/ppm is assumed, this combination of parameters will increase the SDM by 1% $\Delta k/k$. These boration parameters of 10 gpm and 13,000 ppm represent typical values and are provided for the purpose of offering a specific example.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODE 2 with K_{eff} < 1.0 and MODES 3, 4, and 5, the SDM is verified by comparing the RCS boron concentration to a SHUTDOWN MARGIN requirement curve that was generated by taking into account estimated RCS boron concentrations, core power defect, control bank position, RCS average temperature, fuel burnup based on gross thermal energy generation, xenon concentration, samarium concentration, and isothermal temperature coefficient (ITC).

The Frequency of 24 hours is based on the generally slow change in required boron concentration and the low probability of an accident occurring without the required SDM. This allows time for the operator to collect the required data, which includes performing a boron concentration analysis, and complete the calculation.

REFERENCES

1. Atomic Industrial Forum (AIF) GDC 27 and 28, Issued for comment July 10, 1967.
2. "American National Standard Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," N18.2-1973.
3. UFSAR, Section 15.1.5.
4. UFSAR, Section 15.4.4.
5. UFSAR, Section 15.4.2.
6. UFSAR, Section 15.4.3.
7. UFSAR, Section 15.4.5.
8. 10 CFR 100.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Core Reactivity

BASES

BACKGROUND

According to Atomic Industrial Forum (AIF) GDC 27, 28, 29, and 30 (Ref. 1), reactivity shall be controllable, such that subcriticality is maintained under cold conditions, and acceptable fuel design limits are not exceeded during normal operation and anticipated operational occurrences. Therefore, reactivity balance is used as a measure of the predicted versus measured core reactivity during power operation. The periodic confirmation of core reactivity is necessary to ensure that Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, control rod worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SHUTDOWN MARGIN (SDM) or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, "SHUTDOWN MARGIN (SDM))" in ensuring the reactor can be brought safely to cold, subcritical conditions.

(continued)

BASES

BACKGROUND (continued)

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers producing zero net reactivity. Excess reactivity can be inferred from the boron letdown curve (or critical boron curve) in the core design report, which provides an indication of the soluble boron concentration in the Reactor Coolant System (RCS) versus cycle burnup. Periodic measurement of the RCS boron concentration for comparison with the predicted value with other variables fixed or stable (such as rod height, temperature, pressure, and power), provides a convenient method of ensuring that core reactivity is within design expectations and that the calculational models used to generate the safety analysis are adequate.

In order to achieve the required fuel cycle energy output, the uranium enrichment, in the new fuel loading and in the fuel remaining from the previous cycle, provides excess positive reactivity beyond that required to sustain steady state operation throughout the cycle. When the reactor is critical at RTP and normal operating temperature, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, whatever neutron poisons (mainly xenon and samarium) are present in the fuel, and the RCS boron concentration.

When the core is producing THERMAL POWER, the fuel is being depleted and excess reactivity is decreasing. As the fuel depletes, the RCS boron concentration is reduced to decrease negative reactivity and maintain constant moderator temperature. The boron letdown curve is based on steady state operation at RTP. Therefore, deviations from the predicted boron letdown curve may indicate deficiencies in the design analysis, deficiencies in the calculational models, or abnormal core conditions, and must be evaluated.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The acceptance criteria for core reactivity are that the reactivity balance limit ensures plant operation is maintained within the assumptions of the safety analyses.

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations. Every accident evaluation (Ref. 2) is, therefore, dependent upon accurate evaluation of core reactivity. In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod ejection accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity balance additionally ensures that the Nuclear Design Methodology provides an accurate representation of the core reactivity.

Design calculations and safety analyses are performed for each fuel cycle for the purpose of predetermining reactivity behavior and the RCS boron concentration requirements for reactivity control during fuel depletion.

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted RCS boron concentrations for identical core conditions at beginning of cycle life (BOL) do not agree, then the assumptions used in the reload cycle design analysis or the calculational models used to predict soluble boron requirements may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOL, then the prediction may be normalized to the measured boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown curve that develop during fuel depletion may be an indication that the calculational model is not adequate for core burnups beyond BOL, or that an unexpected change in core conditions has occurred.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RTP following startup from a refueling outage, with the control rods in their normal positions for power operation. The normalization is performed at BOL conditions, so that core reactivity relative to predicted values can be continually monitored and evaluated as core conditions change during the cycle.

Core reactivity satisfies Criterion 2 of the NRC Policy Statement.

LCO

Long term core reactivity behavior is a result of the core physics design and cannot be easily controlled once the core design is fixed. During operation, therefore, the LCO can only be ensured through measurement and tracking, and appropriate actions taken as necessary. Large differences between actual and predicted core reactivity may indicate that the assumptions of the DBA and transient analyses are no longer valid, or that the uncertainties in the Nuclear Design Methodology are larger than expected. A limit on the reactivity balance of ± 1% $\Delta k/k$ has been established based on engineering judgment. A 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

When measured core reactivity is within 1% $\Delta k/k$ of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits. Since deviations from the limit are normally detected by comparing predicted and measured steady state RCS critical boron concentrations, the difference between measured and predicted values would be approximately 100 ppm (depending on the boron worth) before the limit is reached. These values are well within the uncertainty limits for analysis of boron concentration samples, so that spurious violations of the limit due to uncertainty in measuring the RCS boron concentration are unlikely.

(continued)

BASES (continued)

APPLICABILITY

The limits on core reactivity must be maintained during MODE 1 and MODE 2 with $K_{eff} \geq 1.0$ because a reactivity balance must exist when the reactor is critical or producing THERMAL POWER. As the fuel depletes, core conditions are changing, and confirmation of the reactivity balance ensures the core is operating as designed. This Specification does not apply in MODE 2 with $K_{eff} < 1.0$ or MODES 3, 4, and 5 because the reactor is shut down and the reactivity balance is only changing because of xenon.

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Boron Concentration") ensure that fuel movements are performed within the bounds of the safety analysis. An SDM demonstration is required during the first startup following operations that could have altered core reactivity (SR 3.1.2.1).

ACTIONS

A.1 and A.2

Should an anomaly develop between measured and predicted core reactivity, an evaluation of the core design and safety analysis must be performed. Core conditions are evaluated to determine their consistency with input to design calculations. Measured core and process parameters are evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models are reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 72 hours is based on the low probability of a DBA occurring during this period, and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Following evaluations of the core design and safety analysis, the cause of the reactivity anomaly may be resolved. If the cause of the reactivity anomaly is a mismatch in core conditions at the time of RCS boron concentration sampling, then a recalculation of the RCS boron concentration requirements may be performed to demonstrate that core reactivity is behaving as expected. If an unexpected physical change in the condition of the core has occurred, it must be evaluated and corrected, if possible. If the cause of the reactivity anomaly is in the calculation technique, then the calculational models must be revised to provide more accurate predictions. If any of these results are demonstrated, and it is concluded that the reactor core is acceptable for continued operation, then the boron letdown curve may be renormalized and power operation may continue. If operational restriction or additional SRs are necessary to ensure the reactor core is acceptable for continued operation, then they must be defined.

The required Completion Time of 72 hours is adequate for preparing whatever operating restrictions or Surveillances that may be required to allow continued reactor operation.

B.1

If the core reactivity cannot be restored to within the 1% $\Delta k/k$ limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 with $K_{eff} < 1.0$ within 6 hours. If the SDM for MODE 2 with $K_{eff} < 1.0$ is not met, then the boration required by SR 3.1.1.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 2 with $K_{eff} < 1.0$ from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity must be verified following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling). The comparison must be made prior to entering MODE 1 when the core conditions such as control rod position, moderator temperature, and samarium concentration are fixed or stable. Since the reactor must be critical to verify core reactivity, it is acceptable to enter MODE 2 with Keff ≥ 1.0 to perform this SR. This SR is modified by a Note to clarify that the SR does not need to be performed until prior to entering MODE 1.

SR 3.1.2.2

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made, considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Frequency of 31 EFPD, is acceptable, based on the slow rate of core changes due to fuel depletion and the presence of other indicators (QPTR, AFD, etc.) for prompt indication of an anomaly. The SR is modified by two Notes. The first Note states that the SR is only required after 60 effective full power days (EFPD). The second Note indicates that the normalization of predicted core reactivity to the measured value must take place within the first 60 EFPD after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations.

REFERENCES

1. Atomic Industrial Forum (AIF) GDC 27, 28, 29, and 30, Issued for comment July 10, 1967.

2. UFSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to Atomic Industrial Forum (AIF) GDC 8 (Ref. 1), the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). MTC is defined as the change in reactivity per degree change in moderator temperature since temperature is directly proportional to coolant density. The reactor is designed to operate with a negative MTC over the largest possible range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Both initial and reload cores are designed so that the beginning of cycle life (BOL) MTC is less than zero when THERMAL POWER is at RTP. The actual value of the MTC is dependent on core characteristics, such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed distributed poisons to yield an MTC at BOL within the range analyzed in the plant accident analysis. The end of cycle life (EOL) MTC is also limited by the requirements of the accident analysis. Fuel cycles that are designed to achieve high burnups or that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the EOL limit.

(continued)

BASES

BACKGROUND (continued)

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting conditions assumed in the UFSAR accident and transient analyses.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified MTC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2); and

b. The MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

The UFSAR, Chapter 15 (Ref. 2), contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the most positive value and most negative value of the MTC are important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions to ensure that the accident results are bounding (Ref. 3).

The consequences of accidents that cause core overheating must be evaluated when the MTC is positive (i.e., upper limit). Such accidents include the rod withdrawal transient from either zero or RTP, loss of main feedwater flow, and loss of forced reactor coolant flow. The consequences of accidents that cause core overcooling must be evaluated when the MTC is negative (i.e., lower limit). Such accidents include sudden feedwater flow increase and sudden decrease in feedwater temperature.

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is at BOL or EOL. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

MTC satisfies Criterion 2 of the NRC Policy Statement. Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the MTC to be within the specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the original accident analysis during operation.

Assumptions made in safety analyses require that the MTC be less positive than a given upper bound and more positive than a given lower bound. The MTC is most positive at BOL; this upper bound must not be exceeded. This maximum upper limit occurs at BOL, all rods out (ARO), hot zero power (HZP) conditions. At EOL the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The Surveillance check at BOL on MTC provides confirmation that the MTC is behaving as anticipated and will be within limits at 70% RTP, full power, and EOL so that the acceptance criteria are met.

The LCO establishes a maximum positive value that cannot be exceeded. The BOL positive limit and the EOL negative limit are established in the COLR to allow specifying limits for each particular cycle. This permits the plant to take advantage of improved fuel management and changes in plant operating schedule.

If the LCO limits are not met, the plant response during transients may not be as predicted. The core could violate criteria that prohibit a return to criticality, or the departure from nucleate boiling ratio criteria of the approved correlation may be violated, which could lead to a loss of the fuel cladding integrity.

(continued)

BASES (continued)

APPLICABILITY

In MODE 1, the upper and lower limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled CONTROL ROD assembly or group withdrawal) will not violate the assumptions of the accident analysis. The lower MTC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents will not violate the assumptions of the accident analysis since MTC becomes more negative as the cycle burnup increases because the RCS boron concentration is reduced. In MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents using the MTC as an analysis assumption are initiated from these MODES.

ACTIONS

A.1

MTC must be kept within the upper limit specified in LCO 3.1.3 to ensure that assumptions made in the safety analysis remain valid. The upper limit of Condition A is the upper limit specified in the COLR since this value will always be less than or equal to the maximum upper limit specified in the LCO.

If the upper MTC limit is violated at BOL, administrative withdrawal limits for control banks must be established to maintain the MTC within its limits in the future. A Completion Time of 24 hours provides enough time for evaluating the MTC measurement and computing the required bank withdrawal limits.

As cycle burnup is increased, the RCS boron concentration will be reduced. The reduced boron concentration causes the MTC to become more negative. Using physics calculations, the time in cycle life at which the calculated MTC will meet the LCO requirement can be determined. At this point in core life Condition A no longer exists. The plant is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

(continued)

BASES

ACTIONS (continued)

B.1

If the required administrative withdrawal limits at BOL are not established within 24 hours, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status the plant must be brought to MODE 2 with k_{eff} < 1.0. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

C.1

Exceeding the EOL MTC lower limit means that the safety analysis assumptions of the EOL accidents that use a bounding negative MTC value may be invalid. If it is determined during physics testing that the EOL MTC value will exceed the most negative MTC limit specified in the COLR, the safety analysis and core design must be re-evaluated prior to reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm to ensure that operation near the EOL remains acceptable. The 300 ppm limit is sufficient to prevent EOL operation at or below the accident analysis MTC assumptions.

Condition C has been modified by a Note that requires that Required Action C.1 must be completed whenever this Condition is entered. This is necessary to ensure that the plant does not operate at conditions where the MTC would be below the most negative limit specified in the COLR.

Required Action C.1 is modified by a Note which states that LCO 3.0.4 is not applicable. This Note is provided since the requirement to re-evaluate the core design and safety analysis prior to reaching an equivalent RTP ARO boron concentration of 300 ppm is adequate action without restricting entry into MODE 1.

(continued)

BASES

ACTIONS (continued)

D.1

If the re-evaluation of the accident analysis cannot support the predicted EOL MTC lower limit, or if the Required Actions of Condition C are not completed within the associated Completion Time the plant must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the plant must be brought to MODE 4 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

This SR requires measurement of the MTC at BOL prior to entering MODE 1 in order to demonstrate compliance with the most positive MTC LCO. Meeting the limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels.

The BOL MTC value for ARO will be inferred from isothermal temperature coefficient (ITC) measurements obtained during the physics tests after refueling. The ARO value can be directly compared to the BOL MTC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

The measurement of the MTC at the beginning of the fuel cycle is adequate to confirm that the MTC remains within its upper limits and will be within limits at 70% RTP, full power and at EOL, since this coefficient changes slowly, due principally to the reduction in RCS boron concentration associated with fuel burnup. This measurement is consistent with the recommendations detailed in Reference 4.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.3.2

This SR requires measurement of MTC at BOL prior to entering MODE 1 after each refueling in order to demonstrate compliance with the 70% RTP MTC limit. The Frequency of "once prior to entering MODE 1 after each refueling" ensures the limit will also be met at higher power levels.

SR 3.1.3.3

This SR requires measurement of MTC at BOL prior to entering MODE 1 after each refueling in order to demonstrate compliance with the most negative MTC LCO. Meeting this limit prior to entering MODE 1 ensures that the limit will also be met at EOL.

The MTC value for EOL is also inferred from the ITC measurements. The EOL value is calculated using the predicted EOL MTC from the core design report and the difference between the measured and predicted ITC. The EOL value is directly compared to the most negative EOL value established in the COLR to ensure that the predicted EOL negative MTC value is within the accident analysis assumptions.

REFERENCES

1. Atomic Industrial Forum (AIF) GDC 8, Issued for comment July 10, 1967.

2. UFSAR, Chapter 15.

3. WCAP 9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

4. Letter from J. P. Durr (NRC) to B. A. Snow (RGE), Subject: "Inspection Report No. 50-244/88-06", dated April 28, 1988.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Rod Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY (e.g., trippability) of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SHUTDOWN MARGIN (SDM). The applicable criteria for these reactivity and power distribution design requirements are Atomic Industrial Forum (AIF) GDC 6, 14, 27 and 28 (Ref. 1), and 10 CFR 50.46 (Ref. 2).

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM. Limits on control rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are movable neutron absorbing devices which are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms (CRDMs). Each CRDM moves its RCCA one step (approximately ⅝ inch) at a time, but at varying rates (steps per minute) depending on the signal output from the Rod Control System.

(continued)

BASES

BACKGROUND (continued)

The RCCAs are divided among control banks and a shutdown bank. Control banks are used to compensate for changes in reactivity due to variations in operating conditions of the reactor such as coolant temperature, power level, boron or xenon concentration. The shutdown bank provides additional shutdown reactivity such that the total shutdown worth of the bank is adequate to provide shutdown for all operating and hot zero power conditions with the single RCCA of highest reactivity worth fully withdrawn. Each bank is further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and one shutdown bank at Ginna Station.

The shutdown bank is maintained either in the fully inserted or fully withdrawn position. The fully withdrawn position is defined in the COLR. The control banks are moved in an overlap pattern, using the following withdrawal sequence: When control bank A reaches a predetermined height in the core, control bank B begins to move out with control bank A. Control bank A stops at the fully withdrawn position, and control bank B continues to move out. When control bank B reaches a predetermined height, control bank C begins to move out with control bank B. This sequence continues until control banks A, B, and C are at the fully withdrawn position, and control bank D is near the fully withdrawn position at RTP. The insertion sequence is the opposite of the withdrawal sequence (i.e., bank D is inserted first) but follows the same overlap pattern. The control rods are arranged in a radially symmetric pattern, so that control bank motion does not introduce radial asymmetries in the core power distributions.

The axial position of shutdown rods and control rods is indicated by two separate and independent systems: the Bank Demand Position Indication System (commonly called group step counters) and the Microprocessor Rod Position Indication (MRPI) System.

(continued)

BASES

BACKGROUND (continued)

The Bank Demand Position Indication System counts the pulses from the rod control system that moves the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± ⅝ inch), but if a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The MRPI System also provides a highly accurate indication of actual control rod position, but at a lower precision than the step counters. The MRPI system consists of one digital detector assembly per rod. All the detector assemblies consist of one coil stack which is multiplexed and becomes input to two redundant MRPI signal processors. Each signal processor independently monitors all rods and senses a rod bottom for any rod. The MRPI system directly senses rod position in intervals of 12 steps for each rod. The digital detector assemblies consist of 20 discrete coil pairs spaced at 12-step intervals. The true rod position is always within $\pm$ 8 steps of the indicated position ($\pm$ 6 steps due to the 12-step interval and $\pm$ 2 steps transition uncertainty due to processing and coil sensitivity). With an indicated deviation of 12 steps between the group step counter and MRPI, the maximum deviation between actual rod position and the demand position would be 20 steps, or 12.5 inches.

The safety concerns associated with the MRPI system are associated with generation of a rod drop/rod stop signal which blocks auto rod withdrawal and the ability to comply with the rod misalignment requirement. A rod bottom signal from both signal processors is required to generate a rod drop/rod stop signal. The two-out-of-two coincident signal requirement reduces inadvertent rod drop/rod stop but does not affect the accident analysis assumptions.

(continued)

BASES

BACKGROUND (continued)

The bank demand position and the MRPI rod position signals are monitored by a rod deviation monitoring system that provides an alarm whenever the individual rod position signal deviates from the bank demand signal by > 12 steps. The rod deviation alarm will be generated by the Plant Process Computer System (PPCS).

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (Ref. 3). The acceptance criteria for addressing control rod inoperability or misalignment are that:

a. There be no violations of:

    1. Specified acceptable fuel design limits, or

    2. Reactor Coolant System (RCS) pressure boundary integrity; and

b. The core remains subcritical after accident transients.

Two types of misalignment are distinguished. During movement of a control rod group, one rod may stop moving, while the other rods in the group continue (i.e., static rod misalignment). This condition may cause excessive power peaking. The second type of misalignment occurs if one rod fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the remaining control rods to meet the SDM requirement, with the maximum worth rod stuck fully withdrawn.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Three types of analysis are performed in regard to static rod misalignment (Ref. 4). The first type of analysis considers the case where any one rod is completely inserted into the core with all other rods completely withdrawn. With control banks at their insertion limits, the second type of analysis considers the case when any one rod is completely inserted into the core. The third type of analysis considers the case of a completely withdrawn single rod from a bank inserted to its insertion limit. Satisfying limits on departure from nucleate boiling ratio in all three of these cases bounds the situation when a rod is misaligned from its group by 12 steps.

The second type of misalignment occurs if one RCCA fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition is assumed in the evaluation to determine that the required SDM is met with the maximum worth RCCA fully withdrawn following a main steam line break (Ref. 5).

The Required Actions in this LCO ensure that either deviations from the alignment limits will be corrected or that THERMAL POWER will be adjusted so that excessive local linear heat rates (LHRs) will not occur, and that the requirements on SDM and ejected rod worth are preserved.

Continued operation of the reactor with a misaligned control rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy hot channel factor ($F^N_{\Delta H}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned, the assumptions that are used to determine the rod insertion limits, AFD limits, and quadrant power tilt limits are not preserved. Therefore, the limits may not preserve the design peaking factors, and $F_Q(Z)$ and $F^N_{\Delta H}$ must be verified directly by incore mapping. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(Z)$ and $F^N_{\Delta H}$ to the operating limits.

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

All shutdown and control rods must be OPERABLE to provide the negative reactivity necessary to provide adequate shutdown for all operating and hot zero power conditions. Shutdown and control rod OPERABILITY is defined as being trippable such that the necessary negative reactivity assumed in the accident analysis is available. If a control rod(s) is discovered to be immovable but remains trippable and aligned, the control rod is considered to be OPERABLE.

The limits on shutdown or control rod alignments ensure that the assumptions in the safety analysis will remain valid. The requirements on OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The OPERABILITY requirements also ensure that the RCCAs and banks maintain the correct power distribution and rod alignment.

The requirement to maintain the rod alignment of each individual rod position as indicated by MRPI to within plus or minus 12 steps of their group step counter demand position is conservative. The minimum misalignment assumed in safety analysis with respect to power distribution and SDM is 25 steps, while a total misalignment from fully withdrawn to fully inserted is assumed for the control rod misalignment accident.

The rod position deviation monitor is used to verify rod alignment on a continuous basis and will provide an alarm whenever the individual rod position signal deviates from the bank demand signal by > 12 steps. Verification that the rod positions are within the alignment limit is made every 12 hours (SR 3.1.4.1). When the rod position deviation monitor is inoperable a verification that the rod positions are within limit must be made more frequently (SR 3.1.4.2).

Failure to meet the requirements of this LCO may produce unacceptable power peaking factors and LHRs, or unacceptable SDMs, all of which may constitute initial conditions inconsistent with the safety analysis.

(continued)

BASES (continued)

APPLICABILITY

The requirements on RCCA OPERABILITY and alignment are applicable in MODE 1 and MODE 2 with $K_{eff} \geq 1.0$ because these are the only MODES in which neutron (or fission) power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODE 2 with $K_{eff} < 1.0$ and MODES 3, 4, 5, and 6, the alignment limits do not apply because the reactor is shut down and not producing fission power. In the shutdown MODES, the OPERABILITY of the shutdown and control rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. See LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," for SDM in MODE 2 with $K_{eff} < 1.0$ and MODES 3, 4, and 5 and LCO 3.9.1, "Boron Concentration," for boron concentration requirements during MODE 6.

ACTIONS

A.1.1 and A.1.2

When one or more rods are untrippable, there is a possibility that the required SDM may be adversely affected. Under these conditions, it is important to determine the SDM, and if it is less than the required value, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate for determining SDM and, if necessary, for initiating emergency boration to restore SDM. Boration is assumed to continue until the required SDM is restored.

In this situation, SDM verification must include the worth of the untrippable rod, as well as a remaining rod of maximum worth.

A.2

If the untrippable rod(s) cannot be restored to OPERABLE status, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the plant must be brought to at least MODE 2 with $K_{eff} < 1.0$ within 6 hours.

(continued)

BASES

ACTIONS

A.2 (continued)

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 2 with $K_{eff} < 1.0$ from full power conditions in an orderly manner and without challenging plant systems.

B.1.1 and B.1.2

When a rod is misaligned, it can usually be moved and is still trippable. If the rod cannot be realigned within 1 hour, then SDM must be verified to be within the limits specified in the COLR or boration must be initiated to restore the SDM. The Completion Time of 1 hour gives the operator sufficient time to perform either action in an orderly manner.

B.2, B.3, B.4, B.5, and B.6

For continued operation with a misaligned rod, reactor power must be reduced, SDM must periodically be verified within limits, hot channel factors ($F_Q(Z)$ and $F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible.

Reduction of power to ≤ 75% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded (Ref. 6). The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

(continued)

BASES

ACTIONS

B.2, B.3, B.4, B.5, and B.6 (continued)

Verifying that $F_Q(Z)$ and $F^N_{\Delta H}$ are within the required limits (i.e., SR 3.2.1.1 and SR 3.2.2.1) ensures that current operation at ≤ 75% RTP with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain flux maps of the core power distribution using the incore flux mapping system and to calculate $F_Q(Z)$ and $F^N_{\Delta H}$.

Once current conditions have been verified acceptable, time is available to perform evaluations of accident analysis to determine that core limits will not be exceeded during a Design Basis Accident for the duration of operation under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

C.1

When Required Actions of Condition B cannot be completed within their Completion Time, the plant must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the plant must be brought to at least MODE 2 with $K_{eff} < 1.0$ within 6 hours, which obviates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 2 with $K_{eff} < 1.0$ from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

D.1.1 and D.1.2

More than one control rod becoming misaligned from its group position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. One hour allows the operator adequate time to determine SDM. Restoration of the required SDM, if necessary, requires increasing the RCS boron concentration to provide negative reactivity, as described in the Bases of LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and start the boric acid pumps. Boration is assumed to continue until the required SDM is restored.

D.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement, the plant conditions fall outside of the accident analysis assumptions. Since automatic bank sequencing would continue to cause misalignment, the plant must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the plant must be brought to at least MODE 2 with $K_{eff} < 1.0$ within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 2 with $K_{eff} < 1.0$ from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual rod positions are within alignment limits using MRPI or the PPCS at a Frequency of 12 hours provides a history that allows the operator to detect a rod that is beginning to deviate from its expected position. This Frequency takes into account other rod position information that is continuously available to the operator in the control room, so that during actual rod motion, deviations can immediately be detected.

SR 3.1.4.2

When the rod position deviation monitor (i.e., the PPCS) is inoperable, no control room alarm is available between the normal 12 hour Frequency to alert the operators of a rod misalignment. A reduction of the Frequency to 4 hours provides sufficient monitoring of the rod positions when the monitor is inoperable. This Frequency takes into account other rod position information that is continuously available to the operator in the control room, so that during actual rod motion, deviations can immediately be detected.

This SR is modified by a Note that states that performance of this SR is only necessary when the rod position deviation monitor is inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.3

Verifying each control rod is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2 with $K_{eff} \geq 1.0$, tripping each control rod would result in radial or axial power tilts, or oscillations. Exercising each individual control rod every 92 days provides increased confidence that all rods continue to be OPERABLE without exceeding the alignment limit, even if they are not regularly tripped. Moving each control rod to a MRPI transition will not cause radial or axial power tilts, or oscillations, to occur. The 92 day Frequency takes into consideration other information available to the operator in the control room and SR 3.1.4.1, which is performed more frequently and adds to the determination of OPERABILITY of the rods. During or between required performances of SR 3.1.4.3 (determination of control rod OPERABILITY by movement), if a control rod(s) is discovered to be immovable, but remains trippable and aligned, the control rod(s) is considered to be OPERABLE. At any time, if a control rod(s) is immovable, a determination of the trippability (OPERABILITY) of the control rod(s) must be made, and appropriate action taken.

SR 3.1.4.4

Verification of rod drop times allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. Measuring rod drop times prior to reactor criticality, after reactor vessel head removal, ensures that the reactor internals and rod drive mechanism will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect control rod motion or drop time. This testing is performed with both RCPs operating and the average moderator temperature $\geq$ 500°F to simulate a reactor trip under actual conditions.

This Surveillance is performed during a plant outage, due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance were performed with the reactor at power.

(continued)

BASES (continued)

REFERENCES

1. Atomic Industrial Forum (AIF) GDC 6, 14, 27, and 28, Issued for comment July 10, 1967.
2. 10 CFR 50.46.
3. UFSAR, Chapter 15.
4. UFSAR, Section 15.4.6.
5. UFSAR, Section 15.1.5.
6. UFSAR, Section 15.4.2.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Shutdown Bank Insertion Limit

BASES

BACKGROUND

The insertion limits of the shutdown and control rods define the deepest insertion into the core with respect to core power which is allowed and are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available ejected rod worth, SHUTDOWN MARGIN (SDM), and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are Atomic Industrial Forum (AIF) GDC 27, 28, 29, and 32 (Ref. 1), and 10 CFR 50.46 (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and a shutdown bank. Each bank is further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and one shutdown bank at Ginna Station. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The shutdown bank insertion limit is defined in the COLR. The shutdown bank is required to be at or above the insertion limit lines.

(continued)

BASES

BACKGROUND (continued)

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally automatically controlled by the Rod Control System, but they can also be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating or diluting). The control banks must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power operations. Hence, they are not capable of adding a large amount of positive reactivity. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity change associated with large changes in RCS temperature.

The design calculations are performed with the assumption that the shutdown bank is withdrawn first. The shutdown bank can be fully withdrawn without the core going critical. The fully withdrawn position is defined in the COLR. This provides available negative reactivity in the event of boration errors. The shutdown bank is controlled manually by the control room operator. The shutdown bank is either fully withdrawn or fully inserted. The shutdown bank must be completely withdrawn from the core, prior to withdrawing any control banks during an approach to criticality. The shutdown bank is then left in this position until the reactor is shut down. The shutdown bank affects core power and burnup distribution, and adds negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.4, "Rod Group Alignment Limits," LCO 3.1.5, "Shutdown Bank Insertion Limit," LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

(continued)

BASES

BACKGROUND (continued)

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the shutdown and control bank insertion limits restrict the reactivity that could be added in the event of a rod ejection accident, and ensure the required SDM is maintained.

Operation within the subject LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Trip System (RTS) trip function.

APPLICABLE SAFETY ANALYSES

On a reactor trip, all RCCAs (shutdown bank and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown bank shall be at or above the insertion limit and available to insert the maximum amount of negative reactivity on a reactor trip signal. The control banks may be partially inserted in the core, as allowed by LCO 3.1.6, "Control Bank Insertion Limits." The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") following a reactor trip from full power. The combination of control banks and the shutdown bank (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power, and to maintain the required SDM at rated no load temperature (Ref. 3). The shutdown bank insertion limit also limits the reactivity worth of an ejected shutdown rod.

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment is that:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. There be no violations of:

1. Specified acceptable fuel design limits, or

2. RCS pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown bank insertion limit affects safety analysis involving core reactivity and SDM (Ref. 3).

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes the maximum worth RCCA remains fully withdrawn upon trip (Refs. 4, 5, 6, and 7).

Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worths.

The control and shutdown bank insertion limits, together with AFD, QPTR and the control and shutdown bank alignment limits, ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Refs. 4, 5, 6, and 7).

The shutdown bank insertion limit preserves an initial condition assumed in the safety analyses and, as such, satisfies Criterion 2 of the NRC Policy Statement.

LCO

The shutdown bank must be at or above the insertion limit any time the reactor is critical and prior to withdrawal of any control rod. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

(continued)

BASES

LCO (continued)

The LCO is modified by a Note indicating the LCO requirement is suspended during SR 3.1.4.3. This SR verifies the freedom of the rods to move, and requires the shutdown bank to move below the LCO limits, which would normally violate the LCO.

The shutdown bank insertion limit is defined in the COLR.

APPLICABILITY

The shutdown bank must be within the insertion limit, with the reactor in MODE 1 and MODE 2 with $K_{eff} \geq 1.0$. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. In MODE 2 with $K_{eff} < 1.0$ and MODE 3, 4, 5, or 6, the shutdown bank insertion limit does not apply because the reactor is shutdown and not producing fission power. In shutdown MODES the OPERABILITY of the shutdown rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. Refer to LCO 3.1.1 for SDM requirements in MODE 2 with $K_{eff} < 1.0$ and MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

ACTIONS

A.1.1, A.1.2, and A.2

When the shutdown bank is not within insertion limit, verification of SDM or initiation of boration to regain SDM within 1 hour is required, since the SDM in MODE 1 and MODE 2 with $K_{eff} \geq 1.0$ is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"). If the shutdown bank is not within the insertion limit, then SDM will be verified by performing a reactivity balance calculation, taking into account RCS boron concentration, core power defect, control bank position, RCS average temperature, fuel burnup based on gross thermal energy generation, xenon concentration, samarium concentration, and isothermal temperature coefficient (ITC).

(continued)

BASES

ACTIONS

A.1.1, A.1.2, and A.2 (continued)

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the simultaneous occurrence of either a LOCA, loss of flow accident, ejected rod accident, or other accident during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability. Two hours is allowed to restore the shutdown bank to within the insertion limit. This time limit is necessary because the available SDM may be significantly reduced, with the shutdown bank not within the insertion limit. The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

B.1

If Required Actions A.1 and A.2 cannot be completed within the associated Completion Times, the plant must be brought to a MODE where the LCO is not applicable. To achieve this status, the plant must be placed in MODE 2 with $k_{eff} < 1.0$ within a Completion Time of 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Since the shutdown bank is positioned manually by the control room operator, a verification of shutdown bank position at a Frequency of every 12 hours is adequate to ensure that the bank is within the insertion limit. Also, the 12 hour Frequency takes into account other information available in the control room for the purpose of monitoring the status of shutdown rods.

(continued)

BASES (continued)

REFERENCES

1. Atomic Industrial Forum (AIF) GDC 27, 28, 29, and 32, Issued for comment July 10, 1967.
2. 10 CFR 50.46.
3. UFSAR, Chapter 15.
4. UFSAR, Section 15.1.5.
5. UFSAR, Section 15.4.1.
6. UFSAR, Section 15.4.2.
7. UFSAR, Section 15.4.6.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods define the deepest insertion into the core with respect to core power which is allowed and are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available ejected rod worth, SHUTDOWN MARGIN (SDM), and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are Atomic Industrial Forum (AIF) GDC 27, 28, 29, and 32 (Ref. 1), and 10 CFR 50.46 (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and a shutdown bank. Each bank is further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and one shutdown bank at Ginna Station. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control bank insertion limits are specified in the COLR. The control banks are required to be at or above the insertion limit lines.

The insertion limits figure in the COLR also indicates how the control banks are moved in an overlap pattern. Overlap is the distance travelled together by two control banks.

(continued)

BASES

BACKGROUND (continued)

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally controlled automatically by the Rod Control System, but can also be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating or diluting). The control banks must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power operations. The fully withdrawn position is defined in the COLR. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity changes associated with large changes in RCS temperature.

The rod insertion limit monitor is used to verify control rod insertion on a continuous basis and will provide an alarm whenever the control bank insertion deviates from the rod insertion limits specified in the COLR. Verification that the control banks are within the insertion limit is made every 12 hours (SR 3.1.6.2). When the rod insertion limit monitor is inoperable a verification that the rod positions are within the limit must be made more frequently (SR 3.1.6.3).

The control banks are moved in an overlap pattern, using the following withdrawal sequence: When control bank A reaches a predetermined height in the core, control bank B begins to move out with control bank A. Control bank A stops at the fully withdrawn position, and control bank B continues to move out. When control bank B reaches a predetermined height, control bank C begins to move out with control bank B. This sequence continues until control banks A, B, and C are at the fully withdrawn position, and control bank D is near the fully withdrawn position at RTP. The insertion sequence is the opposite of the withdrawal sequence (i.e., bank D is inserted first) but follows the same overlap pattern. The control rods are arranged in a radially symmetric pattern, so that control bank motion does not introduce radial asymmetries in the core power distributions.

(continued)

BASES

BACKGROUND (continued)

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.4, "Rod Group Alignment Limits," LCO 3.1.5, "Shutdown Bank Insertion Limit," LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the shutdown and control bank insertion limits restrict the reactivity that could be added in the event of a rod ejection accident, and ensure the required SDM is maintained.

Operation within the AFD, QPTR, shutdown and control bank insertion and alignment LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Trip System (RTS) trip function.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

On a reactor trip, all RCCAs (shutdown bank and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown bank shall be at or above the insertion limit and available to insert the maximum amount of negative reactivity on a reactor trip signal. The control banks may be partially inserted in the core, as allowed by LCO 3.1.6, "Control Bank Insertion Limits." The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") following a reactor trip from full power. The combination of control banks and the shutdown bank (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power, and to maintain the required SDM at rated no load temperature (Ref. 3). The control bank insertion limits also limit the reactivity worth of an ejected control bank rod.

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that:

a. There be no violations of:

    1. Specified acceptable fuel design limits, or

    2. Reactor Coolant System pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the control bank insertion limits affect safety analysis involving core reactivity and power distributions (Refs. 4, 5, 6, and 7).

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes the maximum worth RCCA remains fully withdrawn upon trip (Refs. 4, 5, 6, and 7).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worths. The control and shutdown bank insertion limits, together with AFD, QPTR and the control and shutdown bank alignment limits, ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Refs. 4, 5, 6, and 7). The control bank insertion, sequence and overlap limits satisfy Criterion 2 of the NRC Policy Statement, in that they are initial conditions assumed in the safety analysis.
LCO	The limits on control banks sequence, overlap, and insertion, as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is limited, and ensuring adequate negative reactivity insertion is available on trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion. The rod insertion limit monitor is used to verify control rod insertion on a continuous basis and will provide an alarm whenever the control bank insertion deviates from the rod insertion limits specified in the COLR. Verification that the control banks are within the insertion limit is made every 12 hours (SR 3.1.6.2). When the rod insertion limit monitor is inoperable a verification that the rod positions are within the limit must be made more frequently (SR 3.1.6.3). The LCO is modified by a Note indicating the LCO requirements are suspended during the performance of SR 3.1.4.3. This SR verifies the freedom of the rods to move, and requires the control bank to move below the LCO limits, which would violate the LCO.

(continued)

BASES (continued)

APPLICABILITY

The control bank insertion, sequence, and overlap limits shall be maintained with the reactor in MODE 1 and MODE 2 with $k_{eff} \geq 1.0$. These limits must be maintained, since they preserve the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions. Applicability in MODE 2 with $k_{eff} < 1.0$ and MODES 3, 4, 5, and 6 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

ACTIONS

A.1.1, A.1.2, and A.2

When the control banks are outside the acceptable insertion limits, out of sequence, or in the wrong overlap configuration, they must be restored to within those limits. This restoration can occur in two ways:

a. Reducing power to be consistent with rod position; or

b. Moving rods to be consistent with power.

Also, verification of SDM or initiation of boration to regain SDM within 1 hour is required, since the SDM in MODES 1 and 2 is normally ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"). If control banks are not within their limits, then SDM will be verified by performing a reactivity balance calculation, taking into account RCS boron concentration, core power defect, control bank position, RCS average temperature, fuel burnup based on gross thermal energy generation, xenon concentration, samarium concentration, and isothermal temperature coefficient (ITC).

(continued)

BASES

ACTIONS

A.1.1, A.1.2, and A.2 (continued)

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the occurrence of either a LOCA, loss of flow accident, ejected rod accident, or other accident during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability. Thus, the allowed Completion Time of 2 hours for restoring the banks to within the insertion, sequence, and overlap limits provides an acceptable time for evaluating and repairing minor problems.

B.1

If Required Actions A.1 and A.2 cannot be completed within the associated Completion Times, the plant must be brought to MODE 2 with $K_{eff} < 1.0$, where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits. The Frequency of within 4 hours prior to achieving criticality ensures that the estimated control bank position is within the limits specified in the COLR shortly before criticality is reached.

SR 3.1.6.2

With an OPERABLE bank insertion limit monitor (i.e., the PPCS), verification of the control bank insertion limits at a Frequency of 12 hours is sufficient to ensure OPERABILITY of the bank insertion limit monitor and to detect control banks that may be approaching the insertion limits since, normally, very little rod motion occurs in 12 hours.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.6.3

When the insertion limit monitor (i.e., the PPCS) becomes inoperable, no control room alarm is available between the normal 12 hour frequency to alert the operators of a control bank not within the insertion limits. A reduction of the Frequency to every 4 hours provides sufficient monitoring of control rod insertion when the monitor is inoperable. Verification of the control bank position at a Frequency of 4 hours is sufficient to detect control banks that may be approaching the insertion limits.

This SR is modified by a Note that states that performance of this SR in only necessary when the rod insertion limit monitor is inoperable.

SR 3.1.6.4

When control banks are maintained within their insertion limits as required by SR 3.1.6.2 and SR 3.1.6.3 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. A Frequency of 12 hours is consistent with the insertion limit check above in SR 3.1.6.2.

REFERENCES

1. Atomic Industrial Forum (AIF) GDC 27, 28, 29, and 32, Issued for comment July 10, 1967.
2. 10 CFR 50.46.
3. UFSAR, Chapter 15.
4. UFSAR, Section 15.1.5.
5. UFSAR, Section 15.4.1.
6. UFSAR, Section 15.4.2.
7. UFSAR, Section 15.4.6.

B 3.1 REACTIVITY CONTROL SYSTEM

B 3.1.7 Rod Position Indication

BASES

BACKGROUND

The OPERABILITY (i.e., trippability), including position indication, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SHUTDOWN MARGIN (SDM). Rod position indication is required to assess OPERABILITY and misalignment.

According to the Atomic Industrial Forum (AIF) GDC 12 and 13 (Ref. 1), instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. LCO 3.1.7 is required to ensure OPERABILITY of the control rod position indicators to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits.

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM. Limits on control rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are movable neutron absorbing devices which are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms (CRDMs). Each CRDM moves its RCCA one step (approximately 5/8 inch) at a time, but at varying rates (steps per minute) depending on the signal output from the Rod Control System.

(continued)

BASES

BACKGROUND (continued)

The RCCAs are divided among control banks and a shutdown bank. Control banks are used to compensate for changes in reactivity due to variations in operating conditions of the reactor such as coolant temperature, power level, boron or xenon concentration. The shutdown bank provides additional shutdown reactivity such that the total shutdown worth of the bank is adequate to provide shutdown for all operating and hot zero power conditions with the single RCCA of highest reactivity worth fully withdrawn. Each bank is further subdivided into groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion but always within one step of each other. There are four control banks and one shutdown bank at Ginna Station.

The axial position of shutdown rods and control rods is indicated by two separate and independent systems: the Bank Demand Position Indication System (commonly called group step counters) and the Microprocessor Rod Position Indication (MRPI) System.

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± ⅝ inch), but if a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

(continued)

BASES

BACKGROUND (continued)

The MRPI System also provides a highly accurate indication of actual control rod position, but at a lower precision than the step counters. The MRPI system consists of one digital detector assembly per rod. All the detector assemblies consist of one coil stack which is multiplexed and becomes input to two redundant MRPI signal processors. Each signal processor independently monitors all rods and senses a rod bottom for any rod. The MRPI system directly senses rod position in intervals of 12 steps for each rod. The digital detector assemblies consist of 20 discrete coil pairs spaced at 12-step intervals. The true rod position is always within ± 8 steps of the indicated position (± 6 steps due to the 12-step interval and ± 2 steps transition uncertainty due to processing and coil sensitivity). With an indicated deviation of 12 steps between the group step counter and MRPI, the maximum deviation between actual rod position and the demand position would be 20 steps, or 12.5 inches.

APPLICABLE SAFETY ANALYSES

Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2), with control or shutdown rods operating outside their limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod worth limits, and with minimum SDM (LCO 3.1.5, "Shutdown Bank Insertion Limit," and LCO 3.1.6, "Control Bank Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, "Rod Group Alignment Limits"). Control rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions.

The control rod position indicator channels satisfy Criterion 2 of the NRC Policy Statement. The control rod position indicators monitor control rod position, which is an initial condition of the accident.

(continued)

BASES (continued)

LCO

LCO 3.1.7 specifies that the MRPI System and the Bank Demand Position Indication System be OPERABLE. For the control rod position indicators to be OPERABLE requires the following:

a. For the MRPI System there are no failed coils and rod position indication is available on the MRPI screen (in either the control room or relay room) or the plant process computer system; and

b. The Bank Demand Indication System has been calibrated either in the fully inserted position or to the MRPI System.

The 12 step agreement limit between the Bank Demand Position Indication System and the MRPI System as required by SR 3.1.7.1 indicates that the Bank Demand Position Indication System is adequately calibrated, and can be used for indication of control rod bank position. A deviation of less than the allowable 12 step agreement limit, in position indication for a single control rod, ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the analysis.

The MRPI system is designed with error detection such that when a fault occurs in the binary data received from the coil stacks or processing unit an alarm is annunciated at the MRPI display. When the fault clears, the system provides self validation of data integrity and returns to its normal display mode. Because of the digital nature of the system and its inherent diagnostic features, intermittent data alarms can mask position indication and generate the perception that a single rod position is unmonitored. For a single rod position indication failure, MRPI is considered OPERABLE if a fault occurs and clears within five minutes and the indicated position is within expected values.

These requirements ensure that control rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged. OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned control rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

(continued)

BASES (continued)

APPLICABILITY

The requirements on the MRPI and step counters are only applicable in MODE 1 and MODE 2 with $K_{eff} \geq 1.0$ (consistent with LCO 3.1.4 and LCO 3.1.5, and LCO 3.1.6), because these are the only MODES in which the reactor is critical, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System. See LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," for SDM requirements in MODE 2 with $K_{eff} < 1.0$ and MODES 3, 4, and 5 and LCO 3.9.1, "Boron Concentration," for boron concentration requirements during MODE 6.

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable MRPI per group and each demand position indicator per bank. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

A.1

When one MRPI per group fails, the position of the rod can still be determined by use of the movable incore detectors. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Action of B.1 or B.2 below is required. Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

(continued)

BASES

ACTIONS (continued)

A.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors.

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above.

B.1 and B.2

When one or more rods with inoperable position indicators (i.e., MRPI) have been moved > 24 steps in one direction since the position was last determined, the Required Actions of A.1 and A.2 are still appropriate but must be initiated promptly under Required Action B.1 to begin verifying that these rods are still properly positioned, relative to their group positions. The allowed Completion Time of 4 hours provides an acceptable period of time to verify the rod positions.

Acceptable verification of rod position within 4 hours re-initiates the clock for Required Action A.1.

If, within 4 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP within 8 hours to avoid undesirable power distributions that could result from continued operation at > 50% RTP, if one or more rods are misaligned by more than 24 steps.

(continued)

BASES

ACTIONS (continued)

C.1.1 and C.1.2

With one demand position indicator per bank inoperable, the rod positions can be determined by the MRPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indicators are OPERABLE and the most withdrawn rod and the least withdrawn rod are ≤ 12 steps from the OPERABLE demand position indicator for that bank within the allowed Completion Time of once every 8 hours is adequate. This ensures that most withdrawn and least withdrawn rod are no more than 24 steps apart which is less than the accident analysis assumption of 25 steps. This verification can be an examination of logs, administrative controls, or other information that shows that all MRPIs in the affected bank are OPERABLE.

C.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position will not cause core peaking to approach the core peaking factor limits.

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 2 with $K_{eff} < 1.0$ within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

E.1

With more than one MRPI per group inoperable for one or more groups or more than one demand position indicator per bank inoperable for one or more banks, an immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Verification that the MRPI agrees with the group demand position within 12 steps for the full indicated range of rod travel ensures that the MRPI is operating correctly. Since the MRPI does not display the actual shutdown rod positions between 0 and 230 steps, only points within the indicated ranges are required in comparison.

This Surveillance is performed during a plant outage or during plant startup, prior to reactor criticality after each removal of the reactor head due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. Atomic Industrial Forum (AIF) GDC 12 and 13, Issued for comment July 10, 1967.

2. UFSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 PHYSICS TESTS Exceptions – MODE 2

BASES

BACKGROUND

The primary purpose of the MODE 2 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow certain PHYSICS TESTS to be performed.

Section XI of 10 CFR 50, Appendix B (Ref. 1), requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the plant. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program are to:

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in the design and analysis;

c. Verify the assumptions used to predict plant response;

d. Ensure that installation of equipment in the facility has been accomplished in accordance with the design; and

e. Verify that the operating and emergency procedures are adequate.

To accomplish these objectives, testing is performed prior to initial criticality; during startup, low power, power ascension, and at power operation; and after each refueling. The PHYSICS TESTS requirements for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions and that the core can be operated as designed.

(continued)

BASES

BACKGROUND (continued)

PHYSICS TESTS procedures are written and approved in accordance with established formats. The procedures include all information necessary to permit a detailed execution of the testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures, and test results are approved prior to continued power escalation and long term power operation.

The PHYSICS TESTS performed at Ginna Station for reload fuel cycles in MODE 2 include:

a. Critical Boron Concentration — Control Rods Withdrawn;

b. Critical Boron Concentration — Control Rods Inserted;

c. Control Rod Worth; and

d. Isothermal Temperature Coefficient (ITC).

These and other supplementary tests may be required to calibrate the nuclear instrumentation or to diagnose operational problems. These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance as described below.

a. The Critical Boron Concentration — Control Rods. Withdrawn Test measures the critical boron concentration at hot zero power (HZP). With all rods out, bank D is at or near its fully withdrawn position. HZP is where the core is critical (k_{eff} = 1.0), and the Reactor Coolant System (RCS) is at design temperature and pressure for zero power. Performance of this test could violate LCO 3.1.3, "Moderator Temperature Coefficient (MTC)."

(continued)

BASES

BACKGROUND (continued)

b. The Critical Boron Concentration — Control Rods Inserted Test measures the critical boron concentration at HZP, with a bank having a worth of at least 1% Δk/k fully inserted into the core. This test is used to measure the differential boron worth. With the core at HZP and all banks fully withdrawn, the boron concentration of the reactor coolant is gradually lowered in a continuous manner. The selected bank is then inserted to make up for the decreasing boron concentration until the selected bank has been moved over its entire range of travel. The reactivity resulting from each incremental bank movement is measured with a reactivity computer. The difference between the measured critical boron concentration with all rods fully withdrawn and with the bank inserted is determined. The differential boron worth is determined by dividing the measured bank worth by the measured boron concentration difference. Performance of this test could violate LCO 3.1.4, "Rod Group Alignment Limits;" LCO 3.1.5, "Shutdown Bank Insertion Limit;" or LCO 3.1.6, "Control Bank Insertion Limits."

c. The Control Rod Worth Test is used to measure the reactivity worth of selected control banks. This test is performed at HZP and has two alternative methods of performance. The first method, the Boron Exchange Method, varies the reactor coolant boron concentration and moves the selected control bank in response to the changing boron concentration. The reactivity changes are measured with a reactivity computer. This sequence is repeated for the remaining control banks. The second method, the Boron Endpoint Method, moves the selected control bank over its entire length of travel and then varies the reactor coolant boron concentration to achieve HZP criticality again. The difference in boron concentration is the worth of the selected control bank. This sequence is repeated for the remaining control banks. Performance of this test could violate LCO 3.1.4, LCO 3.1.5, or LCO 3.1.6.

(continued)

BASES

BACKGROUND (continued)

d. The ITC Test measures the ITC of the reactor. This test is performed at HZP using the Slope Method. The Slope Method varies RCS temperature in a slow and continuous manner. The reactivity change is measured with a reactivity computer as a function of the temperature change. The ITC is the slope of the reactivity versus the temperature plot. The test is repeated by reversing the direction of the temperature change, and the final ITC is the average of the two calculated ITCs. The Moderator Temperature Coefficient (MTC) at BOL, 70% RTP and at EOL is determined from the measured ITC. This test satisfies the requirements of SR 3.1.3.1 and SR 3.1.3.2. Performance of this test could violate LCO 3.4.2, "RCS Minimum Temperature for Criticality."

APPLICABLE SAFETY ANALYSES

The fuel is protected by multiple LCOs that preserve the initial conditions of the core assumed during the safety analyses. The methods for development of these LCOs, that are excepted by this LCO, are described in the Westinghouse Reload Safety Evaluation Methodology Report (Ref. 3). The above mentioned PHYSICS TESTS, and other tests that may be required to calibrate nuclear instrumentation or to diagnose operational problems, may require the operating control or process variables to deviate from their LCO limitations.

The UFSAR defines requirements for initial testing of the facility, including PHYSICS TESTS. Reference 4 summarizes the initial zero, low power, and power tests. Reload fuel cycle PHYSICS TESTS are performed in accordance with Technical Specification requirements, fuel vendor guidelines and established industry practices which are consistent with the PHYSICS TESTS described in References 5 and 6. Although these PHYSICS TESTS are generally accomplished within the limits of all LCOs, conditions may occur when one or more LCOs must be suspended to make completion of PHYSICS TESTS possible or practical. This is acceptable as long as the fuel design criteria are not violated. The requirements specified in the following LCOs may be suspended for PHYSICS TESTING:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

LCO 3.1.3, "Moderator Temperature Coefficient (MTC)";
LCO 3.1.4, "Rod Group Alignment Limits";
LCO 3.1.5, "Shutdown Bank Insertion Limit";
LCO 3.1.6, "Control Bank Insertion Limits"; and
LCO 3.4.2, "RCS Minimum Temperature for Criticality".

When these LCOs are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the power level is limited to ≤ 5% RTP, the reactor coolant temperature is kept ≥ 530°F, and SDM is within the limits specified in the COLR.

The PHYSICS TESTS include measurement of core nuclear parameters or the exercise of control components that affect process variables. Among the process variables involved are AFD and QPTR, which represent initial conditions of the plant safety analyses. Also involved are the movable control components (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR.

PHYSICS TESTS meet the criteria for inclusion in the Technical Specifications, since the components and process variable LCOs suspended during PHYSICS TESTS meet Criteria 1, 2, and 3 of the NRC Policy Statement.

LCO

This LCO allows the reactor parameters of MTC and minimum temperature for criticality to be outside their specified limits to conduct PHYSICS TESTS in MODE 2, to verify certain core physics parameters. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. Operation beyond specified limits is permitted for the purpose of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

The requirements of LCO 3.1.3, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 may be suspended during the performance of PHYSICS TESTS provided:

a. THERMAL POWER is maintained ≤ 5% RTP;

b. RCS lowest loop average temperature is ≥ 530°F; and

c. SDM is within the limits specified in the COLR.

(continued)

BASES (continued)

APPLICABILITY

This LCO is applicable when performing low power PHYSICS TESTS. The applicable PHYSICS TESTS are performed in MODE 2 at HZP.

ACTIONS

A.1 and A.2

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification within 1 hour.

B.1

When THERMAL POWER is > 5% RTP, the only acceptable action is to open the reactor trip breakers (RTBs) to prevent operation of the reactor beyond its design limits since a MODE change has occurred. Immediately opening the RTBs will shut down the reactor and prevent operation of the reactor outside of its design limits.

C.1

When the RCS loop with the lowest T_{avg} is < 530°F, the appropriate action is to restore T_{avg} to within its specified limit. The allowed Completion Time of 15 minutes provides time for restoring T_{avg} to within limits without allowing the plant to remain in an unacceptable condition for an extended period of time. Operation with the reactor critical and with temperature below 530°F could violate the assumptions for accidents analyzed in the safety analyses.

(continued)

BASES

ACTIONS (continued)

D.1

If Required Action C.1 cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within an additional 15 minutes. The Completion Time of 15 additional minutes is reasonable, based on operating experience, for reaching MODE 3 from MODE 2 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

The power range and intermediate range neutron detectors must be verified to be OPERABLE in MODE 2 by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." A CHANNEL OPERATIONAL TEST is performed on each power range and intermediate range channel within 7 days prior to criticality. This will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS. The 7 day time limit is sufficient to ensure that the instrumentation is OPERABLE shortly before initiating PHYSICS TESTS.

SR 3.1.8.2

Verification that the RCS lowest loop T_{avg} is ≥ 530°F will ensure that the plant is not operating in a condition that could invalidate the safety analyses. Verification of the RCS temperature at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.8.3

Verification that THERMAL POWER is < 5% RTP using the NIS detectors will ensure that the plant is not operating in a condition that could invalidate the safety analyses. Verification of the THERMAL POWER at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

SR 3.1.8.4

The SDM is verified by comparing the RCS boron concentration to a SHUTDOWN MARGIN requirement curve that was generated by taking into account estimated RCS boron concentrations, core power defect, control bank position, RCS average temperature, fuel burnup based on gross thermal energy generation, xenon concentration, samarium concentration, and isothermal temperature coefficient (ITC).

The Frequency of 24 hours is based on the generally slow change in required boron concentration and on the low probability of an accident occurring without the required SDM.

REFERENCES

1. 10 CFR 50, Appendix B, Section XI.
2. 10 CFR 50.59.
3. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology Report," July 1985.
4. UFSAR, Section 14.6.
5. Letter from R. W. Kober (RGE) to T. E. Murley (NRC), Subject: "Startup Reports," dated July 9, 1984.
6. Letter from J. P. Durr (NRC) to B. A. Snow (RGE), Subject: "Inspection Report No. 50-244/88-06," dated April 28, 1988.

3.2 POWER DISTRIBUTION LIMITS

3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$)

LCO 3.2.1 $F_Q(Z)$ shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. $F_Q(Z)$ not within limit.	A.1 Reduce THERMAL POWER ≥ 1% RTP for each 1% $F_Q(Z)$ exceeds limit.	15 minutes
	<u>AND</u>	
	A.2 Reduce AFD acceptable operation limits ≥ 1% for each 1% $F_Q(Z)$ exceeds limit.	8 hours
	<u>AND</u>	
	A.3 Reduce Power Range Neutron Flux—High trip setpoints ≥ 1% for each 1% $F_Q(Z)$ exceeds limit.	72 hours
	<u>AND</u>	
	A.4 Reduce Overpower ΔT and Overtemperature ΔT trip setpoints ≥ 1% for each 1% $F_Q(Z)$ exceeds limit.	72 hours
	<u>AND</u>	(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.5	Perform SR 3.2.1.1 or SR 3.2.1.2.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.1.1	Verify measured values of $F_Q(Z)$ are within limits specified in the COLR.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> 31 EFPD thereafter

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.2.1.2	---NOTE--- Only required to be performed if one power range channel is inoperable with THERMAL POWER ≥ 75% RTP. ------	
	Verify measured values of $F_Q(Z)$ are within limits specified in the COLR.	Once within 24 hours and every 24 hours thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

LCO 3.2.2 $F^N_{\Delta H}$ shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. $F^N_{\Delta H}$ not within limit.	A.1 Reduce THERMAL POWER $\geq$ 1% RTP for each 1% $F^N_{\Delta H}$ exceeds limit.	15 minutes
	<u>AND</u>	
	A.2 Reduce Power Range Neutron Flux – High trip setpoints $\geq$ 1% for each 1% $F^N_{\Delta H}$ exceeds limit.	72 hours
	<u>AND</u>	
	A.3 Reduce Overpower ΔT and Overtemperature ΔT trip setpoints $\geq$ 1% for each 1% $F^N_{\Delta H}$ exceeds limit.	72 hours
	<u>AND</u>	
	A.4 Perform SR 3.2.2.1 or SR 3.2.2.2.	Prior to increasing THERMAL POWER above the limit of Required Action A.1

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify $F^N_{\Delta H}$ is within limits specified in the COLR.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP AND 31 EFPD thereafter
SR 3.2.2.2	-------------------NOTE------------------- Only required to be performed if one power range channel is inoperable with THERMAL POWER ≥ 75% RTP. -- Verify $F^N_{\Delta H}$ is within limits specified in the COLR.	Once within 24 hours and every 24 hours thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.3 AXIAL FLUX DIFFERENCE (AFD)

LCO 3.2.3 The AFD monitor alarm shall be OPERABLE and AFD:

a. Shall be maintained within the target band about the target flux difference with THERMAL POWER ≥ 90% RTP. The target band is specified in the COLR.

b. May deviate outside the target band with THERMAL POWER < 90% RTP but ≥ 50% RTP, provided AFD is within the acceptable operation limits and cumulative penalty deviation time is ≤ 1 hour during the previous 24 hours. The acceptable operation limits are specified in the COLR.

c. May deviate outside the target band with THERMAL POWER < 50% RTP.

---------------------------NOTES---------------------------

1. The AFD shall be considered outside the target band when the average of four OPERABLE excore channels indicate AFD to be outside the target band. If one excore detector is out of service, the remaining three detectors shall be used to derive the average.

2. Penalty deviation time shall be accumulated on the basis of a 1 minute penalty deviation for each 1 minute of power operation with THERMAL POWER ≥ 50% RTP, and AFD outside the target band.

3. Penalty deviation time shall be accumulated on the basis of a 0.5 minute penalty deviation for each 1 minute of power operation with THERMAL POWER > 15% RTP and < 50% RTP, and AFD outside the target band.

4. A total of 16 hours of operation may be accumulated with AFD outside the target band without penalty deviation time during surveillance of power range channels in accordance with SR 3.3.1.6.

APPLICABILITY: MODE 1 with THERMAL POWER > 15% RTP.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. THERMAL POWER $\geq$ 90% RTP. AND AFD not within the target band.	A.1	Restore AFD to within target band.	15 minutes
B. Required Action and associated Completion Time of Condition A not met.	B.1	Reduce THERMAL POWER to < 90% RTP.	15 minutes
C. THERMAL POWER < 90% RTP and $\geq$ 50% RTP with cumulative penalty deviation time > 1 hour during the previous 24 hours. OR THERMAL POWER < 90% RTP and $\geq$ 50% RTP with AFD not within the target band and not within the acceptable operation limits.	C.1	Reduce THERMAL POWER to < 50% RTP.	30 minutes

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. THERMAL POWER ≥ 90% RTP. AND AFD monitor alarm inoperable.	D.1 Perform SR 3.2.3.2.	Once every 15 minutes
E. THERMAL POWER < 90% RTP. AND AFD monitor alarm inoperable.	E.1 Perform SR 3.2.3.3.	Once every 1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.3.1	Verify AFD monitor is OPERABLE.	12 hours
SR 3.2.3.2	-------------------NOTES------------------- 1. Only required to be performed if AFD monitor alarm is inoperable when THERMAL POWER ≥ 90% RTP. 2. Assume logged values of AFD exist during the preceding 24 hour time interval if actual AFD values are not available. --- Verify AFD is within limits and log AFD for each OPERABLE excore channel.	Once within 15 minutes and every 15 minutes thereafter
SR 3.2.3.3	-------------------NOTES------------------- 1. Only required to be performed if AFD monitor alarm is inoperable when THERMAL POWER < 90% RTP. 2. Assume logged values of AFD exist during the preceding 24 hour time interval if actual AFD values are not available. --- Verify AFD is within limits and log AFD for each OPERABLE excore channel.	Once within 1 hour and every 1 hour thereafter

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.2.3.4	Update target flux difference.	Once within 31 EFPD after each refueling **AND** 31 EFPD thereafter
SR 3.2.3.5	--------------------NOTE------------------- The initial target flux difference after each refueling may be determined from design predictions. --- Determine, by measurement, the target flux difference.	Once within 31 EFPD after each refueling **AND** 92 EFPD thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.4 QUADRANT POWER TILT RATIO (QPTR)

LCO 3.2.4 The QPTR monitor alarm shall be OPERABLE and QPTR shall be ≤ 1.02.

APPLICABILITY: MODE 1 with THERMAL POWER > 50% RTP.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. QPTR not within limit.	A.1	Limit THERMAL POWER to ≥ 3% below RTP for each 1% of QPTR > 1.00.	2 hours
	AND		
	A.2	Perform SR 3.2.4.2 and limit THERMAL POWER to ≥ 3% below RTP for each 1% of QPTR > 1.00.	Once per 12 hours
	AND		
	A.3	Perform SR 3.2.1.1 and SR 3.2.2.1.	24 hours AND Once per 7 days thereafter
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.4	Reevaluate safety analyses and confirm results remain valid for the duration of operation under this condition.	Prior to increasing THERMAL POWER above the limit of Required Action A.1.
	<u>AND</u>		
	A.5	--------NOTE--------- Perform Required Action A.5 only after Required Action A.4 is completed. --------------------- Normalize excore detector instrumentation to eliminate tilt.	Prior to increasing THERMAL POWER above the limit of Required Actions A.1 and A.2
	<u>AND</u>		(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.6	--------NOTES-------- 1. Only required to be performed if the cause of the QPTR alarm is not associated with inoperable QPTR instrumentation. 2. Required Action A.6 must be completed when Required Action A.5 is completed and Note 1, above, does not apply. 3. Only one of the Completion Times, whichever becomes applicable first, must be met. ---------------------	
		Perform SR 3.2.1.1 and SR 3.2.2.1.	Within 24 hours after reaching RTP <u>OR</u> Within 48 hours after increasing THERMAL POWER increased above the limits of Required Actions A.1 and A.2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1 Reduce THERMAL POWER to ≤ 50% RTP.	4 hours
C. QPTR monitor alarm inoperable.	C.1 Perform SR 3.2.4.3	Once within 24 hours and every 24 hours thereafter
	<u>OR</u>	
	C.2 Perform SR 3.2.1.2 and SR 3.2.2.2	Once within 24 hours and every 24 hours thereafter

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.4.1	Verify QPTR monitor alarm is OPERABLE.	12 hours
SR 3.2.4.2	-------------------NOTES------------------- 1. With one power range channel inoperable and THERMAL POWER < 75% RTP, the remaining three power range channels can be used for calculating QPTR. 2. With one power range channel inoperable and THERMAL POWER ≥ 75% RTP, perform SR 3.2.1.2 and SR 3.2.2.2. --- Verify QPTR is within limit by calculation.	7 days
SR 3.2.4.3	-------------------NOTES------------------- 1. Only required to be performed if the QPTR monitor alarm is inoperable. 2. With one power range channel inoperable and THERMAL POWER < 75% RTP, the remaining three power range channels can be used for calculating QPTR. 3. With one power range channel inoperable and THERMAL POWER ≥ 75% RTP, perform SR 3.2.1.2 and SR 3.2.2.2. --- Verify QPTR is within limit by calculation.	Once within 24 hours and every 24 hours thereafter

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$)

BASES

BACKGROUND

The purpose of the limits on the values of $F_Q(Z)$ is to limit the local (i.e., pellet) peak power density. The value of $F_Q(Z)$ varies along the axial height of the core (Z).

$F_Q(Z)$ is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and fuel rod dimensions adjusted for uncertainty. Therefore, $F_Q(Z)$ is a measure of the peak pellet power within the reactor core.

During power operation, the global power distribution is monitored by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which are directly and continuously measured process variables. Therefore, these LCOs preserve core limits on a continuous basis.

$F_Q(Z)$ is sensitive to fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution.

$F_Q(Z)$ is measured periodically using the incore detector system. Measurements are generally taken with the core at or near steady state conditions. With the measured three dimensional power distributions, it is possible to determine a measured value for $F_Q(Z)$. However, because this value represents a steady state condition, it does not include variations in the value of $F_Q(Z)$, which are present during a nonequilibrium situation such as load following when the plant changes power level to match grid demand peaks and valleys.

Core monitoring and control under transient conditions (i.e., Condition 1 events as described in Reference 1) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion, Sequence and Overlap Limits.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Limits on F_Q (Z) preclude core power distributions that violate the following fuel design criteria:

a. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hottest fuel rod in the core does not experience a DNB condition;

b. During a large break loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200°F (Ref. 2);

c. During an ejected rod accident, the energy deposition to the fuel will be below 200 cal/gm (Ref. 3); and

d. The control rods must be capable of shutting down the reactor with a minimum required SHUTDOWN MARGIN (SDM) with the highest worth control rod stuck fully withdrawn (Ref. 4).

Limits on $F_Q(Z)$ ensure that the value of the total peaking factor assumed as an initial condition in the accident analyses remains valid. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, the peak cladding temperature is typically most limiting.

The $F_Q(Z)$ limits provided in the COLR are based on the limits used in the LOCA analysis. $F_Q(Z)$ limits assumed in the LOCA analysis are typically limiting relative to (i.e., lower than) the $F_Q(Z)$ assumed in safety analyses for other accidents because of the requirements set forth in 10 CFR 50.46 (Ref. 2) and ECCS model development in accordance with the required features of the ECCS evaluation models provided in 20 CFR 50, Appendix K (Ref. 5). Therefore, this LCO provides conservative limits for other accidents.

$F_Q(Z)$ satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

The $F_Q(Z)$ shall be maintained within the limits of the relationships provided in the COLR.

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during either a large or small break LOCA (Refs. 6 and 7).

This LCO requires operation within the bounds assumed in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within the LOCA $F_Q(Z)$ limits. If $F_Q(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required.

Violating the LCO limits for $F_Q(Z)$ may produce unacceptable consequences if a design basis event occurs while $F_Q(Z)$ is outside its specified limits.

APPLICABILITY

The $F_Q(Z)$ limits must be maintained while in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is neither sufficient stored energy in the fuel nor sufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power.

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% for each 1% by which $F_Q(Z)$ exceeds its limit maintains an acceptable absolute power density. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time.

(continued)

BASES

ACTIONS (continued)

A.2

When core peaking factors are sufficiently high that LCO 3.2.1 does not permit operation at RTP, the acceptable operation limits for AFD are reduced. The acceptable operation limits are reduced 1% for each 1% by which $F_Q(Z)$ exceeds its limit. For example, if the measured $F_Q(Z)$ exceeds the limit by 3% and the acceptable operation limits for AFD are ± 11% at 90% RTP and ± 31% at 50% RTP, then the revised AFD Acceptable Operation Limits would be ± 8% at 90% RTP and ± 28% at 50% RTP. This ensures a near constant maximum linear heat rate in units of kilowatts per foot at the acceptable operation limits. The Completion Time of 8 hours for the change in setpoints is sufficient, considering the small likelihood of a severe transient in this relatively short time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1.

A.3

A reduction of the Power Range NeutronFlux—High trip setpoints by ≥ 1% for each 1% by which $F_Q(Z)$ exceeds its specified limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions since this trip setpoint helps protect reactor core safety limits. This reduction shall be made as follows, given an $F_Q(Z)$ limit of 2.32, a measured $F_Q(Z)$ of 2.4, and a Power Range Neutron Flux—High setpoint of 108%, the Power Range Neutron Flux—High setpoint must be reduced by at least 3.4% to 104.6%. The Completion Time of 72 hours is sufficient, considering the small likelihood of a severe transient in this period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1.

(continued)

BASES

ACTIONS (continued)

A.4

Reduction in the Overpower ΔT and Overtemperature ΔT trip setpoints by $\geq$ 1% for each 1% by which $F_Q(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions since these trip setpoints help protect reactor core safety limits. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1.

A.5

Verification that $F_Q(Z)$ has been restored to within its limit by performing SR 3.2.1.1 or SR 3.2.1.2 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1 ensures that core conditions during operation at higher power levels are consistent with safety analyses assumptions.

B.1

If the Required Actions of A.1 through A.5 cannot be met within their associated Completion Times, the plant must be placed in a MODE or Condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

Verification that $F_Q(Z)$ is within its limit involves increasing the measured values of $F_Q(Z)$ to allow for manufacturing tolerance and measurement uncertainties and then making a comparison with the limits. These limits are provided in the COLR. Specifically, the measured value of the Heat Flux Hot Channel Factor (F^M_Q) is increased by 3% to account for fuel manufacturing tolerances and by 5% for flux map measurement uncertainty for a full core flux map using the movable incore detector flux mapping system. This procedure is equivalent to increasing the directly measured values of $F_Q(Z)$ by 1.0815% before comparing with LCO limits.

Performing the Surveillance in MODE 1 prior to THERMAL POWER exceeding 75% RTP after each refueling ensures that $F_Q(Z)$ is within limit when RTP is achieved and provides confirmation of the nuclear design and the fuel loading pattern.

The Frequency of 31 EFPD is adequate for monitoring the change of power distribution with core burnup because the power distribution changes relatively slowly for this amount of fuel burnup. Accordingly, this Frequency is short enough that the $F_Q(Z)$ limit cannot be exceeded for any significant period of time.

SR 3.2.1.2

During power operation, the global power distribution is monitored by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which are directly and continuously measured process variables.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 (continued)

With an NIS power range channel inoperable, QPTR monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. Performing SR 3.2.1.2 at a Frequency of 24 hours provides an accurate alternative means for ensuring that F_Q remains within limits and the core power distribution is consistent with the safety analyses. A Frequency of 24 hours takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and perform a flux map.

This Surveillance is modified by a Note, which states that it is required only when one power range channel is inoperable and the THERMAL POWER is ≥ 75% RTP.

REFERENCES

1. American National Standard, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," N18.2-1973.
2. 10 CFR 50.46.
3. UFSAR, Section 15.4.5.1.
4. Atomic Industrial Forum (AIF) GDC 29, Issued for comment July 10, 1967.
5. 10 CFR 50, Appendix K.
6. UFSAR, Section 15.6.4.1.
7. UFSAR, Section 15.6.4.2.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the power density at any point in the core so that the fuel design criteria are not exceeded and the accident analysis assumptions remain valid. The design limits on local (pellet) and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location in the core during either normal operation or a postulated accident analyzed in the safety analyses.

$F^N_{\Delta H}$ is defined as the ratio of the integral of the linear power along the fuel rod with the highest integrated power to the average integrated fuel rod power. Therefore, $F^N_{\Delta H}$ is a measure of the maximum total power produced in a fuel rod. The $F^N_{\Delta H}$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least heat removal capability and thus the highest probability for departure from nucleate boiling (DNB).

$F^N_{\Delta H}$ is sensitive to fuel loading patterns, control bank insertion, and fuel burnup. $F^N_{\Delta H}$ typically increases with control bank insertion and typically decreases with fuel burnup.

$F^N_{\Delta H}$ is not directly measurable but is inferred from a power distribution map obtained with the movable incore detector system. Specifically, the results of the three dimensional power distribution map are analyzed by a computer to determine $F^N_{\Delta H}$. This factor is calculated at least every 31 EFPD. However, during power operation, the global power distribution is monitored by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which are directly and continuously measured process variables. Therefore, these LCOs preserve core limits on a continuous basis. $F^N_{\Delta H}$ and the QPTR LCO limit the radial component of the peaking factors.

(continued)

BASES

BACKGROUND (continued)

The COLR provides peaking factor limits that ensure that the design basis value for departure from nucleate boiling ratio (DNBR) is met for normal operation, operational transients, and any transient condition arising from events of moderate frequency. The DNB design basis precludes DNB and is met by limiting the minimum local DNB heat flux ratio. All DNB limited transient events are assumed to begin with an $F^N_{\Delta H}$ value that satisfies the LCO requirements.

The design method employed to meet the DNB design criterion for fuel assemblies is the Improved Thermal Design Procedure (ITDP). With the ITDP methodology, uncertainties in plant operating parameters, computer codes and DNB correlation predictions are considered statistically to obtain DNB uncertainty factors. Based on the DNB uncertainty factors, ITDP design limit DNBR values are determined in order to meet the DNB design criterion.

The ITDP design limit DNBR values are 1.34 and 1.33 for the typical and thimble cells, respectively, for fuel analyses with the WRB-2 correlation.

DNBR margin is maintained by performing the safety analyses to DNBR limits higher than the design limit DNBR values. This margin between the design and safety analysis limit DNBR values is used to offset known DNBR penalties (e.g., rod bow and transition core) and to provide DNBR margin for operating and design flexibility. The safety analysis DNBR values are 1.52 and 1.51 for the typical and thimble cells, respectively.

(continued)

BASES

BACKGROUND (continued)

For both the WRB-1 and WRB-2 correlations, the 95/95 DNBR correlation limit is 1.17. The W-3 DNB correlation is used where the primary DNBR correlations were developed based on mixing vane data and therefore are only applicable in the heated rod spans above the first mixing vane grid. The W-3 correlation, which does not take credit for mixing vane grids, is used to calculate DNBR values in the heated region below the first mixing vane grid. In addition, the W-3 correlation applies in the analysis of accident conditions where the system pressure is below the range of the primary correlations. For system pressures in the range of 500 to 1000 psia, the W-3 correlation limit is 1.45. For system pressures greater than 1000 psia, the W-3 correlation limit is 1.30.

Operation outside the LCO limits may produce unacceptable consequences if a DNB limiting event occurs. The DNB design basis ensures that there is no overheating of the fuel that results in possible cladding perforation with the release of fission products to the reactor coolant.

APPLICABLE SAFETY ANALYSES

Limits on $F^N_{\Delta H}$ preclude core power distributions that exceed the following fuel design limits:

a. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition;

b. During a large break loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200°F (Ref. 1);

c. During an ejected rod accident, the energy deposition to the fuel will be below 200 cal/gm (Ref. 2); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

For transients that may be DNB limited, the Reactor Coolant System flow and $F^N_{\Delta H}$ are the core parameters of most importance. The limits on $F^N_{\Delta H}$ ensure that the DNB design basis is met for normal operation, operational transients, and any transients arising from events of moderate frequency (i.e., Condition 1 events as described in Reference 4). The DNB design basis is met by limiting the minimum DNBR to the 95/95 DNB criterion.

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This functionality in $F^N_{\Delta H}$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, any DNB events in which the calculation of the core limits is modeled implicitly use this variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all transients that may be DNB limited are assumed to begin with an initial $F^N_{\Delta H}$ as a function of power level defined by the COLR limit equation.

The LOCA safety analysis indirectly models $F^N_{\Delta H}$ as an input parameter. The Nuclear Heat Flux Hot Channel Factor ($F_Q(Z)$) and the axial peaking factors are inserted directly into the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 1).

The fuel is protected in part by Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid. The following LCOs ensure this: LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)," and LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)."

$F^N_{\Delta H}$ is measured periodically using the movable incore detector system. Measurements are generally taken with the core at, or near, steady state conditions. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion, Sequence and Overlap Limits.

$F^N_{\Delta H}$ satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR.

The $F^N_{\Delta H}$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least heat removal capability and thus the highest probability for DNB.

The limiting value of $F^N_{\Delta H}$, described by the equation contained in the COLR, is the design radial peaking factor used in the plant safety analyses.

A power multiplication factor in this equation includes an additional margin for higher radial peaking from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of $F^N_{\Delta H}$ is allowed to increase 0.3% for every 1% RTP reduction in THERMAL POWER.

APPLICABILITY

The $F^N_{\Delta H}$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the fuel design limits for DNBR and PCT. Applicability in other modes is not required because there is neither sufficient stored energy in the fuel nor sufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F^N_{\Delta H}$ in MODES 2, 3, 4, and 5 have significant margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these modes.

(continued)

BASES (continued)

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% for each 1% by which $F^N_{\Delta H}$ exceeds its limit maintains an acceptable DNBR margin. When the $F^N_{\Delta H}$ limit is exceeded, the DNBR limit is not likely violated in steady state operation, because events that could significantly perturb the $F^N_{\Delta H}$ value (e.g., static control rod misalignment) are considered in the safety analyses. However, the DNBR limit may be violated if a DNB limiting event occurs. Reducing THERMAL POWER increases the DNB margin. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time.

A.2

A reduction of the Power Range Neutron Flux-High trip setpoints by ≥ 1% for each 1% by which $F^N_{\Delta H}$ exceeds its specified limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions and ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. This reduction shall be made as follows, given that the $F^N_{\Delta H}$ limit is exceeded by 3% and the Power Range Neutron Flux-High setpoint is 108%, the Power Range Neutron Flux-High setpoint must be reduced by at least 3% to 105%. The Completion Time of 72 hours is sufficient, considering the small likelihood of a severe transient in this period, and the preceding prompt reduction in THERMAL POWER in accordance with required action A.1.

A.3

Reduction in the Overpower ΔT and Overtemperature ΔT trip setpoints by ≥ 1% for each 1% by which $F^N_{\Delta H}$ exceeds its limit, ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1.

(continued)

BASES

ACTIONS (continued)

A.4

Verification that $F^N_{\Delta H}$ has been restored within its limit by performing SR 3.2.2.1 or SR 3.2.2.2 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1 ensures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is corrected, and core conditions during operation at higher power levels are consistent with safety analyses assumptions.

B.1

If the Required Actions of A.1 through A.4 cannot be met within their associated Completion Times, the plant must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

The allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The value of $F^N_{\Delta H}$ is determined by using the movable incore detector system to obtain a flux distribution map. A data reduction computer program then calculates the maximum value of $F^N_{\Delta H}$ from the measured flux distributions. The measured value of $F^N_{\Delta H}$ must be multiplied by 1.04 to account for measurement uncertainty before making comparisons to the $F^N_{\Delta H}$ limit.

After each refueling, $F^N_{\Delta H}$ must be determined in MODE 1 prior to exceeding 75% RTP. This requirement ensures that $F^N_{\Delta H}$ limits are met at the beginning of each fuel cycle.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1 (continued)

The Frequency of 31 EFPD is acceptable because the power distribution changes relatively slowly over this amount of fuel burnup. Accordingly, this Frequency is short enough that the $F^N_{\Delta H}$ limit cannot be exceeded for any significant period of operation. When the plant is already performing SR 3.2.2.2 to satisfy other requirements, SR 3.2.2.2 does not need to be suspended in order to perform SR 3.2.2.1 since the performance of SR 3.2.2.2 meets the requirements of SR 3.2.2.1.

SR 3.2.2.2

During power operation, the global power distribution is monitored by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which are directly and continuously measured process variables.

With an NIS power range channel inoperable, QPTR monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. Performing SR 3.2.2.2 at a Frequency of 24 hours provides an accurate alternative means for ensuring that $F^N_{\Delta H}$ remains within limits and the core power distribution is consistent with the safety analyses. A Frequency of 24 hours takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and perform a flux map.

This Surveillance is modified by a Note, which states that it is required only when one power range channel is inoperable and the THERMAL POWER is ≥ 75% RTP.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50.46.
2. UFSAR, Section 15.4.5.1.
3. Atomic Industrial Forum (AIF) GDC 29, Issued for comment July 10 1967.
4. American National Standard, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," N18.2-1973.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL FLUX DIFFERENCE (AFD)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the axial power distribution skewing to either the top or bottom of the core. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in axial power distribution control.

The operating scheme used to control the axial power distribution, Constant Axial Offset Control (CAOC), involves maintaining the AFD within a tolerance band around a burnup dependent target, known as the target flux difference, to minimize the variation of the axial peaking factor and axial xenon distribution during plant maneuvers.

The target flux difference is determined at equilibrium xenon conditions. The control banks must be positioned within the core in accordance with their insertion limits and Control Bank D should be inserted near its normal position (i.e., ≥ 210 steps withdrawn) for steady state operation at high power levels. The power level should be as near RTP as practical. The value of the target flux difference obtained under these conditions divided by the fraction of RTP is the target flux difference at RTP for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RTP value by the appropriate fractional THERMAL POWER level.

Periodic updating of the target flux difference value is necessary to follow the change of the flux difference at steady state conditions with burnup.

The Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$) and QUADRANT POWER TILT RATIO (QPTR) LCOs limit the radial component of the peaking factors.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The AFD is a measure of axial power distribution skewing to the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution and, to a lesser extent, reactor coolant temperature and boron concentrations. The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

The CAOC methodology (Ref. 1) entails:

a. Establishing an envelope of allowed power shapes and power densities;

b. Devising an operating strategy for the cycle that maximizes plant flexibility (maneuvering) and minimizes axial power shape changes;

c. Demonstrating that this strategy does not result in core conditions that violate the envelope of permissible core power characteristics; and

d. Demonstrating that this power distribution control scheme can be effectively supervised with excore detectors.

The limits on the AFD ensure that the Heat Flux Hot Channel Factor ($F_Q(Z)$) is not exceeded during either normal operation or in the event of xenon redistribution following power changes. The limits on the AFD also limit the range of power distributions that are assumed as initial conditions in analyzing Condition 2, 3, and 4 events (Ref. 2). This ensures that fuel cladding integrity is maintained for these postulated accidents. The most important Condition 4 event is the loss of coolant accident. The most significant Condition 3 event is the loss of flow accident. The most significant Condition 2 events are uncontrolled bank withdrawal and boration or dilution accidents. Condition 2 accidents, assumed to begin from within the AFD limits, are used to confirm the adequacy of Overpower ΔT and Overtemperature ΔT trip setpoints.

The limits on the AFD satisfy Criterion 2 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator, through either the manual operation of the control banks, or automatic motion of control banks responding to temperature deviations resulting from either manual operation of the Chemical and Volume Control System to change boron concentration, or from power level changes.

Signals are available to the operator to help define the power profile from the Nuclear Instrumentation System (NIS) excore neutron detectors (Ref. 3). Separate signals are taken from the top and bottom excore neutron detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom halves of a two section excore neutron detector in each detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as %Δ flux or %ΔI.

With THERMAL POWER ≥ 90% RTP (i.e., Part A of this LCO), the AFD must be kept within the target band about the target flux difference. The target band is provided in the COLR. With the AFD outside the target band with THERMAL POWER ≥ 90% RTP, the assumptions of the accident analyses may be violated. With THERMAL POWER < 90% RTP, the AFD may be outside the target band provided that the deviation time is restricted.

It is intended that the plant is operated with the AFD within the target band about the target flux difference. However, during rapid THERMAL POWER reductions, control bank motion may cause the AFD to deviate outside of the target band at reduced THERMAL POWER levels. This deviation does not affect the xenon distribution sufficiently to change the envelope of peaking factors that may be reached on a subsequent return to RTP with the AFD within the target band, provided the time duration of the deviation is limited. Accordingly, while THERMAL POWER is ≥ 50% RTP and < 90% RTP (i.e., Part B of this LCO), a 1 hour cumulative penalty deviation time limit, cumulative during the preceding 24 hours when > 15% RTP, is allowed during which the plant may be operated outside of the target band but within the acceptable operation limits provided in the COLR. The cumulative penalty time is the sum of penalty times as calculated by Notes 2 and 3 of this LCO.

(continued)

BASES

LCO (continued)

For THERMAL POWER levels > 15% RTP and < 50% RTP (i.e., Part C of this LCO), deviations of the AFD outside of the target band are less significant. The reduced penalty deviation time accumulation rate reflects this reduced significance. With THERMAL POWER < 15% RTP, AFD is not a significant parameter in the assumptions used in the safety analysis and, therefore, requires no limits. Because the xenon distribution produced at THERMAL POWER levels less than RTP does affect the power distribution as power is increased, unanalyzed xenon and power distribution is prevented by limiting the accumulated penalty deviation time.

The frequency of monitoring the AFD by the Plant Process Computer System (PPCS) is nominally once per minute providing an essentially continuous accumulation of penalty deviation time that allows the operator to accurately assess the status of the penalty deviation time. The inoperability of this monitor requires independent verification that AFD remains within limit and that the peaking factors assumed in the accident analyses remain valid.

(continued)

BASES

LCO (continued)

This LCO is modified by four Notes. The first Note states the conditions necessary for declaring the AFD outside of the target band. The required target band varies with axial burnup distribution, which in turn varies with the core average accumulated burnup. The target band defined in the COLR may provide one target band for the entire cycle or more than one band, each to be followed for a specific range of cycle burnup. The average of the four OPERABLE excore detectors is used to determine when AFD is outside the target band. If one excore detector is out of service, the remaining three detectors are used to derive the average AFD. The second and third Notes describe how the cumulative penalty deviation time is calculated. The second Note states that with THERMAL POWER ≥ 50% RTP the penalty deviation time is accumulated at the rate of 1 minute for each 1 minute of power operation with AFD outside the target band. The third Note states that with THERMAL POWER > 15% RTP and < 50% RTP the penalty deviation time is accumulated at the rate of 0.5 minutes for each 1 minute of power operation with AFD outside the target band. The cumulative penalty time is the sum of penalty times from Notes 2 and 3 of this LCO. The fourth Note addresses AFD outside of the target band during surveillances. For surveillance of the power range channels performed according to SR 3.3.1.6, deviation outside the target band is permitted for 16 hours and no penalty deviation time is accumulated. Some deviation in the AFD is required for doing the NIS calibration with the incore detector system. This calibration is performed every 92 days.

Violating the LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its limits.

(continued)

BASES (continued)

APPLICABILITY

AFD requirements are applicable in MODE 1 above 15% RTP. Above 50% RTP, the combination of THERMAL POWER and core peaking factors are the core parameters of primary importance in safety analyses (Ref. 1). Above 15% RTP, this LCO is applicable to ensure that the distributions of xenon are consistent with safety analysis assumptions.

At or below 15% RTP and for lower operating MODES, the stored energy in the fuel and the energy being transferred to the reactor coolant are low. Also, low signal levels in the excore channels may preclude obtaining valid AFD signals below 15% RTP. The value of the AFD in these conditions does not affect the consequences of the design basis events.

ACTIONS

<u>A.1</u>

With the AFD outside the target band and THERMAL POWER ≥ 90% RTP, the assumptions used in the accident analyses may be violated with respect to the maximum heat generation. Therefore, a Completion Time of 15 minutes is allowed to restore the AFD to within the target band because xenon distributions change little in this relatively short time.

<u>B.1</u>

If Required Action A.1 is not completed with the required Completion Time of 15 minutes, the axial xenon distribution starts to become skewed. Reducing THERMAL POWER to < 90% RTP places the core in a condition that has been analyzed and found to be acceptable, provided that the AFD is within the acceptable operation limits provided in the COLR.

The allowed Completion Time of 15 minutes to reduce THERMAL POWER to < 90% RTP allows for a controlled reduction in power without allowing the plant to remain in an unanalyzed condition for an extended period of time.

(continued)

BASES

ACTIONS (continued)

C.1

This Required Action must be implemented with THERMAL POWER < 90% RTP but ≥ 50% RTP if either the cumulative penalty deviation time is > 1 hour during the previous 24 hours, or the AFD is not within the target band and not within the acceptable operation limits.

With THERMAL POWER < 90% RTP but ≥ 50% RTP, operation with the AFD outside the target band is allowed for up to 1 hour if the AFD is within the acceptable operation limits provided in the COLR. With the AFD within these limits, the resulting axial power distribution is acceptable as an initial condition for accident analyses assuming the then existing xenon distributions. The 1 hour cumulative penalty deviation time restricts the extent of xenon redistribution. Without this limitation, unanalyzed xenon axial distributions may result from a different pattern of xenon buildup and decay. Reducing THERMAL POWER to < 50% RTP will put the reactor at a THERMAL POWER level at which the AFD is not a significant accident analysis parameter.

If the indicated AFD is outside the target band and outside the acceptable operation limits provided in the COLR, the peaking factors assumed in accident analysis may be exceeded with the existing xenon condition. Any AFD within the target band is acceptable regardless of its relationship to the acceptable operation limits. The Completion Time of 30 minutes allows for a prompt, yet orderly, reduction in power.

D.1

When the AFD monitor alarm is inoperable and THERMAL POWER is ≥ 90% RTP, the AFD measurement determined by the PPCS must be independently monitored to detect operation outside of the target band and to compute the penalty deviation time at a frequency of every 15 minutes to ensure that the plant does not operate in an unanalyzed condition. A Completion Time of 15 minutes is adequate to ensure that the AFD is within its limits at high THERMAL POWER levels and is consistent with the Completion Time for restoring AFD to within limits (Condition A).

(continued)

BASES

ACTIONS (continued)

E.1

When the AFD monitor alarm is inoperable and THERMAL POWER is < 90% RTP, the AFD measurement determined by the PPCS must be independently monitored to detect operation outside of the target band and to compute the penalty deviation time at a frequency of every hour to ensure that the plant does not operate in an unanalyzed condition. A Completion Time of 1 hour is adequate since the AFD may deviate from the target band for up to 1 hour using the methodology of Notes 2 and 3 of this LCO to calculate the cumulative penalty deviation time before corrective action is required.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

This SR is the verification that the AFD monitor is OPERABLE. This is normally accomplished by introducing a signal into the plant process computer to verify control room annunciation of AFD not within the target band. The Frequency of 12 hours is sufficient to ensure OPERABILITY of the AFD monitor since under normal plant operation, the AFD is not expected to significantly change.

SR 3.2.3.2

The AFD is monitored on a continuous basis using the Plant Process Computer System (PPCS) that has an AFD monitor alarm. The PPCS determines the 1 minute average of the OPERABLE excore detector outputs and provides an alarm message and a main control board annunciator immediately if the average AFD is outside the target band and then re-alarms when the cumulative penalty deviation time reaches 15 minute intervals within the previous 24 hours. The computer also sends an alarm message when the cumulative penalty deviation time is ≥ 1 hour within the previous 24 hours. This alarm message does not clear until the cumulative penalty deviation time is < 1 hour within the previous 24 hours.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.3.2 (continued)

With the AFD monitor alarm inoperable, the AFD measurement determined by the PPCS must be independently monitored to detect operation outside of the target band and to compute the penalty deviation time. During operation at ≥ 90% RTP, the AFD measurement is monitored at a Surveillance Frequency of 15 minutes to ensure that the AFD is within its limits at high THERMAL POWER levels. The AFD should be monitored and logged more frequently during periods of operation for which the power level or control bank positions are changing to allow corrective measures when the AFD is more likely to move outside the target band.

SR 3.2.3.2 is modified by two Notes. The first Note states that this surveillance is only required to be performed when the AFD monitor alarm is inoperable with THERMAL POWER ≥ 90% RTP. The second Note states that monitored and logged values of the AFD are assumed to exist for the preceding 24 hour interval in order for the operator to compute the cumulative penalty deviation time if AFD values cannot be obtained from the PPCS. Inoperability of the alarm does not necessarily prevent the actual AFD values from being available (e.g., from the computer logs or hand logs). AFD values for the preceding 24 hours can be obtained from the hourly PPCS printouts or hand logs.

SR 3.2.3.3

The AFD is monitored on a continuous basis using the PPCS that has an AFD monitor alarm. The PPCS determines the 1 minute average of the OPERABLE excore detector outputs and provides an alarm message and a main control board annunciator immediately if the average AFD is outside the target band and then re-alarms when the cumulative penalty deviation time reaches 15 minute intervals within the previous 24 hours. The computer also sends an alarm message when the cumulative penalty deviation time is ≥ 1 hour within the previous 24 hours. This alarm message does not clear until the cumulative penalty deviation time is < 1 hour within the previous 24 hours.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.3.3 (continued)

With the AFD monitor alarm inoperable, the AFD measurement determined by the PPCS must be independently monitored to detect operation outside of the target band and to compute the penalty deviation time. During operation at < 90% RTP, but > 15% RTP, the AFD measurement is monitored at a Surveillance Frequency of 1 hour to ensure that the AFD is within its limits. The Frequency of 1 hour is adequate since the AFD may deviate from the target band for up to 1 hour using the methodology of Notes 2 and 3 of this LCO to calculate the cumulative penalty deviation time before corrective action is required. The AFD should be monitored and logged more frequently in periods of operation for which the power level or control bank positions are changing to allow corrective measures when the AFD is more likely to move outside the target band.

SR 3.2.3.3 is modified by two Notes. The first Note states that this surveillance is only required to be performed when the AFD monitor alarm is inoperable with THERMAL POWER < 90% RTP. The second Note states that monitored and logged values of the AFD are assumed to exist for the preceding 24 hour interval in order for the operator to compute the cumulative penalty deviation time if AFD values cannot be obtained from the PPCS. Inoperability of the alarm does not necessarily prevent the actual AFD values from being available (e.g., from the computer logs or hand logs). AFD values for the preceding 24 hours can be obtained from the hourly PPCS printouts or hand logs.

SR 3.2.3.4

This Surveillance requires that the target flux difference be updated at a Frequency of 31 effective full power days (EFPD) to account for small changes that may occur in the target flux differences in that period due to burnup.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.3.4 (continued)

There are two methods by which this update can be completed. The first method requires measuring the target flux difference in accordance with SR 3.2.3.5. This measurement may be obtained using incore or excore instrumentation. The second method involves interpolation between measured and predicted values. The nuclear design report provides predicted values for target flux difference at various cycle burnups. The difference between the last measured value and the predicted value at the same burnup is applied to the predicted value at the burnup where the target flux difference update is required. This revised predicted value can then be used to determine the updated value of the target flux difference.

SR 3.2.3.5

Measurement of the target flux difference is accomplished by taking a flux map when the core is at equilibrium xenon conditions, preferably at high power levels with the control banks nearly withdrawn. This flux map provides the equilibrium xenon axial power distribution from which the target value can be determined. The target flux difference varies slowly with core burnup.

A Frequency of 31 EFPD after each refueling and 92 EFPD thereafter for remeasuring the target flux differences adjusts the target flux difference to the value measured at steady state conditions. This is the basis for the CAOC. Remeasurement at this Surveillance interval also establishes the AFD target flux difference values that account for changes in incore-excore calibrations that may have occurred in the interim.

This SR is modified by a Note that allows the predicted beginning of cycle AFD from the cycle nuclear design to be used to determine the initial target flux difference after each refueling.

(continued)

BASES (continued)

REFERENCES

1. WCAP-8403 (nonproprietary), "Power Distribution Control and Load Following Procedures," Westinghouse Electric Corporation, September 1974.

2. American National Standard, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," N18.2-1973.

3. UFSAR, Section 7.7.2.6.4.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation. Quadrant Power Tilt is a core tilt that is measured with the use of the excore power range flux detectors. A core tilt is defined as the ratio of maximum to average quadrant power. The QPTR is defined as the ratio of the highest average nuclear power in any quadrant to the average nuclear power in the four quadrants. Limiting the QPTR prevents radial xenon oscillations and will indicate any core asymmetries.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," and LCO 3.1.6, "Control Bank Insertion Limits," provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

APPLICABLE SAFETY ANALYSES

Limits on QPTR preclude core power distributions that violate the following fuel design criteria:

a. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hottest fuel rod in the core does not experience a DNB condition;

b. During a large break loss of coolant accident (LOCA), the peak cladding temperature (PCT) must not exceed 2200°F (Ref. 1);

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. During an ejected rod accident, the energy deposition to the fuel will be below 200 cal/gm (Ref. 2); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), and Bank Insertion, Sequence and Overlap Limits are established to preclude core power distributions that exceed the safety analyses limits.

The QPTR limits ensure that $F^N_{\Delta H}$ and $F_Q(Z)$ remain below their limiting values by preventing an undetected change in the gross radial power distribution.

In MODE 1, the $F^N_{\Delta H}$ and $F_Q(Z)$ limits must be maintained to preclude core power distributions from exceeding design limits assumed in the safety analyses.

The QPTR satisfies Criterion 2 of the NRC Policy Statement.

LCO

The QPTR monitor alarm shall be OPERABLE and QPTR shall be maintained at or below the limit of 1.02.

QPTR is monitored on an automatic basis using the Plant Process Computer System (PPCS) that has a QPTR monitor alarm. The PPCS determines from the excore detector outputs the ratio of the highest average nuclear power in any quadrant to the average of nuclear power in the four quadrants and provides an alarm message if the QPTR is above the 1.02 limit.

The QPTR limit of 1.02, at which corrective action is required, provides a margin of protection for both the DNB ratio and linear heat generation rate contributing to excessive power peaks resulting from X-Y plane power tilts. A limiting QPTR of 1.025 can be tolerated before the margin for uncertainty in $F_Q(Z)$ and $F^N_{\Delta H}$ is possibly challenged. However, the additional QPTR of 0.005 is provided for margin in the LCO.

(continued)

BASES (continued)

APPLICABILITY

The QPTR limit must be maintained in MODE 1 with THERMAL POWER > 50% RTP to prevent core power distributions from exceeding the design limits assumed in the safety analyses.

Applicability in MODE 1 ≤ 50% RTP and in other MODES is not required because there is neither sufficient stored energy in the fuel nor sufficient energy being transferred to the reactor coolant to require the implementation of a QPTR limit on the distribution of core power. The QPTR limit in these conditions is, therefore, not important. Note that the $F^N_{\Delta H}$ and $F_Q(Z)$ LCOs still apply below 50% RTP, but allow progressively higher peaking factors as THERMAL POWER decreases below 50% RTP.

ACTIONS

A.1

With the QPTR exceeding its limit, limiting THERMAL POWER to ≥ 3% below RTP for each 1% by which the QPTR exceeds 1.00 is a conservative tradeoff of total core power with peak linear power. The Completion Time of 2 hours allows sufficient time to identify the cause and correct the tilt. Note that the power reduction itself may cause a change in the tilted condition. A further increase in the QPTR requires a lower limit to THERMAL POWER in accordance with Required Action A.2.

A.2

After completion of Required Action A.1, the QPTR alarm may still be in its alarmed state. As such, any additional changes in the QPTR are detected by requiring a check of the QPTR in accordance with SR 3.2.4.1 once per 12 hours thereafter. If the QPTR continues to increase, THERMAL POWER must be limited accordingly. A 12 hour Completion Time is sufficient because any additional change in QPTR would be relatively slow.

(continued)

BASES

ACTIONS (continued)

A.3

The peaking factors $F^N_{\Delta H}$ and $F_Q(Z)$ are of primary importance in ensuring that the power distribution remains consistent with the initial conditions used in the safety analyses. Performing Srs on $F^N_{\Delta H}$ and $F_Q(Z)$ within the Completion Time of 24 hours ensures that these primary indicators of power distribution are within their respective limits. A Completion Time of 24 hours takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and perform a flux map. If these peaking factors are not within their limits, the Required Actions of these Surveillances provide an appropriate response for the abnormal condition. If the QPTR remains above its specified limit, the peaking factor surveillances are required each 7 days thereafter to evaluate $F^N_{\Delta H}$ and $F_Q(Z)$ with changes in power distribution. Relatively small changes are expected due to either burnup and xenon redistribution or correction of the cause for exceeding the QPTR limit.

A.4

Although $F^N_{\Delta H}$ and $F_Q(Z)$ are of primary importance as initial conditions in the safety analyses, other changes in the power distribution may occur as the QPTR limit is exceeded and may have an impact on the validity of the safety analysis. A change in the power distribution can affect such reactor parameters as bank worths and peaking factors for rod malfunction accidents. When the QPTR exceeds its limit, it does not necessarily mean a safety concern exists. It does mean that there is an indication of a change in the gross radial power distribution that requires an investigation and evaluation that is accomplished by examining the incore power distribution. Specifically, the core peaking factors and the quadrant tilt must be evaluated because they are the factors that best characterize the core power distribution. This re-evaluation is required to ensure that, before increasing THERMAL POWER to above the limit of Required Action A.1, the reactor core conditions are consistent with the assumptions in the safety analyses.

(continued)

BASES

ACTIONS (continued)

A.5

If the QPTR has exceeded the 1.02 limit and the verification of $F^N_{\Delta H}$ and $F_Q(Z)$ shows that safety requirements are met, the excore detectors are normalized to eliminate the indicated tilt prior to increasing THERMAL POWER to above the limit of Required Actions A.1 and A.2. This is done to detect any subsequent significant changes in QPTR and to provide a meaningful QPTR alarm.

Required Action A.5 is modified by a Note that states that the indicated tilt is not eliminated until after the re-evaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). It is necessary to verify that the core power distribution is acceptable prior to adjusting the excore detectors to eliminate the indicated tilt and increasing power to ensure that the plant is not operating in an unanalyzed condition. This Note is intended to prevent any ambiguity about the required sequence of actions.

A.6

After the flux tilt is normalized to eliminate the indicated tilt (i.e., Required Action A.5 is performed), it is acceptable to return to full power operation. However, as an added check that the core power distribution at RTP is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(Z)$ and $F^N_{\Delta H}$ are within their specified limits within 24 hours after reaching RTP. As an added precaution, if the core power does not reach RTP within 24 hours, but it increases slowly, then the peaking factor surveillances must be performed within 24 hours of the time when the ascent to power was begun. These Completion Times are intended to allow adequate time to increase THERMAL POWER to above the limit of Required Actions A.1 and A.2, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

(continued)

BASES

ACTIONS

A.6 (continued)

Required Action A.5 is modified by three Notes. The first Note states that it is not necessary to perform Required Action A.5 if the cause of the QPTR alarm is associated with instrumentation alignment. The intent of this Note is to clarify that the core power distribution does not have to be re-verified if the QPTR alarm is only due to the instrumentation (i.e., the excore detectors) being out of adjustment and not due to an anomaly within the core. The second Note states that the peaking factor surveillances are not required until after the excore detectors have been normalized to eliminate the indicated tilt (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are adjusted to eliminate the indicated tilt and the core returned to power. The third Note states that only one of the following Completion Times, whichever becomes applicable first, must be met. The intent of this Note is to clearly indicate that the first Completion Time to become applicable is the Completion Time which must be met to satisfy Required Action A.6.

B.1

If Required Actions A.1 through A.6 are not completed within their associated Completion Times, the plant must be brought to a MODE or condition in which the requirements do not apply. To achieve this status, THERMAL POWER must be reduced to ≤ 50% RTP within 4 hours. The allowed Completion Time of 4 hours is reasonable, based on operating experience regarding the amount of time required to reach the reduced power level without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

When the QPTR monitor alarm is inoperable the QPTR must be verified within limits at a frequency of every 24 hours to ensure that the plant does not operate in an unanalyzed condition. When THERMAL POWER is ≥ 75% RTP and one power range channel is inoperable, QPTR cannot be adequately measured using the excore detectors. In this situation a flux map must be completed to verify that the core power distribution is consistent with the safety analyses. A Completion Time of 24 hours is adequate to detect any relatively slow changes in QPTR, because for those causes of QPT that occur quickly (e.g., a dropped rod), there typically are other indications of abnormality that prompt a verification of core power tilt and provides sufficient time to stabilize the plant and perform a flux map when necessary. The Completion Time of 24 hours is also consistent with the Frequency of SR 3.2.4.3 with one inoperable power range channel since these channels provide input into the QPTR monitor.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

This SR is the verification that the QPTR monitor is OPERABLE. This is normally accomplished by introducing a signal into the PPCS to verify control room annunciation of QPTR not within limit. The Frequency of 12 hours is sufficient to ensure OPERABILITY of the QPTR monitor since under normal plant operation, QPTR is not expected to significantly change.

SR 3.2.4.2

This Surveillance verifies that the QPTR, as indicated by the Nuclear Instrumentation System (NIS) excore channels, is within its limits. The Frequency of 7 days when the QPTR alarm is OPERABLE is acceptable because of the low probability that this alarm can remain inoperable without detection.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.4.2 (continued)

SR 3.2.4.2 is modified by two Notes. The first allows QPTR to be calculated with three power range channels if THERMAL POWER is < 75% RTP and one power range channel is inoperable. The second Note states that SR 3.2.1.2 and SR 3.2.2.2 should be performed if THERMAL POWER is ≥ 75% RTP and one power range channel is inoperable. The intent of this Note is to clarify that when one power range channel is inoperable and THERMAL POWER is ≥ 75% RTP, a full core flux map should be performed to verify the core power distribution instead of using the three OPERABLE power range channels to verify QPTR. At or above 75% RTP with one power range channel inoperable, QPTR monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. Performing a full core flux map provides an accurate alternative means for ensuring that $F_Q(Z)$ and $F^N_{\Delta H}$ remain within limits and the core power distribution is consistent with the safety analyses.

SR 3.2.4.3

This Surveillance verifies that the QPTR, as indicated by the Nuclear Instrumentation System (NIS) excore channels, is within its limits when the QPTR alarm is inoperable. The Frequency of 24 hours is adequate to detect any relatively slow changes in QPTR, because for those causes of QPT that occur quickly (e.g., a dropped rod), there typically are other indications of abnormality that prompt a verification of core power tilt.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.4.3 (continued)

SR 3.2.4.3 is modified by three Notes. The first Note states that the surveillance is only required to be performed if the QPTR monitor alarm is inoperable. This surveillance requires a more frequent verification that the QPTR is within limit since the monitor alarm is inoperable. The second Note allows QPTR to be calculated with three power range channels if THERMAL POWER is < 75% RTP and one power range channel is inoperable. The third Note states that SR 3.2.1.2 and SR 3.2.2.2 should be performed if THERMAL POWER is ≥ 75% RTP and one power range channel is inoperable. The intent of this Note is clarify that when one power range channel is inoperable and THERMAL POWER is ≥ 75% RTP, a full core flux map should be performed to verify the core power distribution instead of using the three OPERABLE power range channels to verify QPTR. At or above 75% RTP with one power range channel inoperable, QPTR monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. Performing a full core flux map provides an accurate alternative means for ensuring that $F_Q(Z)$ and $F^N_{\Delta H}$ remain within limits and the core power distribution is consistent with the safety analyses.

REFERENCES

1. 10 CFR 50.46.
2. UFSAR, Section 15.4.5.
3. Atomic Industrial Forum (AIF) GDC 29, Issued for comment July 10, 1967.

3.3 INSTRUMENTATION

3.3.1 Reactor Trip System (RTS) Instrumentation

LCO 3.3.1 The RTS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1.

ACTIONS

-----------------------------------NOTE-----------------------------------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel inoperable. <u>OR</u> Two source range channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.1-1 for the channel(s).	Immediately
B. As required by Required Action A.1 and referenced by Table 3.3.1-1.	B.1 Restore channel to OPERABLE status.	48 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time of Condition B not met.	C.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	C.2	Initiate action to fully insert all rods.	6 hours
	<u>AND</u>		
	C.3	Place Control Rod Drive System in a condition incapable of rod withdrawal.	7 hours
D. As required by Required Action A.1 and referenced by Table 3.3.1-1.	D.1	--------NOTE--------- The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. ---------------------	
		Place channel in trip.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. As required by Required Action A.1 and referenced by Table 3.3.1-1.	E.1	Reduce THERMAL POWER to < 5E-11 amps.	2 hours
	<u>OR</u>		
	E.2	---------NOTE-------- Required Action E.2 is not applicable when: a. Two channels are inoperable, or b. THERMAL POWER is < 5E-11 amps. --------------------- Increase THERMAL POWER to ≥ 8% RTP.	2 hours
F. As required by Required Action A.1 and referenced by Table 3.3.1-1.	F.1	Open RTBs and RTBBs upon discovery of two inoperable channels.	Immediately upon discovery of two inoperable channels
	<u>AND</u>		
	F.2	Suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>		
	F.3	Restore channel to OPERABLE status.	48 hours
G. Required Action and associated Completion Time of Condition D, E, or F is not met.	G.1	Be in MODE 3.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
H. As required by Required Action A.1 and referenced by Table 3.3.1-1.	H.1	Restore at least one channel to OPERABLE status upon discovery of two inoperable channels.	1 hour from discovery of two inoperable channels
	<u>AND</u>		
	H.2	Suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>		
	H.3	Restore channel to OPERABLE status.	48 hours
I. Required Action and associated Completion Time of Condition H not met.	I.1	Initiate action to fully insert all rods.	Immediately
	<u>AND</u>		
	I.2	Place the Control Rod Drive System in a condition incapable of rod withdrawal.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
J. As required by Required Action A.1 and referenced by Table 3.3.1-1.	J.1	Suspend operations involving positive reactivity additions.	Immediately
	AND		
	J.2	Perform SR 3.1.1.1.	12 hours AND Once per 12 hours thereafter
K. As required by Required Action A.1 and referenced by Table 3.3.1-1.	K.1	--------NOTE-------- The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. -------------------- Place channel in trip.	6 hours
L. Required Action and associated Completion Time of Condition K not met.	L.1	Reduce THERMAL POWER to < 8.5% RTP.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
M. As required by Required Action A.1 and referenced by Table 3.3.1-1.	M.1	--------NOTE--------- The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. ---------------------	
		Place channel in trip.	6 hours
N. As required by Required Action A.1 and referenced by Table 3.3.1-1.	N.1	Restore channel to OPERABLE status.	6 hours
O. Required Action and associated Completion Time of Condition M or N not met.	O.1	Reduce THERMAL POWER to < 50% RTP.	6 hours
P. As required by Required Action A.1 and referenced by Table 3.3.1-1.	P.1	--------NOTE--------- The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. ---------------------	
		Place channel in trip.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
Q. Required Action and Associated Completion Time of Condition P not met.	Q.1	Reduce THERMAL POWER to < 50% RTP.	6 hours
	AND		
	Q.2.1	Verify Steam Dump System is OPERABLE.	7 hours
		OR	
	Q.2.2	Reduce THERMAL POWER to < 8% RTP.	7 hours
R. As required by Required Action A.1 and referenced by Table 3.3.1-1.	R.1	--------NOTE--------- The inoperable train may be bypassed for up to 4 hours for surveillance testing of the other train. ---------------------	
		Restore train to OPERABLE status.	6 hours
S. As required by Required Action A.1 and referenced by Table 3.3.1-1.	S.1	Verify interlock is in required state for existing plant conditions.	1 hour
	OR		
	S.2	Declare associated RTS Function channel(s) inoperable.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
T. As required by Required Action A.1 and referenced by Table 3.3.1-1.	------------NOTES------------ 1. One train may be bypassed for up to 2 hours for surveillance testing, provided the other train is OPERABLE. 2. One RTB may be bypassed for up to 6 hours for maintenance on undervoltage or shunt trip mechanisms, provided the other train is OPERABLE. ----------------------------	
	T.1 Restore train to OPERABLE status.	1 hour
U. As required by Required Action A.1 and referenced by Table 3.3.1-1.	U.1 Restore at least one trip mechanism to OPERABLE status upon discovery of two RTBs with inoperable trip mechanisms.	1 hour from discovery of two inoperable trip mechanisms
	<u>AND</u>	
	U.2 Restore trip mechanism to OPERABLE status.	48 hours
V. Required Action and associated Completion Time of Condition R, S, T, or U not met.	V.1 Be in MODE 3.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
W. As required by Required Action A.1 and referenced by Table 3.3.1-1.	W.1	Restore at least one trip mechanism to OPERABLE status upon discovery of two RTBs with inoperable trip mechanisms.	1 hour from discovery of two inoperable trip mechanisms
	<u>AND</u>		
	W.2	Restore trip mechanism or train to OPERABLE status.	48 hours
X. Required Action and associated Completion Time of Condition W not met.	X.1	Initiate action to fully insert all rods.	Immediately
	<u>AND</u>		
	X.2	Place the Control Rod Drive System in a Condition incapable of rod withdrawal.	1 hour

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
Refer to Table 3.3.1-1 to determine which SRs apply for each RTS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.2	-------------------NOTE------------------- Required to be performed within 12 hours after THERMAL POWER is ≥ 50% RTP. -- Compare results of calorimetric heat balance calculation to Nuclear Instrumentation System (NIS) channel output and adjust if calorimetric power is > 2% higher than indicated NIS power.	24 hours
SR 3.3.1.3	------------------NOTES------------------ 1. Required to be performed within 7 days after THERMAL POWER is ≥ 50% RTP but prior to exceeding 90% RTP following each refueling and if the Surveillance has not been performed within the last 31 EFPD. 2. Performance of SR 3.3.1.6 satisfies this SR. -- Compare results of the incore detector measurements to NIS AFD and adjust if absolute difference is ≥ 3%.	31 effective full power days (EFPD)

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.4	Perform TADOT.	31 days on a STAGGERED TEST BASIS
SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.1.6	-------------------NOTE------------------- Not required to be performed until 7 days after THERMAL POWER is ≥ 50% RTP, but prior to exceeding 90% RTP following each refueling. -- Calibrate excore channels to agree with incore detector measurements.	92 EFPD
SR 3.3.1.7	-------------------NOTE------------------- Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 4 hours after entering MODE 3. -- Perform COT.	92 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.8	-------------------NOTE------------------- 1. Not required for power range and intermediate range instrumentation until 4 hours after reducing power < 6% RTP. 2. Not required for source range instrumentation until 4 hours after reducing power < 5E-11 amps. -- Perform COT.	92 days
SR 3.3.1.9	-------------------NOTE------------------- Setpoint verification is not required. -- Perform TADOT.	92 days
SR 3.3.1.10	-------------------NOTE------------------- Neutron detectors are excluded. -- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.11	Perform TADOT.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.12	-------------------NOTE------------------- Setpoint verification is not required. --- Perform TADOT.	Prior to reactor startup if not performed within previous 31 days
SR 3.3.1.13	Perform COT.	24 months

Table 3.3.1-1 (page 1 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Manual Reactor Trip	1,2 $3^{(a)}$, $4^{(a)}$, $5^{(a)}$	2	B,C	SR 3.3.1.11	NA
2. Power Range Neutron Flux					
a. High	1,2	4	D,G	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.10	≤ 109% RTP
b. Low	$1^{(b)}$,2	4	D,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.10	≤ 25% RTP
3. Intermediate Range Neutron Flux	$1^{(b)}$, 2	2	E,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.10	(d)
4. Source Range Neutron Flux	$2^{(c)}$	2	F,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.10	(d)
	$3^{(a)}$, $4^{(a)}$, $5^{(a)}$	2	H,I	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	(d)
	$3^{(e)}$, $4^{(e)}$, $5^{(e)}$	1	J	SR 3.3.1.1 SR 3.3.1.10	NA

(continued)

(a) With Control Rod Drive (CRD) System capable of rod withdrawal, or all rods not fully inserted.

(b) THERMAL POWER < 6% RTP.

(c) Both Intermediate Range channels < 5E-11 amps.

(d) UFSAR Table 7.2-3.

(e) With CRD System incapable of withdrawal and all rods fully inserted. In this condition, the Source Range Neutron Flux function does not provide a reactor trip, only indication.

Table 3.3.1-1 (page 2 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
5. Overtemperature ΔT	1,2	4	D,G	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7 SR 3.3.1.10	Refer to Note 1 (page 3.3-18)
6. Overpower ΔT	1,2	4	D,G	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	Refer to Note 2 (page 3.3-19)
7. Pressurizer Pressure					
a. Low	1(f)	4	K,L	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 1865 psig
b. High	1,2	3	D,G	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 2385 psig
8. Pressurizer Water Level —High	1,2	3	D,G	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 88%
9. Reactor Coolant Flow —Low					
a. Single Loop	1(g)	3 per loop	M,O	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 90%
b. Two Loops	1(h)	3 per loop	K,L	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 90%

(continued)

(f) THERMAL POWER ≥ 8.5% RTP.

(g) THERMAL POWER ≥ 50% RTP.

(h) THERMAL POWER ≥ 8.5% RTP and Reactor Coolant Flow —Low (Single Loop) trip Function blocked.

Table 3.3.1-1 (page 3 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
10. Reactor Coolant Pump (RCP) Breaker Position					
a. Single Loop	1(g)	1 per RCP	N,O	SR 3.3.1.11	NA
b. Two Loops	1(i)	1 per RCP	K,L	SR 3.3.1.11	NA
11. Undervoltage – Bus 11A and 11B	1(f)	2 per bus	K,L	SR 3.3.1.9 SR 3.3.1.10	(d)
12. Underfrequency Bus 11A and 11B	1(f)	2 per bus	K,L	SR 3.3.1.9 SR 3.3.1.10	≥ 57.5 HZ
13. Steam Generator (SG) Water Level –Low Low	1,2	3 per SG	D,G	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 16%
14. Turbine Trip					
a. Low Autostop Oil Pressure	1(j)(k)	3	P,Q	SR 3.3.1.10 SR 3.3.1.12	(d)
b. Turbine Stop Valve Closure	1(j)(k)	2	P,Q	SR 3.3.1.12	NA
15. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2	R,V	SR 3.3.1.11	NA

(continued)

(d) UFSAR Table 7.2-3.

(f) THERMAL POWER ≥ 8.5% RTP.

(g) THERMAL POWER ≥ 50% RTP.

(i) THERMAL POWER ≥ 8.5% RTP and RCP Breaker Position (Single Loop) trip Function blocked.

(j) THERMAL POWER > 8% RTP, and either no circulating water pump breakers closed, or condenser vacuum ≤ 20".

(k) THERMAL POWER ≥ 50% RTP, 1 of 2 circulating water pump breakers closed, and condenser vacuum > 20".

Table 3.3.1-1 (page 4 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
16. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	$2^{(c)}$	2	S,V	SR 3.3.1.10 SR 3.3.1.13	≥ 5E-11 amp
b. Low Power Reactor Trips Block, P-7	$1^{(f)}$	4 (power range only)	S,V	SR 3.3.1.10 SR 3.3.1.13	< 8.5% RTP
c. Power Range Neutron Flux, P-8	$1^{(g)}$	4	S,V	SR 3.3.1.10 SR 3.3.1.13	< 50% RTP
d. Power Range Neutron Flux, P-9	$1^{(k)}$	4	S,V	SR 3.3.1.10 SR 3.3.1.13	< 50% RTP
	$1^{(j)}$	4	S,V	SR 3.3.1.10 SR 3.3.1.13	≤ 8% RTP
e. Power Range Neutron Flux, P-10	$1^{(b)}$,2	4	S,V	SR 3.3.1.10 SR 3.3.1.13	≥ 6% RTP
17. Reactor Trip Breakers$^{(l)}$	1,2	2 trains	T,V	SR 3.3.1.4	NA
	$3^{(a)}$, $4^{(a)}$, $5^{(a)}$	2 trains	W,X	SR 3.3.1.4	NA
18. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1,2	1 each per RTB	U,V	SR 3.3.1.4	NA
	$3^{(a)}$, $4^{(a)}$, $5^{(a)}$	1 each per RTB	W,X	SR 3.3.1.4	NA
19. Automatic Trip Logic	1,2	2 trains	R,V	SR 3.3.1.5	NA
	$3^{(a)}$, $4^{(a)}$, $5^{(a)}$	2 trains	W,X	SR 3.3.1.5	NA

(a) With CRD System capable of rod withdrawal or all rods not fully inserted.

(b) THERMAL POWER < 6% RTP.

(c) Both Intermediate Range channels < 5E-11 amps.

(f) THERMAL POWER ≥ 8.5% RTP.

(g) THERMAL POWER ≥ 50% RTP.

(j) THERMAL POWER > 8% RTP, and either no circulating water pump breakers closed, or condenser vacuum ≤ 20".

(k) THERMAL POWER ≥ 50% RTP, 1 of 2 circulating water pump breakers closed, and condenser vacuum > 20".

(l) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.1-1 (page 5 of 6)
Reactor Trip System Instrumentation

Note 1: Overtemperature ΔT

The Overtemperature ΔT Function Trip Setpoint is defined by:

$$\text{Overtemperature } \Delta T \leq \Delta T_o \left\{ K_1 + K_2 (P - P') - K_3 (T - T') \left[\frac{1 + \tau_1 s}{1 + \tau_2 s}\right] - f(\Delta I) \right\}$$

Where:

ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.

s is the Laplace transform operator, sec^{-1}.

T is the measured RCS average temperature, °F.
T' is the nominal T_{avg} at RTP, °F.

P is the measured pressurizer pressure, psig.
P' is the nominal RCS operating pressure, psig.

K_1 is the Overtemperature ΔT reactor trip setpoint, 1.20.
K_2 is the Overtemperature ΔT reactor trip depressurization setpoint penalty coefficient, 0.000900.
K_3 is the Overtemperature ΔT reactor trip heatup setpoint penalty coefficient, 0.0209.

τ_1 is the measured lead/lag time constant, 25 seconds.

τ_2 is the measured lead/lag time constant, 5 seconds.

$f(\Delta I)$ is a function of the indicated difference between the top and bottom detectors of the Power Range Neutron Flux channels where q_t and q_b are the percent power in the top and bottom halves of the core, respectively, and $q_t + Q_b$ is the total THERMAL POWER in percent RTP.

$f(\Delta I) = 0$ when $q_t - q_b$ is > +13% RTP

$f(\Delta I) = 1.3 \{(q_t - q_b) - 13\}$ when $q_t - q_b$ is > +13% RTP

Table 3.3.1-1 (page 6 of 6)
Reactor Trip System Instrumentation

Note 2: Overpower ΔT

The Overpower ΔT Function Trip Setpoint is defined by:

$$\text{Overpower } \Delta T \leq \Delta T_0 \left\{ K_4 - K_5 (T - T') - K_6 \left[\frac{\tau_3 s T}{\tau_3 s + 1} \right] - f(\Delta I) \right\}$$

Where:

ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.

s is the Laplace transform operator, sec^{-1}.

T is the measured RCS average temperature, °F.
T′ is the nominal T_{avg} at RTP, °F.

K_4 is the Overpower ΔT reactor trip setpoint, 1.077.
K_5 is the Overpower ΔT reactor trip heatup setpoint penalty coefficient which is:
0.0 for $T < T^2$ and;
0.0011 for $T \geq T^2$.
K_6 is the Overpower ΔT reactor trip thermal time delay setpoint penalty which is:
0.0262 for increasing T and;
0.00 for decreasing T.

τ_3 is the measured lead/lag time constant, 10 seconds.

$f(\Delta I)$ is a function of the indicated difference between the top and bottom detectors of the Power Range Neutron Flux channels where q_t and q_b are the percent power in the top and bottom halves of the core, respectively, and $q_t + q_b$ is the total THERMAL POWER in percent RTP.

$f(\Delta I) = 0$	when $q_t - q_b$ is > +13% RTP
$f(\Delta I) = 1.3 \{(q_t - q_b) - 13\}$	when $q_t - q_b$ is > +13% RTP

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1.

ACTIONS

-----------------------------------NOTE-----------------------------------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel or train inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel or train.	Immediately
B. As required by Required Action A.1 and referenced by Table 3.3.2-1.	B.1 Restore channel to OPERABLE status.	48 hours
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3.	6 hours

(continued

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. As required by Required Action A.1 and referenced by Table 3.3.2-1.	D.1	Restore channel to OPERABLE status.	48 hours
E. As required by Required Action A.1 and referenced by Table 3.3.2-1.	E.1	Restore train to OPERABLE status.	6 hours
F. As required by Required Action A.1 and referenced by Table 3.3.2-1.	F.1	-------NOTE-------- The inoperable channel may be bypassed for up to 4 hours for surveillance testing of the other channels. -------------------- Place channel in trip.	6 hours
G. Required Action and associated Completion Time of Condition D, E, or F not met.	G.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	G.2	Be in MODE 4.	12 hours
H. As required by Required Action A.1 and referenced by Table 3.3.2-1.	H.1	Restore channel to OPERABLE status.	48 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
I. As required by Required Action A.1 and referenced by Table 3.3.2-1.	I.1	Restore train to OPERABLE status.	6 hours
J. As required by Required Action A.1 and referenced by Table 3.3.2-1.	J.1	--------NOTE--------- The inoperable channel may be bypassed for up to 4 hours for surveillance testing of the other channels. ---------------------	
		Place channel in trip.	6 hours
K. Required Action and associated Completion Time of Condition H, I, or J not met.	K.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	K.2	Be in MODE 5.	36 hours
L. As required by Required Action A.1 and referenced by Table 3.3.2-1.	L.1	--------NOTE--------- The inoperable channel may be bypassed for up to 4 hours for surveillance testing of the other channels. ---------------------	
		Place channel in trip.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
M. Required Action and associated Completion Time of Condition L not met.	M.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	M.2	Reduce pressurizer pressure to < 2000 psig.	12 hours
N. As required by Required Action A.1 and referenced by Table 3.3.2-1.	N.1	Declare associated Auxiliary Feedwater pump inoperable and enter applicable condition(s) of LCO 3.7.5, "Auxiliary Feedwater (AFW) System."	Immediately

SURVEILLANCE REQUIREMENTS

------------------------------------NOTES------------------------------------

1. Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

	SURVEILLANCE	FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform COT.	92 days
SR 3.3.2.3	-------------------NOTE------------------ Verification of relay setpoints not required. --- Perform TADOT.	92 days
SR 3.3.2.4	-------------------NOTE------------------ Verification of relay setpoints not required. --- Perform TADOT.	24 months
SR 3.3.2.5	Perform CHANNEL CALIBRATION.	24 months
SR 3.3.2.6	Verify the Pressurizer Pressure – Low and Steam Line Pressure – Low Functions are not bypassed when pressurizer pressure > 2000 psig.	24 months
SR 3.3.2.7	Perform ACTUATION LOGIC TEST.	24 months

Table 3.3.2-1 (page 1 of 3)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
1. Safety Injection						
a. Manual Initiation	1,2,3	2	D,G	SR 3.3.2.4	NA	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	I,K	SR 3.3.2.7	NA	NA
c. Containment Pressure —High	1,2,3,4	3	J,K	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 6.0 psig	≤ 4.0 psig
d. Pressurizer Pressure —Low	1,2,3(a)	3	L,M	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5 SR 3.3.2.6	≥ 1715 psig	≥ 1750 psig
e. Steam Line Pressure —Low	1,2,3(a)	3 per steam line	L,M	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5 SR 3.3.2.6	≥ 358 psig	≥ 514 psig
2. Containment Spray						
a. Manual Initiation						
Left pushbutton	1,2,3,4	1	H,K	SR 3.3.2.4	NA	NA
Right pushbutton	1,2,3,4	1	H,K	SR 3.3.2.4	NA	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	I,K	SR 3.3.2.7	NA	NA
c. Containment Pressure —High High	1,2,3,4	3 per set	J,K	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 32.5 psig	≤ 28 psig
3. Containment Isolation						
a. Manual Initiation	1,2,3,4	2	H,K	SR 3.3.2.4	NA	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	I,K	SR 3.3.2.7	NA	NA
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					

(continued)

(a) Pressurizer Pressure ≥ 2000 psig.

Table 3.3.2-1 (page 2 of 3)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
4. Steam Line Isolation						
a. Manual Initiation	1,2(b),3(b)	1 per loop	D,G	SR 3.3.2.4	NA	NA
b. Automatic Actuation Logic and Actuation Relays	1,2(b),3(b)	2 trains	E,G	SR 3.3.2.7	NA	NA
c. Containment Pressure — High High	1,2(b),3(b)	3	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 20 psig	≤ 18 psig
d. High Steam Flow	1,2(b),3(b)	2 per steam line	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 0.55E6 lbm/hr @ 755 psi	≤ 0.4E6 lbm/hr @ 755 psig
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
and						
Coincident with T_{avg} — Low	1,2(b),3(b)	2 per loop	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≥ 543°F	≥ 545°F
e. High — High Steam Flow	1,2(b),3(b)	2 per steam line	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 3.7E6 lbm/hr @ 755 psig	≤ 3.6E6 lbm/hr @ 755 psig
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					

(continued)

(b) Except when both MSIVs are closed and de-activated.

Table 3.3.2-1 (page 3 of 3)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
5. Feedwater Isolation						
a. Automatic Actuation Logic and Actuation Relays	1,2(c),3(c)	2 trains	E,G	SR 3.3.2.7	NA	NA
b. SG Water Level —High	1,2(c),3(c)	3 per SG	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 68%	≤ 67%
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
6. Auxiliary Feedwater (AFW)						
a. Manual Initiation						
AFW	1,2,3	1 per pump	N	SR 3.3.2.4	NA	NA
Standby AFW	1,2,3	1 per pump	N	SR 3.3.2.4	NA	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	E,G	SR 3.3.2.7	NA	NA
c. SG Water Level —Low Low	1,2,3	3 per SG	D,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≥ 16%	≥ 17%
d. Safety Injection (Motor driven pumps only)	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
e. Undervoltage —Bus 11A and 11B (Turbine driven pump only)	1,2,3	2 per bus	D,G	SR 3.3.2.3 SR 3.3.2.5	≥ 2450 V with ≤ 3.6 sec time delay	≥ 2579 V with ≤ 3.6 sec time delay
f. Trip of Both Main Feedwater Pumps (Motor driven pumps only)	1,2	2 per MFW pump	B,C	SR 3.3.2.4	NA	NA

(c) Except when all Main Feedwater Regulating and associated bypass valves are closed and de-activated or isolated by a closed manual valve.

3.3 INSTRUMENTATION

3.3.3 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3 The PAM instrumentation for each Function in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

------------------------------------NOTES------------------------------------

1. LCO 3.0.4 is not applicable.

2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ---------NOTE--------- Not applicable to Functions 3 and 4. -------------------- One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action to prepare and submit a special report.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. ---------NOTE--------- Only applicable to Functions 3 and 4. --------------------- One or more Functions with required channel inoperable.	C.1	Restore required channel to OPERABLE status.	7 days
D. ---------NOTE--------- Not applicable to Function 11. --------------------- One or more Functions with two required channels inoperable.	D.1	Restore one channel to OPERABLE status.	7 days
E. Two hydrogen monitor channels inoperable.	E.1	Restore one hydrogen monitor channel to OPERABLE status.	72 hours
F. Required Action and associated Completion Time of Condition C, D, or E not met.	F.1	Enter the Condition referenced in Table 3.3.3-1 for the channel.	Immediately
G. As required by Required Action F.1 and referenced in Table 3.3.3-1.	G.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	G.2	Be in MODE 4.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. As required by Required Action F.1 and referenced in Table 3.3.3-1.	H.1 Initiate action to prepare and submit a special report.	Immediately

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.3.2	Perform CHANNEL CALIBRATION.	24 months

Table 3.3.3-1 (page 1 of 2)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS	CONDITION
1.	Pressurizer Pressure	2	G
2.	Pressurizer Level	2	G
3.	Reactor Coolant System (RCS) Hot Leg Temperature	1 per loop	G
4.	RCS Cold Leg Temperature	1 per loop	G
5.	RCS Pressure (Wide Range)	2	G
6.	RCS Subcooling Monitor	2	G
7.	Reactor Vessel Water Level	2	H
8.	Containment Sump B Water Level	2	G
9.	Containment Pressure (Wide Range)	2	G
10.	Containment Area Radiation (High Range)	2	H
11.	Hydrogen Monitors	2	G
12.	Condensate Storage Tank Level	2	G
13.	Refueling Water Storage Tank Level	2	G
14.	Residual Heat Removal Flow	2	G
15.	Core Exit Temperature – Quadrant 1	2[a]	G
16.	Core Exit Temperature – Quadrant 2	2[a]	G
17.	Core Exit Temperature – Quadrant 3	2[a]	G
18.	Core Exit Temperature – Quadrant 4	2[a]	G
19.	Auxiliary Feedwater (AFW) Flow to Steam Generator (SG) A	2	G
20.	AFW Flow to SG B	2	G
21.	SG Water Level (Narrow Range) to SG A	2	G
22.	SG Water Level (Narrow Range) to SG B	2	G

(continued)

(a) A channel consists of two core exit thermocouples (CETs).

Table 3.3.3-1 (page 2 of 2)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS	CONDITION
23.	SG Water Level (Wide Range) to SG A	2	G
24.	SG Water Level (Wide Range) to SG B	2	G
25.	SG Pressure to SG A	2	G
26.	SG Pressure to SG B	2	G

3.3 INSTRUMENTATION

3.3.4 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

LCO 3.3.4 Each 480 V safeguards bus shall have two OPERABLE channels of LOP DG Start Instrumentation.

APPLICABILITY: MODES 1, 2, 3, and 4,
When associated DG is required to be OPERABLE by LCO 3.8.2, "AC Sources—MODES 5 and 6."

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each 480 V safeguards bus.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more 480 V bus(es) with one channel inoperable.	A.1 Place channel(s) in trip.	6 hours
B. Required Action and associated Completion Time of Condition A not met. OR One or more 480 V bus(es) with two channels inoperable.	B.1 Enter applicable Condition(s) and Required Action(s) for the associated DG made inoperable by LOP DG start instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

-------------------------------------NOTE-------------------------------------
When a channel is placed in an inoperable status solely for the performance of required Surveillances, entry into the associated Conditions and Required Actions may be delayed for up to 4 hours provided the second channel maintains LOP DG start capability.

SURVEILLANCE		FREQUENCY
SR 3.3.4.1	Perform TADOT.	31 days
SR 3.3.4.2	Perform CHANNEL CALIBRATION with Trip Setpoint and Allowable Value for each 480 V bus as follows: a. Loss of voltage: Allowable Value / Trip Setpoint Bus voltage ≥ 368 V / ≥ 372.8 V Time delay ≤ 2.75 sec / 2.4 ± 0.12 sec b. Degraded voltage: Allowable Value / Trip Setpoint Bus voltage ≥ 414 V / ≥ 419.2 V Time delay ≤ 1520 sec / ≤ 1520 sec	24 months

3.3 INSTRUMENTATION

3.3.5 Containment Ventilation Isolation Instrumentation

LCO 3.3.5 The Containment Ventilation Isolation instrumentation for each Function in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4,
During CORE ALTERATIONS,
During movement of irradiated fuel assemblies within containment.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One radiation monitoring channel inoperable.	A.1 Restore the affected channel to OPERABLE status.	4 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. ---------NOTE--------- Only applicable in MODE 1, 2, 3, or 4. ---------------------- One or more Functions with one or more manual or automatic actuation trains inoperable. <u>OR</u> Both radiation monitoring channels inoperable. <u>OR</u> Required Action and associated Completion Time of Condition A not met.	B.1 Enter applicable Conditions and Required Actions of LCO 3.6.3, "Containment Isolation Boundaries," for containment mini-purge isolation valves made inoperable by isolation instrumentation.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. ---------NOTE--------- Only applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. ---------------------- One or more Functions with one or more manual or automatic actuation trains inoperable. OR Both radiation monitoring channels inoperable. OR Required Action and associated Completion Time for Condition A not met.	C.1	Place and maintain containment purge and exhaust valves in closed position.	Immediately
	OR		
	C.2	Enter applicable Conditions and Required Actions of LCO 3.9.3, "Containment Penetrations," for containment purge and exhaust isolation valves made inoperable by isolation instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

-----------------------------------NOTE-----------------------------------
Refer to Table 3.3.5-1 to determine which SRs apply for each Containment Ventilation Isolation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	Perform CHANNEL CHECK.	24 hours
SR 3.3.5.2	Perform COT.	92 days
SR 3.3.5.3	Perform ACTUATION LOGIC TEST.	24 months
SR 3.3.5.4	Perform CHANNEL CALIBRATION.	24 months

Table 3.3.5-1 (page 1 of 1)
Containment Ventilation Isolation Instrumentation

FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Automatic Actuation Logic and Actuation Relays	2 trains	SR 3.3.5.3	NA
2. Containment Radiation			
a. Gaseous	1	SR 3.3.5.1 SR 3.3.5.2 SR 3.3.5.4	(a)
b. Particulate	1	SR 3.3.5.1 SR 3.3.5.2 SR 3.3.5.4	(a)
3. Containment Isolation	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 3, for all initiation functions and requirements.		
4. Containment Spray —Manual Isolation	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 2.a, for all initiation functions and requirements.		

Notes:

(a) Per Radiological Effluent Controls Program.

3.3 INSTRUMENTATION

3.3.6 Control Room Emergency Air Treatment System (CREATS) Actuation Instrumentation

LCO 3.3.6 The CREATS actuation instrumentation for each Function in Table 3.3.6-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, 4, 5, and 6,
During movement of irradiated fuel assemblies.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more Functions with one channel inoperable.	A.1	--------NOTE-------- The control room may be unisolated for ≤ 1 hour every 24 hours while in this condition. ------------------- Place CREATS in Mode F.	 1 hour
B. Required Action and associated Completion Time of Condition A not met in MODE 1, 2, 3, or 4.	B.1 AND B.2	Be in MODE 3. Be in MODE 5.	6 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time of Condition A not met in MODE 5 or 6, or during movement of irradiated fuel assemblies.	C.1	Initiate action to restore channel(s) to OPERABLE status.	Immediately
	<u>AND</u>		
	C.2	Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>		
	C.3	Suspend movement of irradiated fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

-----------------------------------NOTE-----------------------------------
Refer to Table 3.3.6-1 to determine which SRs apply for each CREATS Actuation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1	Perform COT.	92 days
SR 3.3.6.2	-------------------NOTE------------------ Verification of setpoint is not required. --- Perform TADOT.	24 months
SR 3.3.6.3	Perform CHANNEL CALIBRATION.	24 months
SR 3.3.6.4	Perform ACTUATION LOGIC TEST.	24 months

Table 3.3.6-1 (page 1 of 1)
CREATS Actuation Instrumentation

FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Manual Initiation	1 train	SR 3.3.6.2	NA
2. Automatic Actuation Logic and Actuation Relays	1 train	SR 3.3.6.4	NA
3. Control Room Radiation Intake Monitor			
a. Iodine	1	SR 3.3.6.1 SR 3.3.6.3	$\leq 9 \times 10^{-9}$ μCi/cc
b. Noble Gas	1	SR 3.3.6.1 SR 3.3.6.3	$\leq 1 \times 10^{-5}$ μCi/cc
c. Particulate	1	SR 3.3.6.1 SR 3.3.6.3	$\leq 1 \times 10^{-8}$ μCi/cc

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Trip System (RTS) Instrumentation

BASES

BACKGROUND

Atomic Industry Forum (AIF) GDC 14 (Ref. 1) requires that the core protection systems, together with associated engineered safety features equipment, be designed to prevent or suppress conditions that could result in exceeding acceptable fuel design limits. The RTS initiates a plant shutdown, based on the values of selected plant parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The installed protection and monitoring systems have been designed to assure safe operation of the reactor at all times. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RTS, as well as specifying LCOs with respect to these parameters and other reactor system parameters and equipment.

The LSSS, defined in this specification as the Trip Setpoints, in conjunction with the associated LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits during Design Basis Accidents (DBAs). These acceptable limits are:

a. The Safety Limit (SL) values shall be maintained to prevent departure from nucleate boiling (DNB);

b. Fuel centerline melt shall not occur; and

c. The RCS pressure SL of 2735 psig shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," maintains the above values and assures that offsite dose will be within 10 CFR 100 limits (Ref. 2) during AOOs.

(continued)

BASES

BACKGROUND (continued)

DBAs are events that are analyzed even though they are not expected to occur during the plant life. The DBA acceptance limit is that offsite doses shall be maintained within an acceptable fraction of 10 CFR 100 limits (Ref. 2). There are five different accident categories which are organized based on the probability of occurrence (Ref. 3). Each accident category is allowed a different fraction of the 10 CFR 100 limits, inversely proportioned to the probability of occurrence. Meeting the acceptable dose limit for an accident category is considered as having acceptable consequences for that event.

The RTS instrumentation is segmented into three distinct but interconnected modules as described in UFSAR, Chapter 7 (Ref. 4):

a. Field transmitters or process sensors;

b. Signal process control and protection equipment; and

c. Reactor trip switchgear.

These modules are shown in Figure B 3.3.1-1 and discussed in more detail below.

Field Transmitters and Process Sensors

Field transmitters and process sensors provide a measurable electronic signal based on the physical characteristics of the parameter being measured. To meet the design demands for redundancy and reliability, two, three, and up to four field transmitters or sensors are used to measure required plant parameters. To account for the calibration tolerances and instrument drift, which is assumed to occur between calibrations, statistical allowances are provided. These statistical allowances provide the basis for determining acceptable "as left" and "as found" calibration values for each transmitter or sensor as provided in established plant procedures.

(continued)

BASES

BACKGROUND (continued)

Signal Process Control and Protection Equipment

The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. These setpoints are defined in UFSAR, Chapter 7 (Ref. 4), Chapter 6 (Ref. 5), and Chapter 15 (Ref. 6). If the measured value of a plant parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the logic relays.

Generally, three or four channels of process control equipment are used for the signal processing of plant parameters measured by the field transmitters and sensors. If a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are typically sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function can still be accomplished with a two-out-of-two logic. If one channel fails in a direction that a partial Function trip occurs, a trip will not occur unless a second channel fails or trips in the remaining one-out-of-two logic.

If a parameter has no measurable setpoint and is only used as an input to the protection circuits (e.g., manual trip functions) two channels with a one-out-of-two logic are sufficient. A third channel is not required since no surveillance testing is required during the time period in which the parameter is required.

If a parameter is used for input to the protection system and a control function, four channels with a two-out-of-four logic are typically sufficient to provide the required reliability and redundancy. This ensures that the circuit is able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Therefore, a single failure will neither cause nor prevent the protection function actuation. These requirements are described in IEEE-279-1971 (Ref. 7).

(continued)

BASES

BACKGROUND

Signal Process Control and Protection Equipment (continued)

The two, three, and four process control channels discussed above all feed two logic trains. Figure B 3.3.1-1 shows a two-out-of-four logic function which provides input into two logic trains (Train A and B). Two logic trains are required to ensure that no single failure of one logic train will disable the RTS. Provisions to allow removing logic trains from service during maintenance are unnecessary because of the logic system's designed reliability. During normal operation, the two logic trains remain energized.

Reactor Trip Switchgear

The reactor trip switchgear includes the reactor trip breakers (RTBs) and bypass breakers as shown on Figure B 3.3.1-1. The RTBs are in the electrical power supply line from the control rod drive motor generator set power supply to the control rod drive mechanisms (CRDMs). Opening of the RTBs interrupts power to the CRDMs, which allows the shutdown rods and control rods to fall into the core by gravity and shutdown the reactor. Each RTB may be bypassed with a bypass breaker to allow testing of the RTB while the plant is at power. During normal operation, the output from the protection system is a voltage signal that energizes the undervoltage coils in the RTBs and bypass breakers, if in use. When the required logic matrix combination is completed, the protection system output voltage signal is removed, the undervoltage coils are de-energized, the breaker trip lever is actuated by the de-energized undervoltage coil, and the RTBs and bypass breakers are tripped open allowing the shutdown rods and control rods to fall into the core. Therefore, a loss of power to the protection system or RTBs will cause a reactor trip. In addition to the de-energization of the undervoltage coils, each breaker is also equipped with a shunt trip device that is energized to trip the breaker open upon receipt of a reactor trip signal from the protection system (except for the zirconium guide tube trip which only utilizes the undervoltage coils). Either the undervoltage coil or the shunt trip mechanism is sufficient by itself to open the RTBs, thus providing diverse trip mechanisms.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RTS functions to maintain the SLs during all AOOs and mitigates the consequences of DBAs which initiate in any MODE in which the RTBs are closed.

Each of the analyzed accidents and transients can be detected by one or more RTS Functions. The accident analysis described in Reference 6 takes credit for most RTS trip Functions. RTS trip Functions not specifically credited in the accident analysis are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the plant. These RTS trip Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. They may also serve as anticipatory trips to RTS trip Functions that were credited in the accident analysis.

The LCO requires all instrumentation performing an RTS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of three or four channels in each instrumentation Function, two channels of Manual Reactor Trip in each logic Function, and two trains in each Automatic Trip Logic Function. Four OPERABLE instrumentation channels in a two-out-of-four configuration are required when one RTS channel is also used as a control system input. This configuration accounts for the possibility of the shared channel failing in such a manner that it creates a transient that requires RTS action. In this case, the RTS will still provide protection, even with random failure of one of the other three protection channels. Three operable instrumentation channels in a two-out-of-three configuration are generally required when there is no potential for control system and protection system interaction that could simultaneously create a need for a RTS trip and disable one RTS channel. The two-out-of-three and two-out-of-four configurations allow one channel to be tripped or bypassed during maintenance or testing without causing a reactor trip. Specific exceptions to the above general philosophy exist and are discussed below.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

The LCO and Applicability of each RTS Function are provided in Table 3.3.1-1. Included on Table 3.3.1-1 are Trip Setpoints for all applicable RTS Functions. Trip Setpoints for RTS Functions not specifically modeled in the safety analysis are based on established limits provided in the UFSAR (Reference 4). Note that in the accompanying LCO 3.3.1, the Trip Setpoints of Table 3.3.1-1 are the LSSS. The Trip Setpoints are the limiting values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the allowable tolerance band for CHANNEL CALIBRATION accuracy as specified within plant procedures. The channel containing the bistable is considered inoperable when the "as found" value exceeds the Trip Setpoint specified in Table 3.3.1-1.

The Trip Setpoints used in the bistables are based on the analytical limits stated in References 4, 5, and 6. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays, calibration tolerances, instrumentation uncertainties, and instrument drift are taken into account. The Trip Setpoints specified in Table 3.3.1-1 are therefore conservatively adjusted with respect to the analytical limits used in the accident analysis. A detailed description of the methodology used to verify the adequacy of the existing Trip Setpoints, including their explicit uncertainties, is provided in Reference 8.

The RTS utilizes various permissive signals to ensure reactor trip Functions are in the correct configuration for the current plant status. These permissives back up operator actions to ensure protection system Functions are not bypassed during plant conditions under which the safety analysis assumes the Function is available.

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY (continued)

The safety analyses and OPERABILITY requirements applicable to each RTS Function and permissive provided in Table 3.3.1-1 are discussed below:

1. <u>Manual Reactor Trip</u>

The Manual Reactor Trip Function ensures that the control room operator can initiate a reactor trip at any time by using either of two reactor trip pushbuttons on the main control board. A Manual Reactor Trip energizes the shunt trip device and de-energizes the undervoltage coils for the RTBs and bypass breakers. It is used at the discretion of the control room operators to shut down the reactor whenever any parameter is rapidly trending toward its Trip Setpoint or during other degrading plant conditions.

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip pushbutton which actuates the reactor trip breaker in both trains. Two independent channels are required to be OPERABLE so that no single failure will disable the Manual Reactor Trip Function. This function has no adjustable trip setpoint with which to associate an LSSS, therefore no setpoints are provided.

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

1. Manual Reactor Trip (continued)

In MODE 1 or 2, manual initiation capability of a reactor trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the manual initiation Function must also be OPERABLE if the RTBs are closed and the Control Rod Drive (CRD) System is capable of withdrawing the shutdown rods or the control rods. In this condition, inadvertent control rod withdrawal is possible. In MODE 3, 4, or 5, manual initiation of a reactor trip is not required to be OPERABLE if the CRD System is not capable of withdrawing the shutdown rods or control rods, or if one or more RTBs are open. If the rods cannot be withdrawn from the core, there is no need to be able to trip the reactor because all of the rods are inserted. In MODE 6, neither the shutdown rods nor the control rods are permitted to be withdrawn and the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function is not required.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. Power Range Neutron Flux

The Power Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident. The Nuclear Instrumentation System (NIS) power range detectors (N-41, N-42, N-43, and N-44) are located external to the reactor vessel and measure neutrons leaking from the core. The NIS power range detectors provide input to the CRD System for determination of automatic rod speed and direction. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation.

a. Power Range Neutron Flux-High

The Power Range Neutron Flux-High trip Function ensures that protection is provided, from all power levels, against a positive reactivity excursion leading to DNB during power operations. These reactivity excursions can be caused by rod withdrawal or reductions in RCS temperature. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

The LCO requires all four of the Power Range Neutron Flux-High trip Function channels to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Power Range Neutron Flux - High (continued)

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux - High trip must be OPERABLE. This Function will terminate the reactivity excursion and shut down the reactor prior to reaching a power level that could damage the fuel. In MODE 3, 4, 5, or 6, the NIS power range detectors cannot detect neutron levels in this range. In these MODES, the Power Range Neutron Flux - High trip Function is not required to be OPERABLE because the reactor is shut down and reactivity excursions into the power range are extremely unlikely. Other RTS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

b. Power Range Neutron Flux - Low

The LCO requirement for the Power Range Neutron Flux - Low trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions.

The LCO requires all four of the Power Range Neutron Flux - Low trip Function channels (N-41, N-42, N-43, and N-44) to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Power Range Neutron Flux - Low (continued)

In MODE 1, below 6% RTP, and in MODE 2, the Power Range Neutron Flux - Low trip must be OPERABLE. This Function may be manually blocked by the operator when two-out-of-four power range channels are greater than approximately 8% RTP (P-10 setpoint). This Function is automatically unblocked when three-out-of-four power range channels are below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the Power Range Neutron Flux - High trip Function.

In MODE 3, 4, 5, or 6, the Power Range Neutron Flux - Low trip Function is not required to be OPERABLE because the reactor is shut down and the NIS power range detectors cannot detect neutron levels in this range. Other RTS trip Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

3. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition. This trip Function provides redundant protection to the Power Range Neutron Flux - Low trip Function and is not specifically modeled in the accident analysis. The NIS intermediate range detectors (N-35 and N-36) are located external to the reactor vessel and measure neutrons leaking from the core. The NIS intermediate range detectors do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Intermediate Range Neutron Flux (continued)

The LCO requires two channels of the Intermediate Range Neutron Flux trip Function to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single failure will disable this trip Function. Because this trip Function is important only during low power conditions, there is generally no need to disable channels for testing while the Function is required to be OPERABLE. Therefore, a third channel is unnecessary.

In MODE 1 below 6% RTP, and in MODE 2, the Intermediate Range Neutron Flux trip Function must be OPERABLE since there is a potential for an uncontrolled RCCA bank rod withdrawal accident. Above 8% RTP (P-10 setpoint), the Power Range Neutron Flux—High trip provides core protection for a rod withdrawal accident. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip Function is not required to be OPERABLE because the NIS intermediate range detectors cannot detect neutron levels in this range. Other RTS trip Functions and administrative controls provide protection against reactivity additions or power excursions in MODE 3, 4, 5, or 6.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4. Source Range Neutron Flux

The LCO requirement for the Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition and provides protection against boron dilution and rod ejection events. This trip Function provides redundant protection to the Power Range Neutron Flux—Low and Intermediate Range Neutron Flux trip Functions in MODE 2 and is not specifically credited in the accident analysis at these conditions. The NIS source range detectors (N-31 and N-32) are located external to the reactor vessel and measure neutrons leaking from the core. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RTS automatic protection function required in MODES 3, 4, and 5. Therefore, the functional capability at the specified Trip Setpoint is assumed to be available.

The LCO requires two channels of Source Range Neutron Flux trip Function to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single failure will disable this trip Function. The LCO also requires one channel of the Source Range Neutron Flux trip Function to be OPERABLE in MODE 3, 4, or 5 with the CRD System not capable of rod withdrawal and all rods fully inserted. In this case, the source range Function is to provide control room indication. The outputs of the Function to RTS logic are not required to be OPERABLE when the CRD system is not capable of rod withdrawal and all rods fully inserted.

The Source Range Neutron Flux Trip Function provides protection for control rod withdrawal from subcritical, boron dilution and control rod ejection events. The Function also provides visual neutron flux indication in the control room.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Source Range Neutron Flux (continued)

In MODE 2 when both intermediate range channels are < 5E-11 amps (below the P-6 setpoint), the Source Range Neutron Flux trip Function must be OPERABLE. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux—Low trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the NIS source range detectors are manually de-energized by the operator and are inoperable.

In MODE 3, 4, or 5 with the CRD System capable of rod withdrawal or all rods are not fully inserted, the Source Range Neutron Flux trip Function must be OPERABLE to provide core protection against a rod withdrawal accident. If the CRD System is not capable of rod withdrawal and all rods are fully inserted, the source range detectors are not required to trip the reactor. However, their monitoring Function must be OPERABLE to monitor core neutron levels and provide indication of reactivity changes that may occur as a result of events like a boron dilution. The requirements for the NIS source range detectors in MODE 6 are addressed in LCO 3.9.2, "Nuclear Instrumentation."

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. Overtemperature ΔT

The Overtemperature ΔT trip Function is provided to ensure that the design limit departure from nucleate boiling ratio (DNBR) is met. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include pressure, T_{avg}, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system. The Overtemperature ΔT trip Function monitors both variation in power and flow since a decrease in flow has the same effect on ΔT as a power increase. The Overtemperature ΔT trip Function uses the ΔT of each loop as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature – the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;

- pressurizer pressure – the Trip Setpoint is varied to correct for changes in system pressure; and

- axial power distribution $f(\Delta I)$ – the Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the design limit, as indicated by the difference between the upper and lower NIS power range detectors, the Trip Setpoint is reduced in accordance with Note 1 of Table 3.3.1-1.

Dynamic compensation is included for system piping delays from the core to the temperature measurement system.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Overtemperature ΔT (continued)

The Overtemperature ΔT trip Function is calculated in two channels for each loop as described in Note 1 of Table 3.3.1-1. A reactor trip occurs if the Overtemperature ΔT Trip Setpoint is reached in two-out-of-four channels. Since the pressure and temperature signals are used for other control functions, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Section 7.2.5 of Reference 4 discusses control and protection system interactions for this function. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent an unnecessary reactor trip.

The LCO requires all four channels of the Overtemperature ΔT trip Function to be OPERABLE. Note that the Overtemperature ΔT Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this trip Function is not required to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Overpower ΔT

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding failure) under all possible overpower conditions. This trip Function also limits the required range of the Overtemperature ΔT trip Function and provides a backup to the Power Range Neutron Flux—High Setpoint trip. The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature—the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;
- rate of change of reactor coolant average temperature—including dynamic compensation for the delays between the core and the temperature measurement system; and
- axial power distribution f(ΔI) – the Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the design limit, as indicated by the difference between the upper and lower NIS power range detectors, the Trip Setpoint is reduced in accordance with Note 2 of Table 3.3.1-1.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Overpower ΔT (continued)

The Overpower ΔT trip Function is calculated in two channels for each loop as described in Note 2 of Table 3.3.1-1. A reactor trip occurs if the Overpower ΔT trip setpoint is reached in two-out-of-four channels. Since the temperature signals are used for other control functions, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation and a single failure in the remaining channels providing the protection function actuation. Section 7.2.5 of Reference 4 discusses control and protection system interactions for this function. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overpower ΔT condition and may prevent an unnecessary reactor trip.

The LCO requires four channels of the Overpower ΔT trip Function to be OPERABLE. Note that the Overpower ΔT trip Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overpower ΔT trip Function must be OPERABLE. These are the only MODES where enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel. In MODE 3, 4, 5, or 6, this trip Function is not required to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Pressurizer Pressure

The same sensors (PT-429, PT-430, and PT-431) provide input to the Pressurizer Pressure – High and – Low trips and the Overtemperature ΔT trip with the exception that the Pressurizer Pressure – Low and Overtemperature ΔT trips also receive input from PT-449. Since the Pressurizer Pressure channels are also used for other control functions, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Section 7.2.5 of Reference 4 discusses control and protection system interactions for this function.

a. Pressurizer Pressure – Low

The Pressurizer Pressure – Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure. The LCO requires four channels of the Pressurizer Pressure – Low trip Function to be OPERABLE. Included within the four channels are lead time and lead/lag constraints.

In MODE 1, when DNB is a major concern, the Pressurizer Pressure – Low trip function must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock (8.5% RTP). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, the Pressurizer Pressure – Low trip Function is not required to be OPERABLE because no conceivable power distributions can occur that would cause DNB concerns.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Pressurizer Pressure - High

The Pressurizer Pressure - High trip Function ensures that protection is provided against overpressurizing the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions. The LCO requires three channels of the Pressurizer Pressure - High trip Function to be OPERABLE.

In MODE 1 or 2, the Pressurizer Pressure - High trip Function must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the relief and safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure - High trip Function is not required to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate plant conditions and take corrective actions. Additionally, low temperature overpressure protection systems provide overpressure protection when in or below MODE 4.

8. Pressurizer Water Level - High

The Pressurizer Water Level - High trip Function provides a backup signal for the Pressurizer Pressure - High trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. This trip Function is not specifically modeled in the accident analysis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8. Pressurizer Water Level — High (continued)

The LCO requires three channels of the Pressurizer Water Level — High trip Function to be OPERABLE. The pressurizer level channels (LT-426, LT-427, and LT-428) are also used for other control functions. Section 7.2.5 of Reference 4 discusses control and protection system interactions for this function. The level channels do not actuate the safety valves, and the high pressure reactor trip is set below the safety valve setting. Therefore, with the slow rate of charging available, pressure overshoot due to level channel failure cannot cause the safety valve to lift before the reactor high pressure trip.

In MODE 1 or 2, when there is a potential for overfilling the pressurizer, the Pressurizer Water Level — High trip Function must be OPERABLE. In MODES 3, 4, 5, or 6, the Pressurizer Water Level — High trip Function is not required to be OPERABLE because transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate plant conditions and take corrective actions.

9. Reactor Coolant Flow - Low

The Reactor Coolant Flow — Low (Single Loop) and (Two Loops) trip Functions utilize three common flow transmitters per RCS loop to generate a reactor trip above 8.5% RTP (P-7 setpoint). Flow transmitters FT-411, FT-412, and FT-413 are used for RCS Loop A and FT-414, FT-415, and FT-416 are used for RCS Loop B.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Reactor Coolant Flow-Low (Single Loop)

The Reactor Coolant Flow-Low (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in the RCS loop, while avoiding reactor trips due to normal variations in loop flow. Above the P-8 setpoint, (50% RTP), a loss of flow in either RCS loop will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow-Low (Single Loop) trip Function channels per RCS loop to be OPERABLE in MODE 1 ≥ 50% RTP (above P-8 setpoint). Each loop is considered a separate Function for the purpose of this LCO.

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core. In MODE 1 below the P-8 setpoint the Reactor Coolant Flow-Low (Single Loop) trip Function is not required to be OPERABLE because a loss of flow in one loop has been evaluated and found to be acceptable (Ref. 6).

b. Reactor Coolant Flow-Low (Two Loops)

The Reactor Coolant Flow-Low (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in both RCS loops while avoiding reactor trips due to normal variations in loop flow.

The LCO requires three Reactor Coolant Flow-Low (Two Loops) trip Function channels per loop to be OPERABLE in MODE 1 above 8.5% RTP (P-7 setpoint) and before the Reactor Coolant Flow-Low (Single Loop) trip Function is OPERABLE (below the P-8 setpoint). Each loop is considered a separate Function for the purpose of this LCO.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Reactor Coolant Flow-Low (Two Loops) (continued)

Above the P-7 setpoint and below the P-8 setpoint, a loss of flow in both loops will initiate a reactor trip. Each loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

Below the P-7 setpoint, this trip Function is not required to be OPERABLE because all reactor trips on low flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on low flow in both RCS loops is automatically enabled. Above the P-8 setpoint, the Reactor Coolant Flow-Low (Two Loops) trip Function is not required to be OPERABLE because loss of flow in any one loop will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

10. RCP Breaker Position

Both RCP Breaker Position trip Functions (Single Loop and Two Loops) utilize a common auxiliary contact located on each RCP. These Functions anticipate the Reactor Coolant Flow-Low trips to avoid RCS heatup that would occur before the low flow trip actuates but are not specifically credited in the accident analysis.

a. Reactor Coolant Pump Breaker Position (Single Loop)

The RCP Breaker Position (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in one RCS loop. The position of each RCP breaker is monitored. If one RCP breaker is open above 50% RTP, a reactor trip is initiated. This trip Function will generate a reactor trip before the Reactor Coolant Flow-Low (Single Loop) Trip Setpoint is reached.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. RCP Breaker Position (Single Loop) (continued)

The LCO requires one RCP Breaker Position trip Function channel per RCP to be OPERABLE in MODE 1 ≥ 50% RTP (above the P-8 setpoint). Each RCP is considered a separate Function for the purpose of this LCO. One OPERABLE channel is sufficient for this trip Function because the RCS Flow-Low trip alone provides sufficient protection of plant SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of a pump.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-8 setpoint, when a loss of flow in any RCS loop could result in DNB conditions in the core, the RCP Breaker Position (Single Loop) trip Function must be OPERABLE. In MODE 1 below the P-8 setpoint, the RCP Breaker Position (Single Loop) trip Function is not required to be OPERABLE because a loss of flow in one loop has been evaluated and found to be acceptable (Ref. 6).

b. RCP Breaker Position (Two Loops)

The RCP Breaker Position (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in both RCS loops. The position of each RCP breaker is monitored. If both RCP breakers are open above 8.5% RTP (P-7 setpoint) and before the RCP Breaker Position (Single Loop) trip Function is OPERABLE (below the P-8 setpoint), a reactor trip is initiated. This trip Function will generate a reactor trip before the Reactor Coolant Flow-Low (Two Loops) Trip Setpoint is reached.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Reactor Coolant Pump Breaker Position (Two Loops) (continued)

The LCO requires one RCP Breaker Position trip Function channel per RCP to be OPERABLE in MODE 1 above the P-7 and below the P-8 setpoints. Each RCP is considered a separate Function for the purpose of this LCO. One OPERABLE channel is sufficient for this Function because the RCS Flow—Low trip alone provides sufficient protection of plant SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of an RCP.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the RCP Breaker Position (Two Loops) trip Function must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow (including RCP breaker position) are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in both RCS loops is automatically enabled. Above the P-8 setpoint, the RCP Breaker Position (Two Loops) trip Function is not required to be OPERABLE because a loss of flow in any one loop will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

11. Undervoltage - Bus 11A and 11B

The Undervoltage - Bus 11A and 11B reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in both RCS loops from a major network voltage disturbance. The voltage to each RCP is monitored. Above 8.5% RTP (the P-7 setpoint), an undervoltage condition detected on both Buses 11A and 11B will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow - Low (Two Loops) Trip Setpoint is reached. Time delays are incorporated into the Undervoltage Bus 11A and 11B channels to prevent reactor trips due to momentary electrical power transients.

The LCO requires two Undervoltage - Bus 11A and 11B trip Function channels per bus to be OPERABLE in MODE 1 above the P-7 setpoint. Each bus is considered a separate Function for the purpose of this LCO.

Below the P-7 setpoint, the Undervoltage - Bus 11A and 11B trip Function is not required to be OPERABLE because all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on Undervoltage - Bus 11A and 11B is automatically enabled.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

12. Underfrequency - Bus 11A and 11B

The Underfrequency - Bus 11A and 11B reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in both RCP loops from a major network frequency disturbance. An underfrequency condition will slow down the pumps, thereby reducing their coastdown time following a pump trip. The proper coastdown time is required so that reactor heat can be removed immediately after reactor trip. The frequency of each RCP bus is monitored. Above 8.5% RTP (the P-7 setpoint), a loss of frequency detected on both RCP buses will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow - Low (Two Loops) Trip Setpoint is reached. Time delays are incorporated into the Underfrequency RCPs channels to prevent reactor trips due to momentary electrical power transients.

The LCO requires two Underfrequency - Bus 11A and 11B channels per bus to be OPERABLE in Mode 1 above the P-7 setpoint. Each bus is considered a separate Function for the purpose of this LCO.

Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on Underfrequency - Bus 11A and 11B is automatically enabled.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

13. Steam Generator Water Level - Low Low

The Steam Generator (SG) Water Level - Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the Auxiliary Feedwater (AFW) System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low low level in any SG is indicative of a loss of heat sink for the reactor. Three level transmitters per SG (LT-461, LT-462, and LT-463 for SG A and, LT-471, LT-472, and LT-473 for SG B) provide input to the SG Level Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. This Function also performs the Engineered Safety Feature Actuation System (ESFAS) function of starting the AFW pumps on low low SG level. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor.

The LCO requires three trip Function channels of SG Water Level - Low Low per SG to be OPERABLE in MODES 1 and 2. Each SG is considered a separate Function for the purpose of this LCO.

In MODE 1 or 2, the SG Water Level - Low Low trip Function must be OPERABLE to ensure that a heat sink is available to the reactor. In MODE 3, 4, 5, or 6, the SG Water Level - Low Low trip Function is not required to be OPERABLE because the reactor is not operating. Decay heat removal is accomplished by the AFW System in MODE 3 and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

14. Turbine Trip

Credit for these trip Functions is not credited in the accident analysis.

a. Turbine Trip - Low Autostop Oil Pressure

The Turbine Trip - Low Autostop Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip from a power level above the P-9 setpoint. Below the P-9 setpoint this action will not actuate a reactor trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the stop valves close. Tripping the reactor in anticipation of loss of secondary heat removal acts to minimize the pressure and temperature transient on the reactor. Three pressure switches monitor the control oil pressure in the Autostop Oil System. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The plant is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure - High trip Function and RCS integrity is ensured by the pressurizer safety valves.

The LCO requires three trip Function channels of Turbine Trip - Low Autostop Oil Pressure to be OPERABLE in MODE 1 above P-9.

Below the P-9 setpoint, the Turbine Trip - Low Autostop Oil Pressure trip Function is not required to be OPERABLE because load rejection can be accommodated by the steam dump system. Therefore, a turbine trip does not actuate a reactor trip. In MODE 2, 3, 4, 5, or 6, the turbine is not operating, therefore, there is no potential for a turbine trip.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Turbine Trip – Turbine Stop Valve Closure

The Turbine Trip – Turbine Stop Valve Closure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip from a power level above the P-9 setpoint. Below the P-9 setpoint this action will not actuate a reactor trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the stop valves close. Tripping the reactor in anticipation of loss of secondary heat removal acts to minimize the pressure and temperature transient on the reactor. This trip Function will not and is not required to operate in the presence of a single channel failure. The plant is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure – High trip Function, and RCS integrity is ensured by the pressurizer safety valves. This trip Function is diverse to the Turbine Trip – Low Autostop Oil Pressure trip Function. Each turbine stop valve is equipped with one limit switch that inputs to the RTS. If both limit switches indicate that the stop valves are closed, a reactor trip is initiated.

This Function only measures the discrete position (open or closed) of the turbine stop valves. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

The LCO requires two Turbine Trip – Turbine Stop Valve Closure trip Function channels, one per valve, to be OPERABLE in MODE 1 above P-9. Both channels must trip to cause reactor trip.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Turbine Trip - Turbine Stop Valve Closure (continued)

Below the P-9 setpoint, the Turbine Trip - Turbine Stop Valve Closure trip Function is not required to be OPERABLE because a load rejection can be accommodated by the steam dump system. Therefore, a turbine trip does not actuate a reactor trip. In MODE 2, 3, 4, 5, or 6, the turbine is not operating, therefore there is no potential for a turbine trip.

15. Safety Injection Input from Engineered Safety Feature Actuation System

The Safety Injection (SI) Input from ESFAS ensures that if a reactor trip has not already been generated by the RTS, the ESFAS automatic actuation logic will initiate a reactor trip upon any signal that initiates SI. This trip is assumed in the safety analyses for the loss of coolant accident (LOCA). However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a reactor trip is initiated every time an SI signal is present.

Trip Setpoints are not applicable to this Function. The SI Input is provided by relays in the ESFAS. Therefore, there is no measurement signal with which to associate an LSSS.

The LCO requires two trip Function channels of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

16. Reactor Trip System Interlocks

Reactor protection interlocks (i.e., permissives) are provided to ensure reactor trips are in the correct configuration for the current plant status. They back up operator actions to ensure protection system Functions are not bypassed during plant conditions under which the safety analysis assumes the Functions are not bypassed. Therefore, the interlock Functions do not need to be OPERABLE when the associated reactor trip functions are outside the applicable MODES. These are:

a. Intermediate Range Neutron Flux, P-6 Permissive

The Intermediate Range Neutron Flux, P-6 permissive is actuated when any NIS intermediate range channel goes approximately one decade (1 E-10 amps) above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. The LCO requirement for the P-6 permissive ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux reactor trip by use of two defeat push buttons. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. When the source range trip is blocked, the high voltage to the detectors is also removed; and
- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the Source Range Neutron Flux reactor trip at 5E-11 amps.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Intermediate Range Neutron Flux, P-6 Permissive (continued)

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 permissive to be OPERABLE in MODE 2 when below the P-6 permissive setpoint.

Above the P-6 permissive setpoint, the Source Range Neutron Flux reactor trip will be blocked, and this Function is no longer required.

In MODE 3, 4, 5, or 6 the P-6 permissive does not have to be OPERABLE because the Source Range is providing the required core protection.

b. Low Power Reactor Trips Block, P-7 Permissive

The Low Power Reactor Trips Block, P-7 interlock is actuated by input from either the Power Range Neutron Flux, P-10, or from first stage turbine pressure. The LCO requirement for the P-7 permissive allows the bypass of the following Functions:

- Pressurizer Pressure - Low;
- Reactor Coolant Flow - Low (Two Loops);
- RCP Breaker Position (Two Loops);
- Undervoltage - Bus 11A and 11B; and
- Underfrequency - Bus 11A and 11B.

These reactor trip functions are not required below the P-7 setpoint since the RCS is capable of providing sufficient natural circulation without any RCP running.

The LCO requires four channels of Low Power Reactor Trips Block, P-7 permissive to be OPERABLE in MODE 1 $\geq$ 8.5% RTP.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Low Power Reactor Trips Block, P-7 Permissive (continued)

In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the permissive performs its Function when power level drops below 8.5% power, which is in MODE 1.

c. Power Range Neutron Flux, P-8 Permissive

The Power Range Neutron Flux, P-8, permissive is actuated at approximately 49% power as determined by two-out-of-four NIS power range detectors. The P-8 interlock allows the Reactor Coolant Flow - Low (Single Loop) and RCP Breaker Position (Single Loop) reactor trips on low flow in one or more RCS loops to be blocked so that a loss of a single loop will not cause a reactor trip. The LCO requirement for this trip Functions ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when ≥ 50% power.

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1 ≥ 50% RTP.

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 permissive must be OPERABLE. In MODE 1 < 50% RTP, this function is not required to be OPERABLE because a loss of flow in one loop will not result in DNB. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Power Range Neutron Flux, P-9 Permissive

The Power Range Neutron Flux, P-9 permissive is actuated at approximately 50% power as determined by two-out-of-four NIS power range detectors if the Steam Dump System is available and at 8% if the Steam Dump System is unavailable. The LCO requirement for this Function ensures that the Turbine Trip - Low Autostop Oil Pressure and Turbine Trip - Turbine Stop Valve Closure reactor trips are enabled above the P-9 setpoint. Above the P-9 setpoint, a turbine trip will cause a load rejection beyond the capacity of the Steam Dump System and RCS. A reactor trip is automatically initiated on a turbine trip when it is above the P-9 setpoint, to minimize the transient on the reactor.

The LCO require four channels of Power Range Neutron Flux, P-9 permissive to be OPERABLE in MODE 1 above the permissive setpoint.

In MODE 1 above the permissive setpoint, a turbine trip could cause a load rejection beyond the capacity of the Steam Dump System and RCS, so the Power Range Neutron Flux interlock must be OPERABLE. In MODE 1 below the permissive setpoint and MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at a power level sufficient to have a load rejection beyond the capacity of the Steam Dump System.

e. Power Range Neutron Flux, P-10 Permissive

The Power Range Neutron Flux, P-10 permissive is actuated at approximately 8% power, as determined by two-out-of-four NIS power range detectors. If power level falls below 8% RTP on 3 of 4 channels, the nuclear instrument trips will be automatically unblocked. The LCO requirement for the P-10 permissive ensures that the following Functions are performed:

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

e. <u>Power Range Neutron Flux, P-10 Permissive</u> (continued)

- on increasing power, the P-10 permissive allows the operator to manually block the Intermediate Range Neutron Flux and Power Range Neutron Flux - low reactor trips;
- on increasing power, the P-10 permissive automatically provides a backup signal to the P-6 permissive to block the Source Range Neutron Flux reactor trip, and also to de-energize the NIS source range detector;
- the P-10 interlock provides one of the two inputs to the P-7 interlock; and
- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux - Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 < 6% RTP and MODE 2.

OPERABILITY in MODE 1 < 6% RTP ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must also be OPERABLE in MODE 2 to ensure that core protection is providing during a startup or shutdown by the Power Range Neutron Flux - Low and Intermediate Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

17. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of individual trip mechanisms. The OPERABILITY requirement for the individual trip mechanisms is provided in Function 18 below. The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of all trip breakers associated with a single RTS logic train that are racked in, closed, and capable of supplying power to the CRD System. Thus, the train may consist of the main breaker, bypass breaker, or main breaker and bypass breaker, depending upon the system configuration. Two OPERABLE trains ensure no single failure can disable the RTS trip capability.

These trip Functions must be OPERABLE in MODE 1 or 2 because the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the CRD System is capable of rod withdrawal and all rods are not fully inserted.

18. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the CRD System, or declared inoperable under Function 17 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

These trip Functions must be OPERABLE in MODE 1 or 2 because the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the CRD System is capable of rod withdrawal and all rods are not fully inserted.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

19. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 17 and 18) and Automatic Trip Logic (Function 19) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. Each RTB is also equipped with a redundant bypass breaker to allow testing of the trip breaker while the plant is at power. The reactor trip signals generated by the RTS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RTS Automatic Trip Logic to be OPERABLE. Having two OPERABLE trains ensures that failure of a single logic train will not prevent reactor trip.

These trip Functions must be OPERABLE in MODE 1 or 2 because the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the CRD System is capable of rod withdrawal and all rods are not fully inserted.

The RTS instrumentation satisfies Criterion 3 of the NRC Policy Statement.

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.1-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to analytical values specified in plant procedures, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

(continued)

BASES

ACTIONS (continued)

As shown on Figure B 3.3.1-1, the RTS is comprised of multiple interconnected modules and components. For the purpose of this LCO, a channel is defined as including all related components from the field instrument to the Automatic Trip Logic (Function 19 in Table 3.3.1-1). Therefore, a channel may be inoperable due to the failure of a field instrument or a bistable failure which affects one or both RTS trains that is comprised of the RTBs and Automatic Trip Logic Function. The only exception to this are the Manual Reactor Trip and SI Input from ESFAS trip Functions which are defined strictly on a train basis (i.e., failure of these Functions may only affect one RTS train).

A.1

Condition A applies to all RTS protection functions. Condition A addresses the situation where one or more required channels for one or more Functions are inoperable or if both source range channels are inoperable. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

When the number of inoperable channels in a trip Function exceed those specified in all related Conditions associated with a trip Function, then the plant is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if the trip Function is applicable in the current MODE of operation. This essentially applies to the loss of more than one channel of any RTS Function except with respect to Conditions G and H.

B.1

Condition B applies to the Manual Reactor Trip Function in MODE 1 or 2 and in MODES 3, 4, and 5 with the CRD system capable of rod withdrawal or all rods not fully inserted. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. In this Condition, the remaining OPERABLE channel is adequate to perform the required safety function.

(continued)

BASES

ACTIONS

B.1 (continued)

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

C.1, C.2, and C.3

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 48 hour Completion Time of Condition B, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours, action must be initiated within 6 hours to ensure that all rods are fully inserted, and the Control Rod Drive System must be placed in a condition incapable of rod withdrawal within 7 hours. The Completion Times provide adequate time to exit the MODE of Applicability from full power operation in an orderly manner without challenging plant systems based on operating experience.

D.1

Condition D applies to the following reactor trip Functions:

- Power Range Neutron Flux — High;
- Power Range Neutron Flux — Low;
- Overtemperature ΔT;
- Overpower ΔT;
- Pressurizer Pressure — High;
- Pressurizer Water Level — High; and
- SG Water Level — Low Low.

(continued)

BASES

ACTIONS

D.1 (continued)

With one channel inoperable, the channel must be restored to OPERABLE status or placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition. For the Power Range Neutron Flux — High, Power Range Neutron Flux — Low, Overtemperature ΔT, and Overpower ΔT functions, this results in a one-out-of-three logic for actuation. For the Pressurizer Pressure — High and Pressurizer Water Level — High Functions, this results in a one-out-of two logic for actuation. For the SG Water Level — Low Low Function, this results in a one-out-of-two logic per each affected SG for actuation. The 6 hours allowed to place the inoperable channel in the tripped condition is consistent with Reference 9.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypass condition for up to 4 hours while performing surveillance testing of other channels. This includes placing the inoperable channel in the bypass condition to allow setpoint adjustments of other channels when required to reduce the setpoint in accordance with other Technical Specifications. This 4 hours is applied to each of the remaining OPERABLE channels. The 4 hour time limit is consistent with Reference 9.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

Condition E applies to the Intermediate Range Neutron Flux trip Function when THERMAL POWER is above the P-6 setpoint (5E-11 amp as derived from a bistable circuit of the intermediate range channels) and below the P-10 setpoint (6% RTP as derived from a bistable circuit of the Power Range channels) and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs a monitoring and protection function. With one NIS intermediate range channel inoperable, 2 hours is allowed to either reduce THERMAL POWER below the P-6 setpoint or increase THERMAL POWER above the P-10 setpoint. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel inoperability does not result in reactor trip.

Required Action E.2 is modified by a Note which states that the option to increase THERMAL POWER is not allowed if both intermediate range channels are inoperable or if THERMAL POWER is < 5E-11 amps. This prevents the plant from increasing THERMAL POWER when the trip capability of the Intermediate Range Neutron Flux trip Function is not available or if the plant has not yet entered this trip Function's MODE of Applicability.

(continued)

BASES

ACTIONS (continued)

F.1, F.2, and F.3

Condition F applies to the Source Range Neutron Flux trip Function when in MODE 2, below the P-6 setpoint. In this Condition, the NIS source range performs the monitoring and protection functions. With two channels inoperable, the RTBs and RTBBs must be opened immediately. With the RTBs and RTBBs opened, the core is in a more stable condition.

With one channel inoperable, operations involving positive reactivity additions shall be suspended immediately. This will preclude any power escalation since with only one source range channel OPERABLE, core protection is severely reduced. The inoperable channel must also be restored within 48 hours.

G.1

If the Required Actions of Condition D, E, or F cannot be met within the specified Completion Times, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in MODE 3 within the next 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

H.1, H.2, and H.3

Condition H applies to an inoperable source range channel in MODE 3, 4, or 5 with the CRD System capable of rod withdrawal or all rods not fully inserted. In this Condition, the NIS source range performs the monitoring and protection functions. With two channels inoperable, at least one channel must be restored to OPERABLE status within 1 hour. The Completion Time of 1 hour is reasonable considering the low probability of an event occurring during this interval.

(continued)

BASES

ACTIONS

H.1, H.2, and H.3 (continued)

With one of the source range channels inoperable, operations involving positive reactivity additions must be suspended immediately and 48 hours is allowed to restore it to OPERABLE status. The suspension of positive reactivity additions will preclude any power escalation.

I.1 and I.2

If the Source Range trip Function cannot be restored to OPERABLE status within the required Completion Time of Condition H, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, action must be immediately initiated to fully insert all rods. Additionally, the CRD System must be placed in a condition incapable of rod withdrawal within 1 hour. The Completion Time of 1 hour is sufficient to accomplish the Required Action, and takes into account the low probability of an event occurring during this interval.

J.1

Condition J applies when the required Source Range Neutron Flux channel is inoperable in MODE 3, 4, or 5 with the CRD System not capable of rod withdrawal and all rods are fully inserted. In this Condition, the NIS source range performs the monitoring function. With no source range channels OPERABLE, operations involving positive reactivity additions shall be suspended immediately. This will preclude any power escalation.

(continued)

BASES

ACTIONS

J.1 (continued)

Also, the SDM must be verified once within 12 hours and every 12 hours thereafter as per SR 3.1.1.1, SDM verification. With no source range channels OPERABLE, core protection is severely reduced. Verifying the SDM once per 12 hours allows sufficient time to perform the calculations and determine that the SDM requirements are met and to ensure that the core reactivity has not changed. Required Action J.1 precludes any positive reactivity additions; therefore, core reactivity should not be increasing, and a 12 hour Frequency is adequate. The Completion Time of once per 12 hours is based on operating experience in performing the Required Actions and the knowledge that plant conditions will change slowly.

K.1

Condition K applies to the following reactor trip Functions:

- Pressurizer Pressure — Low;
- Reactor Coolant Flow — Low (Two Loops);
- RCP Breaker Position (Two Loops);
- Undervoltage — Bus 11A and 11B; and
- Underfrequency — Bus 11A and 11B.

With one channel inoperable, the inoperable channel must be restored to OPERABLE status or placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a reactor trip. The 6 hours allowed to place the channel in the tripped condition is consistent with Reference 9 if the inoperable channel cannot be restored to OPERABLE status.

(continued)

BASES

ACTIONS

K.1 (continued)

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel(s), and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition K.

For the Reactor Coolant Flow - Low (Two Loops) Function, Condition K applies on a per loop basis. For the RCP Breaker Position (Two Loops) Function, Condition K applies on a per RCP basis. For Undervoltage - Bus 11A and 11B and underfrequency - Bus 11A and 11B, Condition K applies on a per bus basis. This allows one inoperable channel from each loop, RCP, or bus to be considered on a separate condition entry basis.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing surveillance testing of the other channels. The 4 hour time limit is consistent with Reference 9. The 4 hours is applied to each of the remaining OPERABLE channels.

L.1

If the Required Action and Completion Time of Condition K is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in MODE 1 < 8.5% RTP (P-7 setpoint) at which point the Function is no longer required. An alternative is not provided for increasing THERMAL POWER above the P-8 setpoint for the Reactor Coolant Flow - Low (Two Loops) and RCP Breaker Position (Two Loops) trip Functions since this places the plant in Condition M. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 1 < 8.5% RTP from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

M.1

Condition M applies to the Reactor Coolant Flow—Low (Single Loop) reactor trip Function. With one channel per loop inoperable, the inoperable channel must be restored to OPERABLE status or placed in the tripped condition within 6 hours. The 6 hours allowed to restore the channel to OPERABLE status or place in trip is consistent with Reference 9.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing surveillance testing of the other channels. The 4 hours is applied to each of the two OPERABLE channels. The 4 hour time limit is consistent with Reference 9.

N.1

Condition N applies to the RCP Breaker Position (Single Loop) trip Function. There is one breaker position device per RCP breaker. With one channel per RCP inoperable, the inoperable channel must be restored to OPERABLE status within 6 hours. The 6 hours allowed to restore the channel to OPERABLE status is consistent with Reference 9.

O.1

If the Required Action and associated Completion Time of Condition M or N is not met, the plant must be placed in a MODE where the Functions are not required to be OPERABLE. To achieve this status, THERMAL POWER must be reduced to < 50% RTP (P-8 setpoint) within the next 6 hours. The Completion Time of 6 hours is consistent with Reference 9.

(continued)

BASES

ACTIONS (continued)

P.1

Condition P applies to Turbine Trip on Low Autostop Oil Pressure or on Turbine Stop Valve Closure in MODE 1 above the P-9 setpoint. With one channel inoperable, the inoperable channel must be restored to OPERABLE status or placed in the tripped condition within 6 hours. If placed in the tripped Condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. The 6 hours allowed to place the inoperable channel in the tripped condition is consistent with Reference 9.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing surveillance testing of the other channels. The 4 hours is applied to each remaining OPERABLE channel. The 4 hour time limit is consistent with Reference 9.

Q.1, Q.2.1, and Q.2.2

If the Required Action and Associated Completion Time of Condition P are not met, the plant must be placed in a MODE where the Turbine Trip Functions are no longer required to be OPERABLE. To achieve this status, THERMAL POWER must be reduced to < 50% RTP (P-9 setpoint) within the next 6 hours. The Completion Time of 6 hours is consistent with Reference 9.

The Steam Dump system must also be verified OPERABLE within 7 hours or THERMAL POWER must be reduced to < 8% RTP. This ensures that either the secondary system or RCS is capable of handling the heat rejection following a reactor trip. The Completion Times are reasonable considering the need to perform the actions in an orderly manner and the low probability of an event occurring in this time.

(continued)

BASES

ACTIONS (continued)

R.1

Condition R applies to the SI Input from ESFAS reactor trip and the RTS Automatic Trip Logic in MODES 1 and 2. With one train inoperable, 6 hours is allowed to restore the train to OPERABLE status. The Completion Time of 6 hours to restore the train to OPERABLE status is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval.

The Required Action has been modified by a Note that allows bypassing one train up to 4 hours for surveillance testing, provided the other train is OPERABLE.

S.1 and S.2

Condition S applies to the P-6, P-7, P-8, P-9, and P-10 permissives. With one channel inoperable, the associated interlock must be verified to be in its required state for the existing plant condition within 1 hour or the associated RTS channel(s) must be declared inoperable. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions.

T.1

Condition T applies to the RTBs in MODES 1 and 2. With one train inoperable, 1 hour is allowed to restore the train to OPERABLE status. The 1 hour Completion Time is based on operating experience and the minimum amount of time allowed for manual operator actions.

The Required Action has been modified by two Notes. Note 1 allows one train to be bypassed for up to 2 hours for surveillance testing, provided the other train is OPERABLE. Note 2 allows one RTB to be bypassed for up to 6 hours for maintenance on undervoltage or shunt trip mechanisms if the other RTB train is OPERABLE.

(continued)

BASES

ACTIONS (continued)

U.1 and U.2

Condition U applies to the RTB Undervoltage and Shunt Trip Mechanisms (i.e., diverse trip features) in MODES 1 and 2. With two diverse trip features inoperable, at least one diverse trip feature must be restored to OPERABLE status within 1 hour. The Completion Time of 1 hour is reasonable considering the low probability of an event occurring during this time interval.

With one trip mechanism for one RTB inoperable, it must be restored to an OPERABLE status within 48 hours. The affected RTB shall not be bypassed while one of the diverse trip features is inoperable except for the time required to perform maintenance to one of the diverse trip features. The allowable time for performing maintenance of the diverse trip features is 6 hours for the reasons stated under Condition T. The Completion Time of 48 hours for Required Action U.2 is reasonable considering that in this Condition there is one remaining diverse trip feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

V.1

If the Required Action and Associated Completion Time of Condition R, S, T, or U is not met, the plant must be placed in a MODE where the Functions are no longer required to be OPERABLE. To achieve this status, the plant must be placed in MODE 3 within the next 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

W.1 and W.2

Condition W applies to the following reactor trip Functions in MODE 3, 4, or 5 with the CRD System capable of rod withdrawal or all rods not fully inserted:

- RTBs;
- RTB Undervoltage and Shunt Trip Mechanisms; and
- Automatic Trip Logic.

With two trip mechanisms inoperable, at least one trip mechanism must be restored to OPERABLE status within 1 hour. The Completion Time of 1 hour is reasonable considering the low probability of an event occurring during this time interval.

With one trip mechanism or train inoperable, the inoperable trip mechanism or train must be restored to OPERABLE status within 48 hours.

The Completion Time is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function, and given the low probability of an event occurring during this interval.

X.1 and X.2

If the Required Action and Associated Completion Time of Condition W is not met, the plant must be placed in a MODE where the Functions are no longer required. To achieve this status, action be must initiated immediately to fully insert all rods and the CRD System must be incapable of rod withdrawal within 1 hour. These Completion Times are reasonable, based on operating experience to exit the MODE of Applicability in an orderly manner.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

The SRs for each RTS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A Note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RTS Functions.

Note that each channel of process protection supplies both trains of the RTS. When testing Channel 1, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel 2, Channel 3, and Channel 4 (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies (Ref. 8).

SR 3.3.1.1

A CHANNEL CHECK is required for the following RTS trip functions:

- Power Range Neutron Flux—High;
- Power Range Neutron Flux—Low;
- Intermediate Range Neutron Flux;
- Source Range Neutron Flux;
- Overtemperature ΔT;
- Overpower ΔT;
- Pressurizer Pressure—Low;
- Pressurizer Pressure—High;
- Pressurizer Water Level—High;
- Reactor Coolant Flow—Low (Single Loop);
- Reactor Coolant Flow—Low (Two Loops); and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1 (continued)

- SG Water Level — Low Low

Performance of the CHANNEL CHECK once every 12 hours ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of more serious instrument conditions. A CHANNEL CHECK will detect gross channel failure; thus, it is a verification that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Channel check acceptance criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency of 12 hours is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.1.2

This SR compares the calorimetric heat balance calculation to the NIS Power Range Neutron Flux — High channel output every 24 hours. If the calorimetric exceeds the NIS channel output by > 2% RTP, the NIS is still OPERABLE but must be adjusted. If the NIS channel output cannot be properly adjusted, the channel is then declared inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

This SR is modified by a Note which states that this Surveillance is required only if reactor power is ≥ 50% RTP and that 12 hours is allowed for performing the first Surveillance after reaching 50% RTP. At lower power levels, calorimetric data are inaccurate.

The Frequency of every 24 hours is based on plant operating experience, considering instrument reliability and operating history data for instrument drift. Together these factors demonstrate the change in the absolute difference between NIS and heat balance calculated powers rarely exceeds 2% in any 24 hour period.

In addition, control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

This SR compares the incore system to the NIS channel output every 31 effective full power days (EFPD). If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted. If the NIS channel cannot be properly readjusted, the channel is then declared inoperable. This surveillance is performed to verify the f(ΔI) input to the Overtemperature ΔT Function.

This SR is modified by two Notes. Note 1 clarifies that the Surveillance is required to be performed within 7 days after THERMAL POWER is ≥ 50% RTP but prior to exceeding 90% RTP following each refueling and if it has not been performed within the last 31 EFPD. Note 2 states that performance of SR 3.3.1.6 satisfies this SR since it is a more comprehensive test.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3 (continued)

The Frequency of every 31 EFPD is based on plant operating experience, considering instrument reliability and operating history data for instrument drift. Also, the slow changes in neutron flux during the fuel cycle can be detected during this interval.

SR 3.3.1.4

This SR is the performance of a TADOT every 31 days on a STAGGERED TEST BASIS of the RTB, and the RTB Undervoltage and Shunt Trip Mechanisms. This test shall verify OPERABILITY by actuation of the end devices.

The test shall include separate verification of the undervoltage and shunt trip mechanisms except for the bypass breakers which do not require separate verification since no capability is provided for performing such a test at power. The independent test for bypass breakers is included in SR 3.3.1.11. However, the bypass breaker test shall include a local shunt trip. This test must be performed on the bypass breaker prior to placing it in service to take the place of a RTP.

The Frequency of every 31 days on a STAGGERED TEST BASIS is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.1.5

This SR is the performance of an ACTUATION LOGIC TEST on the RTS Automatic Trip Logic every 31 days on a STAGGERED TEST BASIS. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. All possible logic combinations, with and without applicable permissives, are tested for each protection function. The Frequency of every 31 days on a STAGGERED TEST BASIS is based on industry operating experience, considering instrument reliability and operating history data.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6

This SR is a calibration of the excore channels to the incore channels every 92 EFPD. If the measurements do not agree, the excore channels are still OPERABLE but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are then declared inoperable. This surveillance is performed to verify the f(ΔI) input to the Overtemperature ΔT Function.

This SR has been modified by a Note stating that this Surveillance is required to be performed within 7 days after THERMAL POWER is ≥ 50% RTP but prior to exceeding 90% RTP following each refueling and if it has not been performed within the last 92 EFPD.

The Frequency of 92 EFPD is adequate based on industry operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.7

This SR is the performance of a COT every 92 days for the following RTS functions:

- Power Range Neutron Flux—High;
- Source Range Neutron Flux (in MODE 3, 4, or 5 with CRD System capable of rod withdrawal or all rods not fully inserted);
- Overtemperature ΔT;
- Overpower ΔT;
- Pressurizer Pressure—Low;
- Pressurizer Pressurizer—High;
- Pressurizer Water Level—High;
- Reactor Coolant Flow—Low (Single Loop);

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

- Reactor Coolant Flow—Low (Two Loops); and
- SG Water Level—Low Low

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be within the Trip Setpoint of Table 3.3.1-1. The "as left" values must be consistent with the drift allowance used in the setpoint methodology (Ref. 8).

This SR is modified by a Note that provides a 4 hour delay in the requirement to perform this surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the plant is in MODE 3 with the RTBs closed for greater than 4 hours, this SR must be performed within 4 hours after entry into MODE 3.

The Frequency of 92 days is consistent with Reference 9.

SR 3.3.1.8

This SR is the performance of a COT as described in SR 3.3.1.7 for the Power Range Neutron Flux—Low, Intermediate Range Neutron Flux, and Source Range Neutron Flux (MODE 2), except that this test also includes verification that the P-6 and P-10 interlocks are in their required state for the existing plant condition. This SR is modified by two Notes that provide a 4 hour delay in the requirement to perform this surveillance. These Notes allow a normal shutdown to be completed and the plant removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance. The Frequency of every 92 days applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup and 4 hours after reducing power below P-10 or P-6.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the Source range channels. Once the plant is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the 4 hour limit. Four hours is a reasonable time to complete the required testing or place the plant in a MODE where this surveillance is no longer required. This test ensures that the NIS source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10 or < P-6) for periods > 4 hours.

SR 3.3.1.9

This SR is the performance of a TADOT for the Undervoltage—Bus 11A and 11B and Underfrequency—Bus 11A and 11B trip Functions. The Frequency of every 92 days is consistent with Reference 9.

This SR is modified by a Note that excludes verification of setpoints from the TADOT. Since this SR applies to Bus 11A and 11B undervoltage and underfrequency relays, setpoint verification requires elaborate bench calibration and is accomplished during the CHANNEL CALIBRATION required by SR 3.3.1.10.

SR 3.3.1.10

This SR is the performance of a CHANNEL CALIBRATION for the following RTS Functions:

- Power Range Neutron Flux—High;
- Power Range Neutron Flux—Low;
- Intermediate Range Neutron Flux;
- Source Range Neutron Flux;

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

- Overtemperature ΔT;
- Overpower ΔT;
- Pressurizer Pressure — Low;
- Pressurizer Pressure — High;
- Pressurizer Water Level — High;
- Reactor Coolant Flow — Low (Single Loop);
- Reactor Coolant Flow — Low (Two Loops);
- Undervoltage — Bus 11A and 11B;
- Underfrequency — Bus 11A and 11B;
- SG Water Level — Low Low;
- Turbine Trip — Low Autostop Oil Pressure; and
- Reactor Trip System Interlocks.

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the plant specific setpoint methodology (Ref. 8). The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

The Frequency of 24 months is based on the assumption of 24 month calibration intervals in the determination of the magnitude of equipment drift in the setpoint methodology.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the resistance temperature detectors (RTD) sensors shall include an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. This is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the power range neutron detectors consists of a normalization of the detectors based on a power calorimetric and flux map performed above 50% RTP. The CHANNEL CALIBRATION for the source range and intermediate range neutron detectors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. This Surveillance is not required for the NIS power range detectors for entry into MODE 2 or 1, and is not required for the NIS intermediate range detectors for entry into MODE 2, because the plant must be in at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed on the 24 month Frequency.

SR 3.3.1.11

This SR is the performance of a TADOT of the Manual Reactor Trip, RCP Breaker Position, and the SI Input from ESFAS trip Functions. This TADOT is performed every 24 months. This test independently verifies the OPERABILITY of the undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers and Reactor Trip Bypass Breakers.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.11 (continued)

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of setpoints from the TADOT because the Functions affected have no setpoints associated with them.

SR 3.3.1.12

This SR is the performance of a TADOT for Turbine Trip Functions which is performed prior to reactor startup if it has not been performed within the last 31 days. This test shall verify OPERABILITY by actuation of the end devices.

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

This SR is modified by a Note stating that verification of the Trip Setpoint does not have to be performed for this Surveillance. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to taking the reactor critical because this test cannot be performed with the reactor at power.

SR 3.3.1.13

This SR is the performance of a COT of the RTS interlocks every 24 months.

The Frequency is based on the known reliability of the interlocks and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

(continued)

BASES (continued)

REFERENCES

1. Atomic Industry Forum (AIF) GDC 14, Issued for comment July 10, 1967.
2. 10 CFR 100.
3. American National Standard, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," N18.2-1973.
4. UFSAR, Chapter 7.
5. UFSAR, Chapter 6.
6. UFSAR, Chapter 15.
7. IEEE-279-1971.
8. RG&E Engineering Work Request (EWR) 5126, "Guidelines for Instrument Loop Performance Evaluation and Setpoint Verification," August 1992.
9. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

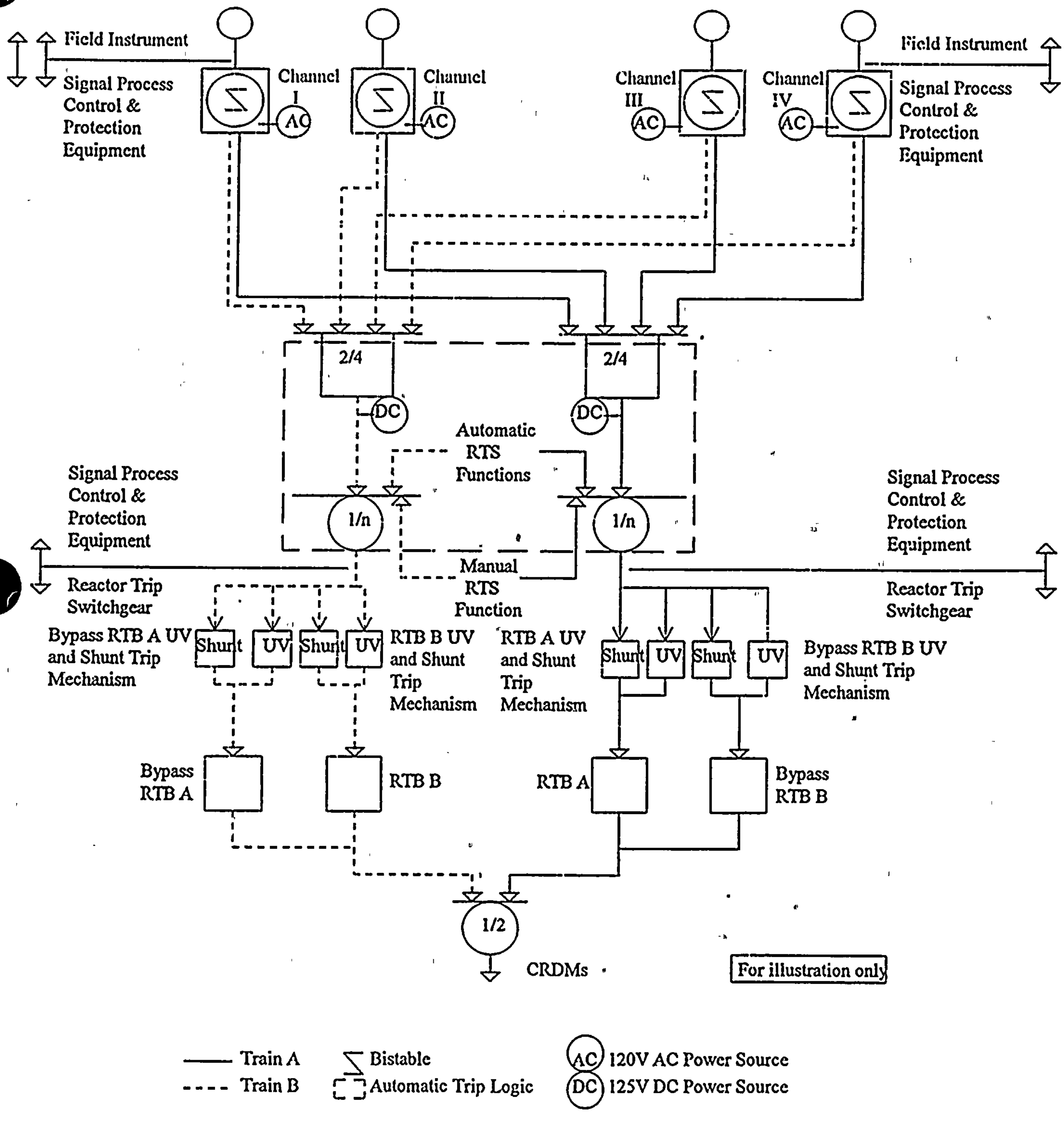


Figure B 3.3.1-1

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

Atomic Industrial Forum (AIF) GDC 15 (Ref. 1) requires that protection systems be provided for sensing accident situations and initiating the operation of necessary engineered safety features.

The ESFAS initiates necessary safety systems, based on the values of selected plant parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

The ESFAS instrumentation is segmented into two distinct but interconnected modules as described in UFSAR, Chapter 7 (Ref. 2):

- Field transmitters or process sensors; and
- Signal processing equipment.

These modules are discussed in more detail below.

<u>Field Transmitters and Process Sensors</u>

Field transmitters and process sensors provide a measurable electronic signal based on the physical characteristics of the parameter being measured. To meet the design demands for redundancy and reliability, two, three, and up to four field transmitters or sensors are used to measure required plant parameters. In many cases, field transmitters or sensors that input to the ESFAS are shared with the Reactor Trip System (RTS). To account for calibration tolerances and instrument drift, which is assumed to occur between calibrations, statistical allowances are provided. These statistical allowances provide the basis for determining acceptable "as left" and "as found" calibration values for each transmitter or sensor.

(continued)

BASES

BACKGROUND (continued)

Signal Processing Equipment

The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. These setpoints are defined in UFSAR, Chapter 6 (Ref. 3), Chapter 7 (Ref. 2), and Chapter 15 (Ref. 4). If the measured value of a plant parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the logic relays.

Generally, three or four channels of process control equipment are used for the signal processing of plant parameters measured by the field transmitters and sensors. If a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are typically sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function can still be accomplished with a two-out-of-two logic. If one channel fails in a direction that a partial Function trip occurs, a trip will not occur unless a second channel fails or trips in the remaining one-out-of-two logic.

If a parameter is used for input to the protection system and a control function, four channels with a two-out-of-four logic are typically sufficient to provide the required reliability and redundancy. This ensures that the circuit is able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Therefore, a single failure will neither cause nor prevent the protection function actuation. These requirements are described in IEEE-279-1971 (Ref. 5).

The actuation of ESF components is accomplished through master and slave relays. The protection system energizes the master relays appropriate for the condition of the plant. Each master relay then energizes one or more slave relays, which then cause actuation of the end devices.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, SI – Pressurizer Pressure – Low is a primary actuation signal for small break loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the plant. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as anticipatory actions to Functions that were credited in the accident analysis (Ref. 4).

This LCO requires all instrumentation performing an ESFAS Function to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of three or four channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three and the two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing an ESFAS initiation. Two logic or manual initiation channels are required to ensure no single failure disables the ESFAS.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO and Applicability of each ESFAS Function are provided in Table 3.3.2-1. Included on Table 3.3.2-1 are Allowable Values and Trip Setpoints for all applicable ESFAS Functions. Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the plant is operated within the LCOs, including any Required Actions that are in effect at the onset of the DBA and the equipment functions as designed.

The Trip Setpoints are the limiting values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the allowable tolerance band for CHANNEL CALIBRATION accuracy.

The Trip Setpoints used in the bistables are based on the analytical limits stated in References 2, 3, and 4. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays, calibration tolerances, instrumentation uncertainties, and instrument drift are taken into account. The Trip Setpoints specified in Table 3.3.2-1 are therefore conservatively adjusted with respect to the analytical limits (i.e., Allowable Values) used in the accident analysis. A detailed description of the methodology used to verify the adequacy of the existing Trip Setpoints, including their explicit uncertainties, is provided in Reference 6. If the measured setpoint exceeds the Trip Setpoint Value, the bistable is considered OPERABLE unless the Allowable Value as specified in plant procedures is exceeded. The Allowable Value specified in the plant procedures bounds that provided in Table 3.3.2-1 since the values in the table are typically those used in the accident analysis.

The Trip Setpoints and Allowable Values listed in Table 3.3.2-1 have been confirmed based on the methodology described in Reference 6, which incorporates all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The required channels of ESFAS instrumentation provide plant protection in the event of any of the analyzed accidents. ESFAS protection functions provided in Table 3.3.2-1 are as follows:

1. Safety Injection

Safety Injection (SI) provides two primary functions:

1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F); and

2. Boration to ensure recovery and maintenance of SDM (k_{eff} < 1.0).

These functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The SI signal is also used to initiate other Functions such as:

- Containment Isolation;
- Containment Ventilation Isolation;
- Reactor Trip;
- Feedwater Isolation; and
- Start of motor driven auxiliary feedwater (AFW) pumps.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

I. Safety Injection (continued)

These other functions ensure:

- Isolation of nonessential systems through containment penetrations;
- Trip of the reactor to limit power generation;
- Isolation of main feedwater (MFW) to limit secondary side mass losses; and
- Start of AFW to ensure secondary side cooling capability.

a. Safety Injection - Manual Initiation

This LCO requires one channel per train to be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. The operator can initiate SI at any time by using either of two pushbuttons on the main control board. This action will cause actuation of all components with the exception of Containment Isolation and Containment Ventilation Isolation.

The LCO for the Manual Initiation Function ensures the proper amount of redundancy is maintained in the manual ESFAS actuation circuitry to ensure the operator has manual ESFAS initiation capability.

Each channel consists of one pushbutton and the interconnecting wiring to the actuation logic cabinet. Each pushbutton actuates both trains. This configuration does not allow testing at power.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Safety Injection - Manual Initiation (continued)

This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is adequate time for the operator to evaluate plant conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Plant pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of plant systems. Also, this Function is not required in MODE 4 since it does not actuate Containment Isolation or Containment Ventilation Isolation.

b. Safety Injection - Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE in MODES 1, 2, 3, and 4. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

This Function is not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate plant conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Plant pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of plant systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Safety Injection - Containment Pressure - High

This signal provides protection against the following accidents:

- SLB inside containment;
- LOCA; and
- Feed line break inside containment.

Containment Pressure - High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic. The transmitters and electronics are located outside of containment with the sensing lines passing through containment penetrations to sense the containment atmosphere in three different locations.

Thus, the high pressure Function will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

Containment Pressure - High must be OPERABLE in MODES 1, 2, 3, and 4 because there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 5 and 6, Containment Pressure - High is not required to be OPERABLE because there is insufficient energy in the primary or secondary systems to pressurize the containment.

d. Safety Injection - Pressurizer Pressure - Low

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) atmospheric relief or safety valve;
- SLB;

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. <u>Safety Injection - Pressurizer Pressure - Low</u> (continued)

- Rod cluster control assembly ejection accidents (rod ejection);
- Inadvertent opening of a pressurizer relief or safety valve;
- LOCAs; and
- SG Tube Rupture.

Since there are dedicated protection and control channels, only three protection channels are necessary to satisfy the protective requirements.

The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment, rod ejection). Therefore, the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 (above the Pressurizer Pressure interlock) to mitigate the consequences of an HELB inside containment. This signal may be manually blocked by the operator below the interlock setpoint. Automatic SI actuation below this interlock setpoint is performed by the Containment Pressure - High signal.

This Function is not required to be OPERABLE in MODE 3 below the Pressurizer Pressure interlock setpoint. Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

e. Safety Injection - Steam Line Pressure - Low

Steam Line Pressure - Low provides protection against the following accidents:

- SLB;
- Feed line break; and
- Inadvertent opening of an SG atmospheric relief or an SG safety valve.

Steam line pressure transmitters provide control input, but the control function cannot initiate events that the Function acts to mitigate. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the protective requirements with a two-out-of-three logic on each steam line. Each steam line is considered a separate function for the purpose of this LCO.

With the transmitters located in the Intermediate Building, it is possible for them to experience adverse environmental conditions during a secondary side break. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

e. Safety Injection - Steam Line Pressure - Low (continued)

Steam Line Pressure - Low must be OPERABLE in MODES 1, 2, and 3 (above the Pressurizer Pressure interlock) when a secondary side break or stuck open SG atmospheric relief or safety valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the interlock setpoint. Below the interlock setpoint, a feed line break is not a concern. This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the plant to cause an accident.

2. Containment Spray (CS)

CS provides three primary functions:

1. Lowers containment pressure and temperature after an HELB in containment;
2. Reduces the amount of radioactive iodine in the containment atmosphere; and
3. Adjusts the pH of the water in containment sump B after a large break LOCA.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure;
- Limit the release of radioactive iodine to the environment in the event of a failure of the containment structure; and
- Minimize corrosion of the components and systems inside containment following a LOCA.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. CS (continued)

CS is actuated manually or by Containment Pressure - High High. The CS actuation signal starts the CS pumps and aligns the discharge of the pumps to the CS nozzle headers in the upper levels of containment. Water is initially drawn from the RWST by the CS pumps and mixed with a sodium hydroxide solution from the spray additive tank. During the recirculation phase of accident recovery, the spray pump suctions are manually shifted to containment sump B if continued CS is required.

a. CS - Manual Initiation

The operator can initiate CS at any time from the control room by simultaneously depressing two CS actuation pushbuttons. Because an inadvertent actuation of CS could have serious consequences, two pushbuttons must be simultaneously depressed to initiate both trains of CS. Therefore, the inoperability of either pushbutton fails both trains of manual initiation.

Manual initiation of CS must be OPERABLE in MODES 1, 2, 3, and 4 because a DBA could cause a release of radioactive material to containment and an increase in containment temperature and pressure requiring the operation of the CS System.

In MODES 5 and 6, this Function is not required to be OPERABLE because the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. In MODES 5 and 6, there is also adequate time for the operators to evaluate plant conditions and respond to mitigate the consequences of abnormal conditions by manually starting individual components.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. CS - Automatic Actuation Logic and Actuation Relays

Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

Automatic initiation of CS must be OPERABLE in MODES 1, 2, 3, and 4 because a DBA could cause a release of radioactive material to containment and an increase in containment temperature and pressure requiring the operation of the CS System.

In MODES 5 and 6, this Function is not required to be OPERABLE because the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. In MODES 5 and 6, there is also adequate time for the operators to evaluate plant conditions and respond to mitigate the consequences of abnormal conditions by manually starting individual components.

c. CS - Containment Pressure - High High

This signal provides protection against a LOCA or an SLB inside containment. The transmitters are located outside of containment with the sensing lines passing through containment penetrations to sense the containment atmosphere in three different locations. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

This is the only ESFAS Function that requires the bistable output to energize to perform its required action. It is not desirable to have a loss of power actuate CS, since the consequences of an inadvertent actuation of CS could be serious.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. <u>CS - Containment Pressure - High High</u> (continued)

The Containment Pressure - High High instrument function consists of two sets with three channels in each set. Each set is a two-out-of-three logic where the outputs are combined so that both sets tripped initiates CS. Each set is considered a separate function for the purposes of this LCO. Since containment pressure is not used for control, this arrangement exceeds the minimum redundancy requirements. Additional redundancy is warranted because this Function is energize to trip. Containment Pressure - High High must be OPERABLE in MODES 1, 2, 3 and 4 because a DBA could cause a release of radioactive material to containment and an increase in containment temperature and pressure requiring the operation of the CS System.

In MODES 5 and 6, this Function is not required to be OPERABLE because the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. In MODES 5 and 6, there is also adequate time for the operators to evaluate plant conditions and respond to mitigate the consequences of abnormal conditions by manually starting individual components.

3. <u>Containment Isolation</u>

Containment Isolation provides isolation of the containment atmosphere, and selected process systems that penetrate containment, from the environment. This Function is necessary to prevent or limit the release of radioactivity to the environment in the event of a LOCA.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Containment Isolation (continued)

Containment Isolation signals isolate all automatically isolatable process lines, except feedwater lines, main steam lines, and component cooling water (CCW). The main feedwater and steam lines are isolated by other functions since forced circulation cooling using the reactor coolant pumps (RCPs) and SGs is the preferred (but not required) method of decay heat removal. Since CCW is required to support RCP operation, not isolating CCW enhances plant safety by allowing operators to use forced RCS circulation to cool the plant. Isolating CCW may require the use of feed and bleed cooling, which could prove more difficult to control.

a. Containment Isolation - Manual Initiation

Manual Containment Isolation is actuated by either of two pushbuttons on the main control board. Either pushbutton actuates both trains. Manual initiation of Containment Isolation also actuates Containment Ventilation Isolation.

Manual initiation of Containment Isolation must be OPERABLE in MODES 1, 2, 3 and 4, because there is a potential for an accident to occur.

In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Containment Isolation. There also is adequate time for the operator to evaluate plant conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Containment Isolation - Automatic Actuation Logic and Actuation Relays

Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

Automatic initiation of Containment Isolation must be OPERABLE in MODES 1, 2, 3 and 4, because there is a potential for an accident to occur.

In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Containment Isolation. There also is adequate time for the operator to evaluate plant conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

c. Containment Isolation - Safety Injection

Containment Isolation is also initiated by all Functions that automatically initiate SI. The Containment Isolation requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all applicable initiating Functions and requirements.

4. Steam Line Isolation

Isolation of the main steam lines provides protection in the event of an SLB inside or outside containment. Closure of the main steam isolation valves (MSIVs) and their associated non-return check valves limits the accident to the blowdown from only the affected SG. For a SLB downstream of the MSIVs, closure of the MSIVs terminates the accident as soon as the steam lines depressurize. Steam Line Isolation also mitigates the effects of a feed line break and ensures a source of steam for the turbine driven AFW pump during a feed line break.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Steam Line Isolation - Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the control room. There are two actuation devices (one pushbutton and one switch) on the main control board for each MSIV. Each device can initiate action to immediately close its respective MSIV. The LCO requires one channel (device) per loop to be OPERABLE. Each loop is not considered a separate function since there is only one required per loop.

Manual initiation of steam line isolation must be OPERABLE in MODES 1, 2, and 3 because a secondary side break or stuck open valve could result in rapid depressurization of the steam lines. This could result in the release of significant quantities of energy and cause a cooldown of the primary system. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless both MSIVs are closed and de-activated. In MODES 4, 5, and 6, the steam line isolation function is not required to be OPERABLE because there is insufficient energy in the RCS and SGs to experience an SLB or other accident releasing significant quantities of energy.

b. Steam Line Isolation - Automatic Actuation Logic and Actuation Relays

Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. <u>Steam Line Isolation - Automatic Actuation Logic and Actuation Relays</u> (continued)

Automatic initiation of steam line isolation must be OPERABLE in MODES 1, 2, and 3 because a secondary side break or stuck open valve could result in rapid depressurization of the steam lines. This could result in the release of significant quantities of energy and cause a cooldown of the primary system. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless both MSIVs are closed and de-activated. In MODES 4, 5, and 6, the steam line isolation function is not required to be OPERABLE because there is insufficient energy in the RCS and SGs to experience an SLB or other accident releasing significant quantities of energy.

c. <u>Steam Line Isolation - Containment Pressure - High High</u>

This Function actuates closure of both MSIVs in the event of a LOCA or an SLB inside containment to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. The transmitters are located outside containment with the sensing lines passing through containment penetrations to sense the containment atmosphere in three different locations. Thus, they will not experience any adverse environmental conditions, and the Trip Setpoint reflects only steady state instrument uncertainties. Containment Pressure - High High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Steam Line Isolation - Containment Pressure - High High (continued)

Containment Pressure - High High must be OPERABLE in MODES 1, 2, and 3, because there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The steam line isolation Function must be OPERABLE in MODES 2 and 3 unless both MSIVs are closed and de-activated. In MODES 4, 5, and 6 the steam line isolation Function is not required to be OPERABLE because there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure - High High setpoint.

d. Steam Line Isolation - High Steam Flow Coincident With Safety Injection and Coincident With T_{avg} - Low

This Function provides closure of the MSIVs during an SLB or inadvertent opening of an SG atmospheric relief or safety valve to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment.

Two steam line flow channels per steam line are required to be OPERABLE for this Function. These are combined in a one-out-of-two logic to indicate high steam flow in one steam line. Each steam line is considered a separate function for the purpose of this LCO. The steam flow transmitters provide control inputs, but the control function cannot initiate events that the function acts to mitigate. Therefore, additional channels are not required to address control protection interaction issues. The one-out-of-two configuration allows online testing because trip of one high steam flow channel is not sufficient to cause initiation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Steam Line Isolation - High Steam Flow Coincident With Safety Injection and Coincident With T_{avg} - Low (continued)

With the transmitters (d/p cells) located inside containment, it is possible for them to experience adverse environmental conditions during an SLB event. Therefore, the Trip Setpoints reflect both steady state and adverse environmental instrument uncertainties.

The main steam line isolates only if the high steam flow signal occurs coincident with an SI and low RCS average temperature. The Main Steam Line Isolation Function requirements for the SI Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all applicable initiating functions and requirements.

Two channels of T_{avg} per loop are required to be OPERABLE for this Function. Each loop is considered a separate Function for the purpose of this LCO. The T_{avg} channels are combined in a logic such that any two of the four T_{avg} channels tripped in conjunction with SI and one of the two high steam line flow channels tripped causes isolation of the steam line associated with the tripped steam line flow channels. The accidents that this Function protects against cause reduction of T_{avg} in the entire primary system. Therefore, the provision of two OPERABLE channels per loop in a two-out-of-four configuration ensures no single failure disables the T_{avg} - Low Function. The T_{avg} channels provide control inputs, but the control function cannot initiate events that the Function acts to mitigate. Therefore, additional channels are not required to address control protection interaction issues.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Steam Line Isolation - High Steam Flow Coincident With Safety Injection and Coincident With T_{avg} - Low (continued)

This Function must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in rapid depressurization of the steam lines. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless both MSIVs are closed and de-activated. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the plant to have an accident.

e. Steam Line Isolation - High High Steam Flow Coincident With Safety Injection

This Function provides closure of the MSIVs during a steam line break (or inadvertent opening of an SG atmospheric relief or safety valve) to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment.

Two steam line flow channels per steam line are required to be OPERABLE for this Function. These are combined in a one-out-of-two logic to indicate high-high steam flow in one steam line. Each steam line is considered a separate function for the purpose of this LCO. The steam flow transmitters provide control inputs, but the control function cannot initiate events that the Function acts to mitigate. Therefore, additional channels are not required to address control protection interaction issues.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

e. Steam Line Isolation - High High Steam Flow Coincident With Safety Injection (continued)

The main steam lines isolate only if the high-high steam flow signal occurs coincident with an SI signal. Steamline isolation occurs only for the steam line associated with the tripped steam flow channels. The Main Steam Line Isolation Function requirements for the SI Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all applicable initiating functions and requirements.

This Function must be OPERABLE in MODES 1, 2, and 3 because a secondary side break or stuck open valve could result in rapid depressurization of the steam lines. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless both MSIV's are closed and de-activated. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the plant to have an accident.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. Feedwater Isolation

The primary function of the Feedwater Isolation signals is to prevent and mitigate the effects of high water level in the SGs which could cause carryover of water into the steam lines and result in excessive cooldown of the primary system. The SG high water level is due to excessive feedwater flows.

This Function is actuated by either a SG Water Level—High or an SI signal. The Function provides feedwater isolation by closing the Main Feedwater Regulating Valves (MFRVs) and the associated bypass valves. In addition, on an SI signal, the AFW System is automatically started, and the MFW pump breakers are opened which closes the MFW pump discharge valves. The SI signal was discussed previously.

a. Feedwater Isolation—Automatic Actuation Logic and Actuation Relays

Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

Automatic initiation must be OPERABLE in MODES 1, 2, and 3. The Feedwater Isolation Function is required to be OPERABLE in MODES 2 and 3 unless all MFRVs and associated bypass valves are closed and de-activated or isolated by a closed manual valve. In MODES 4, 5, and 6, the MFW System and the turbine generator are not in service and this Function is not required to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. <u>Feedwater Isolation - Steam Generator Water Level - High</u>

The Steam Generator Water Level - High Function must be OPERABLE in MODES 1, 2, and 3. The Feedwater Isolation Function is required to be OPERABLE in MODES 2 and 3 unless all MFRVs and associated bypass valves are closed and de-activated or isolated by a closed manual valve. In MODES 4, 5, and 6, the MFW System and the turbine generator are not in service and this Function is not required to be OPERABLE.

This signal provides protection against excessive feedwater flow. The ESFAS SG water level instruments have dedicated protection and control channels, only three protection channels are necessary to satisfy the protective requirements. Each SG is considered a separate Function for the purpose of this LCO. The Allowable Value for SG Water Level - High is a percent of narrow range instrument span. The Trip Setpoint is similarly calculated.

c. <u>Feedwater Isolation - Safety Injection</u>

The Safety Injection Function must be OPERABLE in MODES 1, 2, and 3. The Feedwater Isolation Function is required to be OPERABLE in MODES 2 and 3 unless all MFRVs and associated bypass valves are closed and de-activated or isolated by a closed manual valve. In MODES 4, 5, and 6, the MFW System and the turbine generator are not in service and this Function is not required to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Feedwater Isolation - Safety Injection (continued)

Feedwater Isolation is also initiated by all Functions that initiate SI. The Feedwater Isolation Function requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 1, SI, is referenced for all initiating functions and requirements.

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The preferred system has two motor driven pumps and a turbine driven pump, making it available during normal plant operation, during a loss of AC power, a loss of MFW, and during a Feedwater System pipe break (depending on break location). A Standby AFW (SAFW) is also available in the event the preferred system is unavailable. The normal source of water for the AFW System is the condensate storage tank (CST) which is not safety related. Upon a low level in the CST the operators can manually realign the pump suctions to the Service Water (SW) System which is the safety related water source. The SW System also is the safety related water source for the SAFW System. The AFW System is aligned so that upon a pump start, flow is initiated to the respective SGs immediately while the SAFW System is only manually initiated and aligned.

a. Auxiliary Feedwater - Manual Initiation

The operator can initiate AFW or SAFW at any time by using control switches on the Main Control board (one switch for each pump in each system). This action will cause actuation of their respective pump.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. <u>Auxiliary Feedwater - Manual Initiation</u> (continued)

The LCO for the Manual Initiation Function ensures the proper amount of redundancy is maintained to ensure the operator has manual AFW and SAFW initiation capability.

The LCO requires one channel per pump in each system to be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. In MODE 4, AFW actuation is not required to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation. This Function is not required to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink.

b. <u>Auxiliary Feedwater - Automatic Actuation Logic and Actuation Relays</u>

Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Auxiliary Feedwater - Automatic Actuation Logic and Actuation Relays (continued)

Automatic initiation of Auxiliary Feedwater must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. In MODE 4, AFW actuation is not required to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation. This Function is not required to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink.

c. Auxiliary Feedwater - Steam Generator Water Level - Low Low

SG Water Level - Low Low must be OPERABLE in MODES 1, 2, and 3 to provide protection against a loss of heat sink. A feed line break, inside or outside of containment, or a loss of MFW, would result in a loss of SG water level. SG Water Level - Low Low in either SG will cause both motor driven AFW pumps to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. SG Water Level - Low Low in both SGs will cause the turbine driven pump to start. In MODE 4, AFW actuation is not required to be OPERABLE because either AFW or RHR will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation. This Function is not required to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Auxiliary Feedwater - Steam Generator Water Level - Low Low (continued)

Each SG is considered a separate Function for the purpose of this LCO. The Allowable Value for SG Water Level - Low Low is a percent of narrow range instrument span. The Trip Setpoint is similarly calculated.

One train of SG Water Level - Low Low channels are powered from Instrument Bus D. Therefore, if Instrument Bus D is inoperable, one train of Automatic Actuation Logic and Relays should be declared inoperable.

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions (feed line break), the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

d. Auxiliary Feedwater - Safety Injection

The SI function must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. In MODE 4, AFW actuation is not required to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation. This Function is not required to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink.

An SI signal starts the motor driven and turbine driven AFW pumps. The AFW initiation functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all applicable initiating functions and requirements.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

e. <u>Auxiliary Feedwater - Undervoltage - Bus 11A and 11B</u>

The Undervoltage - Bus 11A and 11B Function must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. In MODE 4, AFW actuation is not required to be OPERABLE because either AFW or RHR will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation. This Function is not required to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink.

A loss of power to 4160 V Bus 11A and 11B will be accompanied by a loss of power to both MFW pumps and the subsequent need for some method of decay heat removal. The loss of offsite power is detected by a voltage drop on each bus. Loss of power to both buses will start the turbine driven AFW pump to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip. Each bus is considered a separate Function for the purpose of this LCO.

f. <u>Auxiliary Feedwater - Trip Of Both Main Feedwater Pumps</u>

A Trip of both MFW pumps is an indication of a loss of MFW and the subsequent need for some method of decay heat and sensible heat removal. The MFW pumps are equipped with a breaker position sensing device. An open supply breaker indicates that the pump is not running. Two OPERABLE channels per MFW pump satisfy redundancy requirements with two-out-of-two logic. Each MFW pump is considered a Separate Function for the purpose of this LCO. A trip of both MFW pumps starts both motor driven AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

f. Auxiliary Feedwater - Trip Of Both Main Feedwater Pumps (continued)

This Function must be OPERABLE in MODES 1 and 2. This ensures that at least one SG is provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of an accident. In MODES 3, 4, 5, and 6 the MFW pumps are not in operation, and thus pump trip is not indicative of a condition requiring automatic AFW initiation.

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.2-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. As shown on Figure B 3.3.2-1, the ESFAS is comprised of multiple interconnected modules and components. For the purpose of this LCO, a channel is defined as including all related components from the field instrument to the Automatic Actuation Logic. Therefore, a channel may be inoperable due to the failure of a field instrument, loss of 120 VAC instrument bus power or a bistable failure which affects one or both ESFAS trains. The only exception to this are the Manual ESFAS and Automatic Actuation Logic Functions which are defined strictly on a train basis. The Automatic Actuation Logic consists of all circuitry housed within the actuation subsystem, including the master relays, slave relays, and initiating relay contacts responsible for activating the ESF equipment.

(continued)

BASES

ACTIONS (continued)

A.1

Condition A applies to all ESFAS protection functions.

Condition A addresses the situation where one channel or train for one or more Functions are inoperable. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

When the number of inoperable channels in an ESFAS Function exceed those specified in all related Conditions associated with an ESFAS Function, then the plant is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if the ESFAS function is applicable in the current MODE of operation.

B.1

Condition B applies to the AFW - Trip of Both MFW Pumps ESFAS Function. If a channel is inoperable, 48 hours is allowed to return it to OPERABLE status. The specified Completion Time of 48 hours is reasonable considering the nature of this Function, the available redundancy, and the low probability of an event occurring during this interval.

C.1

If the Required Action and Completion Time of Condition B is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

D.1

Condition D applies to the following ESFAS Functions:

- Manual Initiation of SI;
- Manual Initiation of Steam Line Isolation;
- AFW — SG Water Level — Low Low; and
- AFW — Undervoltage — Bus 11A and 11B.

If a channel is inoperable, 48 hours is allowed to restore it to OPERABLE status. The specified Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE for each manual initiation, Function additional AFW actuation channels available besides the SG Water Level — Low Low and Undervoltage — Bus 11A and 11B AFW Initiation Functions, and the low probability of an event occurring during this interval.

E.1

Condition E applies to the automatic actuation logic and actuation relays for the following ESFAS Functions:

- Steam Line Isolation;
- Feedwater Isolation; and
- AFW.

Condition E addresses the train orientation of the protection system and the master and slave relays. If one train is inoperable, a Completion Time of 6 hours is allowed to restore the train to OPERABLE status. This Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this time interval. The Completion Time of 6 hours is consistent with Reference 7.

(continued)

BASES

ACTIONS (continued)

F.1

Condition F applies to the following Functions:

- Steam Line Isolation - Containment Pressure - High High;
- Steam Line Isolation - High Steam Flow Coincident With Safety Injection and Coincident With T_{avg} - Low;
- Steam Line Isolation - High - High Steam Flow Coincident With Safety Injection; and
- Feedwater Isolation - SG Water Level - High.

Condition F applies to Functions that typically operate on two-out-of-three logic. Therefore, failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements.

If one channel is inoperable, a Completion Time of 6 hours is allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Placing the channel in the tripped condition conservatively compensates for the inoperability, restores capability to accommodate a single failure, and allows operation to continue.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 4 hours for surveillance testing of other channels. This 4 hours applies to each of the remaining OPERABLE channels.

The Completion Time of 6 hours allowed to restore the channel to OPERABLE status or to place the inoperable channel in the tripped condition, and the 4 hours allowed for testing, are justified in Reference 7.

(continued)

BASES

ACTIONS (continued)

G.1

If the Required Actions and Completion Times of Conditions D, E, or F are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1

Condition H applies to the following ESFAS functions:

- Manual Initiation of CS; and
- Manual Initiation of Containment Isolation.

If a channel is inoperable, 48 hours is allowed to restore it to OPERABLE status. The specified Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE for each Function (except for CS) and the low probability of an event occurring during this interval.

I.1

Condition I applies to the automatic actuation logic and actuation relays for the following Functions:

- SI;
- CS; and
- Containment Isolation.

(continued)

BASES

ACTIONS

I.1 (continued)

Condition I addresses the train orientation of the protection system and the master and slave relays. If one train is inoperable, a Completion Time of 6 hours is allowed to restore the train to OPERABLE status. This Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. The Completion Time of 6 hours is consistent with Reference 7.

J.1

Condition J applies to the following Functions:

- SI – Containment Pressure – High; and
- CS – Containment Pressure – High High.

Condition J applies to Functions that operate on a two-out-of-three logic (for CS – Containment Pressure – High High there are two sets of this logic). Therefore, failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements.

If one channel is inoperable, a Completion Time of 6 hours is allowed to restore the channel to OPERABLE status or place it in the tripped condition. Placing the channel in the tripped condition conservatively compensates for the inoperability, restores capability to accommodate a single failure, and allows operation to continue.

The Required Action is modified by a Note that allows the inoperable channel to be bypassed for up to 4 hours for surveillance testing of other channels. The 4 hours applies to each of the remaining OPERABLE channels.

The Completion Time of 6 hours to restore the inoperable channel or place it in trip, and the 4 hours allowed for surveillance testing is justified in Reference 7.

(continued)

BASES

ACTIONS (continued)

K.1

If the Required Actions and Completion Times of Conditions H, I, or J are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

L.1

Condition L applies to the following Functions:

- SI – Pressurizer Pressure – Low; and
- SI – Steam Line Pressure – Low.

Condition L applies to Functions that operate on a two-out-of-three logic. Therefore, failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the FUnction in a one-out-of-two configuration that satisfies redundancy requirements.

If one channel is inoperable, a Completion Time of 6 hours is allowed to restore the channel to OPERABLE status or place it in the tripped condition. Placing the channel in the tripped condition conservatively compensates for the inoperability, restores capability to accommodate a single failure, and allows operation to continue.

The Required Action is modified by a Note that allows the inoperable channel to be bypassed for up to 4 hours for surveillance testing of other channels. The 4 hours applies to each of the remaining OPERABLE channels.

The Completion Time of 6 hours to restore the inoperable channel or place it in trip, and the 4 hours allowed for surveillance testing is justified in Reference 7.

(continued)

BASES

ACTIONS (continued)

M.1

If the Required Actions and Completion Times of Condition L are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and pressurizer pressure reduced to < 2000 psig within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

N.1

Condition N applies if a AFW Manual Initiation channel is inoperable. If a manual initiation switch is inoperable, the associated AFW or SAFW pump must be declared inoperable and the applicable Conditions of LCO 3.7.5, "Auxiliary Feedwater (AFW) System" must be entered immediately. Each AFW manual initiation switch controls one AFW or SAFW pump. Declaring the associated pump inoperable ensures that appropriate action is taken in LCO 3.7.5 based on the number and type of pumps involved.

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the SRs column of Table 3.3.2-1. Each channel of process protection supplies both trains of the ESFAS. When testing Channel 1, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel 2, Channel 3, and Channel 4 (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

Note 1 has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1

This SR is the performance of a CHANNEL CHECK for the following ESFAS Functions:

- SI – Containment Pressure – High;
- SI – Pressurizer Pressure – Low;
- SI – Steam Line Pressure – Low;
- CS – Containment Pressure – High High;
- Steam Line Isolation – Containment Pressure – High High;
- Steam Line Isolation – High Steam Flow Coincident with SI and T_{avg} – Low;
- Steam Line Isolation – High – High Steam Flow Coincident with SI;
- Feedwater Isolation – SG Water Level – High; and
- AFW – SG Water Level – Low Low.

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of more serious instrument conditions. A CHANNEL CHECK will detect gross channel failure; thus, it is a verification the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1 (continued)

CHANNEL CHECK acceptance criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency of 12 hours is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.2.2

This SR is the performance of a COT every 92 days for the following ESFAS functions:

- SI – Containment Pressure – High;
- SI – Pressurizer Pressure – Low;
- SI – Steam Line Pressure – Low;
- CS – Containment Pressure – High High;
- Steam Line Isolation – Containment Pressure – High High;
- Steam Line Isolation – High Steam Flow Coincident with SI and T_{avg} – Low;
- Steam Line Isolation – High – High Steam Flow Coincident with SI;
- Feedwater Isolation – SG Water Level – High; and
- AFW – SG Water Level – Low Low.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.2 (continued)

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found to be within the Allowable Values specified in Table 3.3.2-1 and established plant procedures. The "as left" values must be consistent with the drift allowance used in the setpoint methodology.

The Frequency of 92 days is consistent with in Reference 7. The Frequency is adequate based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.3

This SR is the performance of a TADOT every 92 days. This test is a check of the AFW — Undervoltage — Bus 11A and 11B Function.

The test includes trip devices that provide actuation signals directly to the protection system. The SR is modified by a Note that excludes verification of setpoints for relays. Relay setpoints require elaborate bench calibration and are verified during CHANNEL CALIBRATION. The Frequency of 92 days is adequate based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.4

This SR is the performance of a TADOT every 24 months. This test is a check of the SI, CS, Containment Isolation, Steam Line Isolation, and AFW Manual Initiations, and the AFW — Trip of Both MFW Pumps Functions. Each Function is tested up to, and including, the master transfer relay coils. The Frequency of 24 months is based on industry operating experience and is consistent with the typical refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Manual Initiations, and AFW — Trip of Both MFW Pumps Functions have no associated setpoints.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.5

This SR is the performance of a CHANNEL CALIBRATION every 24 months of the following ESFAS Functions:

- SI – Containment Pressure – High;
- SI – Pressurizer Pressure – Low;
- SI – Steam Line Pressure – Low;
- CS – Containment Pressure – High High;
- Steam Line Isolation – Containment Pressure – High High;
- Steam Line Isolation – High Steam Flow Coincident with SI and T_{avg} – Low;
- Steam Line Isolation – High – High Steam Flow Coincident with SI;
- Feedwater Isolation – SG Water Level – High;
- AFW – SG Water Level – Low Low; and
- AFW – Undervoltage – Bus 11A and 11B.

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the plant specific setpoint methodology. The "as left" values must be consistent with the drift allowance used in the setpoint methodology.

The Frequency of 24 months is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.6

This SR ensures the SI - Pressurizer Pressure - Low and SI - Steam Line Pressure - Low Functions are not bypassed when pressurizer pressure > 2000 psig while in MODES 1, 2, and 3. Periodic testing of the pressurizer pressure channels is required to verify the setpoint to be less than or equal to the limit.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology (Ref. 6). The setpoint shall be left set consistent with the assumptions of the current plant specific setpoint methodology.

If the pressurizer pressure interlock setpoint is nonconservative, then the Pressurizer Pressure - Low and Steam Line Pressure - Low Functions are considered inoperable. Alternatively, the pressurizer pressure interlock can be placed in the conservative condition (nonbypassed). If placed in the nonbypassed condition, the SR is met and the Pressurizer Pressure - Low and Steam Line Pressure - Low Functions would not be considered inoperable.

SR 3.3.2.7

This SR is the performance of an ACTUATION LOGIC TEST on all ESFAS Automatic Actuation Logic and Actuation Relays Functions every 24 months. This test includes the application of various simulated or actual input combinations in conjunction with each possible interlock state and verification of the required logic output. Relay and contact operation is verified by a continuance check or actuation of the end device.

The Frequency of 24 months is based on operating experience and the need to perform this testing during a plant shutdown to prevent a reactor trip from occurring.

(continued)

BASES (continued)

REFERENCES

1. Atomic Industrial Forum (AIF) GDC 15, Issued for Comment July 10, 1967.
2. UFSAR, Chapter 7.
3. UFSAR, Chapter 6.
4. UFSAR, Chapter 15.
5. IEEE-279-1971.
6. EWR-5126, "Guidelines For Instrument Loop Performance Evaluation and Setpoint Verification," August 1992.
7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

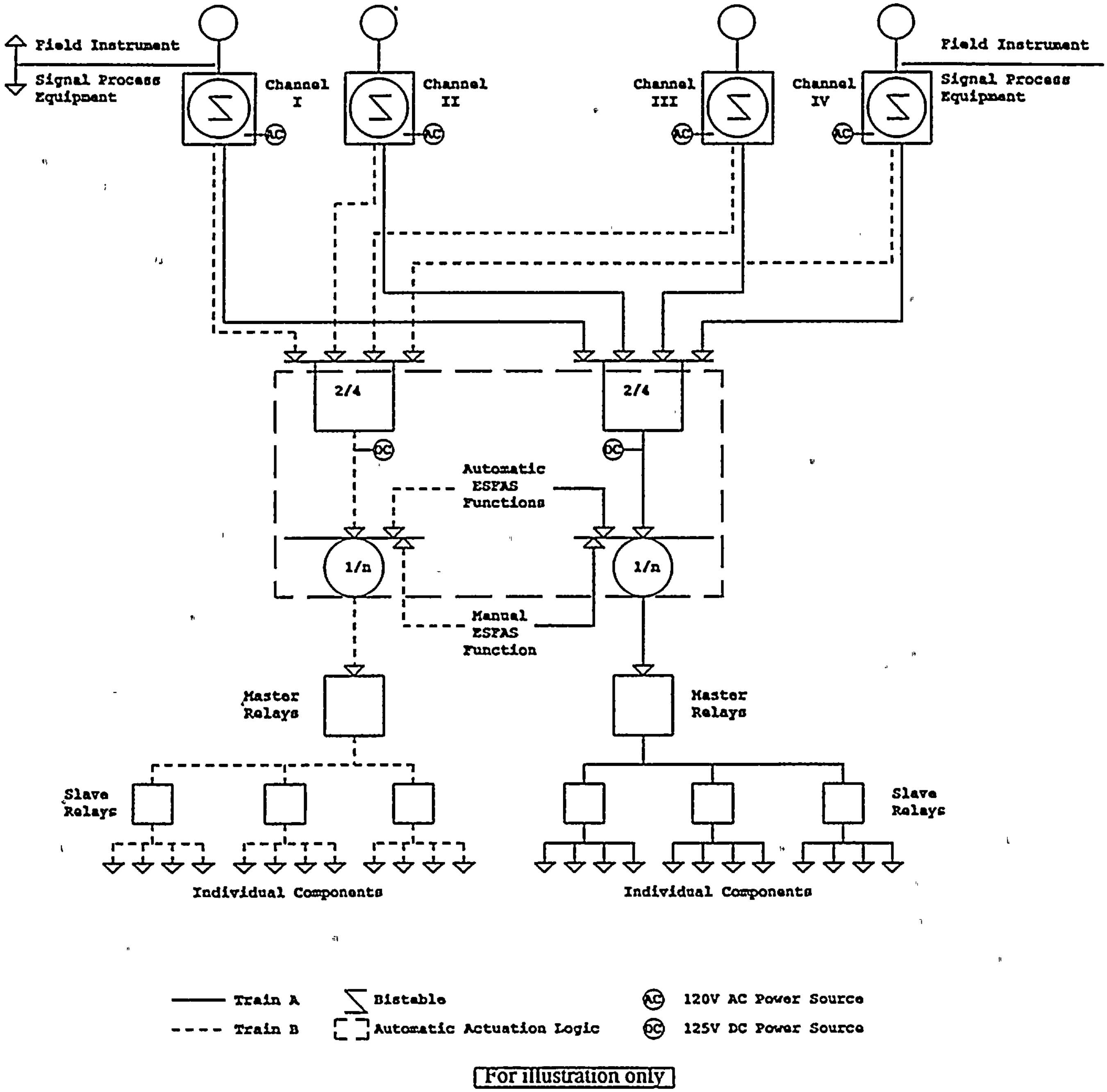


Figure B 3.3.2-1

B 3.3 INSTRUMENTATION

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display plant variables that provide information required by the control room operators during accident conditions. This instrumentation provides the necessary support for the operator to take required manual actions, verify that automatic and required manual safety functions have been completed, and to determine if fission product barriers have been breached following a Design Basis Accident (DBA).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected plant parameters to monitor and assess plant status and behavior during an accident.

The availability of accident monitoring instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. These essential instruments are identified in Reference 1 addressing the recommendations of Regulatory Guide 1.97 (Ref. 2) as required by Supplement 1 to NUREG-0737 (Ref. 3).

The instrument channels required to be OPERABLE by this LCO provide information for key parameters identified during implementation of Regulatory Guide 1.97 as Category I variables. Category I variables are organized into four types and are the key variables deemed risk significant because they are needed to:

a. Provide the primary information required for the control room operator to take specific manually controlled actions for which no automatic control is provided, and that are required for safety systems to accomplish their safety functions for DBAs (Type A).

b. Provide the primary information required for the control room operator to verify that required automatic and manually controlled functions have been accomplished (Type B);

(continued)

BASES

BACKGROUND (continued)

c. Provide information to the control room operators that will enable them to determine the likelihood of a gross breach of the barriers to radioactivity release (Type C); and

d. Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat (Type E).

All Type A and key Type B, C, and E parameters have been identified as Category I variables in Reference 1 which also provides justification for deviating from the NRC proposed list of Category I variables.

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the availability of Regulatory Guide 1.97 Category I variables so that the control room operating staff can:

- Perform the diagnosis specified in the emergency operating procedures for the primary success path of DBAs (e.g., loss of coolant accident (LOCA));
- Take the specified, pre-planned, manually controlled actions, for which no automatic control is provided, and that are required for safety systems to accomplish their safety function;
- Determine whether required automatic and manual safety functions have been accomplished;
- Determine the likelihood of a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of the NRC Policy Statement. Category I, non-Type A, instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, Category I, non-Type A, variables are important for reducing public risk and satisfy Criterion 4.

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, which provide information required by the control room operators to perform certain manual actions specified in the plant Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses Regulatory Guide 1.97 instruments that have been designated Category I, non-Type A.

The OPERABILITY of the PAM instrumentation ensures there is sufficient information available on selected plant parameters to monitor and assess plant status following an accident.

This LCO requires two OPERABLE channels for most Functions. Two OPERABLE channels ensure no single failure prevents operators from obtaining the information necessary to determine the safety status of the plant, and to bring the plant to and maintain it in a safe condition following an accident.

Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information. More than two channels may be required if failure of one accident monitoring channel results in information ambiguity (that is, the redundant displays disagree) that could lead operators to defeat or fail to accomplish a required safety function.

Table 3.3.3-1 lists all Category I variables identified by Reference 1.

(continued)

BASES

LCO (continued)

Category I variables are considered OPERABLE when they are capable of providing immediately accessible display and continuous readout in the control room. The Hydrogen Monitors are considered OPERABLE when continuous readout is available in the Control Room or in the relay room. Each channel must also be supplied by separate electrical trains except as noted below. In addition, in accordance with LCO 3.0.6, it is not required to declare a supported system inoperable due to the inoperability of the support system (e.g., electric power). Since the inoperability of Instrument Bus D does not have any associated Required Actions, the loss of this power source may affect the OPERABILITY of the Pressurizer Pressure and SG Water Level (Narrow Range) Functions.

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1.

1. Pressurizer Pressure

Pressurizer Pressure is a Type A variable used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Pressurizer pressure is also used to verify the plant conditions necessary to establish natural circulation in the RCS and to verify that the plant is maintained in a safe shutdown condition. Any of the following combinations of pressure transmitters comprise the two channels required for this function:

- PT-429 and PT-431;
- PT-430 and PT-431;
- PT-429 and PT-449;
- PT-430 and PT-449; or
- PT-431 and PT-449

The loss of Instrument Bus D requires declaring PT-449 inoperable.

(continued)

BASES

LCO (continued)

2. Pressurizer Level

Pressurizer Level is a Type A variable used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Pressurizer water level is also used to verify that the plant is maintained in a safe shutdown condition. Any of the following combinations of level transmitters comprise the two channels required for this function:

- LT-426 and LT-428; or
- LT-427 and LT-428.

3, 4. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures

RCS Hot and Cold Leg Temperatures are Category I variables (RCS Cold Leg Temperature is also a Type A variable) provided for verification of core cooling and long term surveillance of RCS integrity.

RCS hot and cold leg temperatures are used to determine RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. RCS subcooling margin is also used for plant stabilization and cooldown control.

In addition, RCS cold leg temperature is used in conjunction with RCS hot leg temperature to verify natural circulation in the RCS.

Temperature inputs are provided by two independent temperature sensor resistance elements and associated transmitters in each loop. Temperature elements TE-409B-1 and TE-410B-1 provide the required RCS cold leg temperature input for RCS Loops A and B, respectively. Temperature elements TE-409A-1 and TE-410A-1 provide the required RCS hot leg temperature input for RCS Loops A and B, respectively.

(continued)

BASES

LCO (continued)

5. RCS Pressure (Wide Range)

RCS wide range pressure is a Type A variable provided for verification of core cooling and the long term surveillance of RCS integrity.

RCS pressure is used to verify delivery of SI flow to the RCS from at least one train when the RCS pressure is below the SI pump shutoff head. RCS pressure is also used to verify closure of manually closed pressurizer spray line valves and pressurizer power operated relief valves (PORVs) and for determining RCS subcooling margin.

RCS pressure can also be used:

- to determine whether to terminate actuated SI or to reinitiate stopped SI;
- to determine when to reset SI and stop the residual heat removal pumps (RHR);
- to manually restart the RHR pumps;
- as reactor coolant pump (RCP) trip criteria;
- to make a determination on the nature of the accident in progress and where to go next in the emergency operating procedure; and
- to determine whether to operate the pressurizer heaters.

RCS pressure is also related to three decisions about depressurization. They are:

- to determine whether to proceed with primary system depressurization;
- to verify termination of depressurization; and
- to determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

(continued)

BASES

LCO

5. RCS Pressure (Wide Range) (continued)

RCS pressure is a Type A variable because the operator uses this indication to monitor the cooldown of the RCS following a steam generator tube rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting steam generator (SG) pressure or level, would use this indication.

RCS pressure transmitters PT-420 and PT-420A provide the two required channels for this function.

6. RCS Subcooling Monitor

RCS Subcooling Monitor is a Type A variable provided for verification of core cooling and long term surveillance of RCS integrity. The RCS Subcooling Monitor is used to provide information to the operator, derived from RCS hot leg temperature and RCS pressure, on subcooling. RCS subcooling margin is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. RCS subcooling margin is also used for plant stabilization and cooldown control.

The emergency operating procedures determine RCS subcooling margin based on the core exit thermocouples (CETs) and RCS pressure. Therefore, any of the following combination of parameters comprise the two required channels for this function:

- TI-409A and TI-410A; or
- One pressurizer pressure transmitter and two CETs in each of the four quadrants supplied by electrical train A and train B (i.e., total of two pressurizer pressure transmitters and 16 CETs).

(continued)

BASES

LCO (continued)

7. Reactor Vessel Water Level

Reactor Vessel Water Level is a Type A variable provided for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy.

When both RCPs are stopped, the Reactor Vessel Water Level Indication System (RVLIS) provides a direct measurement of the collapsed liquid level above the fuel alignment plate. The collapsed level represents the amount of liquid mass that is in the reactor vessel above the core. When the RCPs are operating, RVLIS indicates the fluid fraction of the RCS. Measurement of the collapsed water level or fluid fraction is selected because it is a direct indication of the water inventory.

Level transmitters LT-490A and LT-490B provide the two required channels for this function.

8. Containment Sump B Water Level

Containment Sump B Water Level is a Type A variable provided for verification and long term surveillance of RCS integrity.

Containment Sump B Water Level is used to determine:

- containment sump level for accident diagnosis;
- when to begin the recirculation procedure; and
- whether to terminate SI, if still in progress.

Level transmitters LT-942 and LT-943, each with five discrete level switches, provide the two required channels for this function.

(continued)

BASES

LCO (continued)

9. Containment Pressure (Wide Range)

Containment Pressure (Wide Range) is a Type A variable provided for verification of RCS and containment OPERABILITY.

Containment Pressure (Wide Range) is used to determine the type of accident in progress and when, and if, to use emergency operating procedure containment adverse values.

Any of the following combinations of pressure transmitters comprise the two required channels for this function:

- PT-946 and PT-948; or
- PT-950 and PT-948.

10. Containment Area Radiation (High Range)

Containment Area Radiation (High Range) is a Type E Category I variable provided to monitor for the potential of significant radiation releases into containment and to provide release assessment for use by operators in determining the need to invoke site emergency plans.

Containment radiation level is used to determine the type of accident in progress (e.g., LOCA), and when, or if, to use emergency operating procedure containment adverse values.

Radiation monitors R-29 and R-30 are used to provide the two required channels for this function.

11. Hydrogen Monitors

Hydrogen Concentration is a Type C Category I variable provided to detect high hydrogen concentration conditions that represent a potential for containment breach from a hydrogen explosion. This variable is also important in verifying the adequacy of mitigating actions.

(continued)

BASES

LCO

11. Hydrogen Monitors (continued)

Hydrogen monitors HMSLCPA and HMSLCPB provide the two required channels for this function. In addition, the Post Accident Sampling System may take the place of one of these monitors. The PASS system Hydrogen Function is not required to provide continuous readout in the control room or relay room for OPERABILITY.

12. Condensate Storage Tank (CST) Level

CST Level is a Type A variable provided to ensure a water supply is available for the preferred Auxiliary Feedwater (AFW) System. The CST consists of two identical tanks connected by a common outlet header.

CST level is used to determine:

- if sufficient CST inventory is available immediately following a loss of normal feedwater or small break LOCA; and
- when to manually replenish the CST or align the safety related source of water (service water) to the preferred AFW system.

Level transmitters LT-2022A and LT-2022B provide the two required channels for this function. However, only the level transmitter associated with the CST(s) required by LCO 3.7.6, "Condensate Storage Tank(s)" are required for this LCO.

13. Refueling Water Storage Tank (RWST) Level

RWST Level is a Type A variable provided for verifying a water source to the SI, RHR, and Containment Spray (CS) Systems.

(continued)

BASES

LCO

13. Refueling Water Storage Tank (RWST) Level (continued)

The RWST level accuracy is established to allow an adequate supply of water to the SI, RHR, and CS pumps during the switchover to the recirculation phase of an accident. A high degree of accuracy is required to maximize the time available to the operator to complete the switchover to the sump recirculation phase and ensure sufficient water is available to maintain adequate net positive suction head (NPSH) to operating pumps.

Level transmitters LT-920 and LT-921 provide the two required channels for this function.

14. RHR Flow

RHR Flow is a Type A variable provided for verifying low pressure safety injection to the reactor vessel and to the CS and SI pumps.

RHR flow is used to determine when to stop the RHR pumps and if sufficient flow is available to the CS and SI pumps during recirculation.

Since different flow transmitters are used to verify injection to the reactor vessel and to verify flow to the CS and SI pumps, FT-626 and FT-931A comprise one required channel and FT-689 and FT-931B comprise a second required channel.

(continued)

BASES

LCO

15, 16, 17, 18. (continued)

Core Exit Temperature

Core Exit Temperature is a Type A variable provided for verification and long term surveillance of core cooling.

An evaluation was made of the minimum number of valid CETs necessary for measuring core cooling. The evaluation determined the necessary complement of CETs required to detect initial core recovery and trend the ensuing core heatup. The evaluation accounted for core nonuniformities, including incore effects of the radial decay power distribution, excore effects of reflux in the hot legs, and nonuniform inlet temperatures. Based on these evaluations, adequate core cooling is ensured with two valid Core Exit Temperature channels per quadrant with two CETs per required channel.

Core Exit Temperature is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Core Exit Temperature is also used for plant stabilization and cooldown control.

Two OPERABLE channels of Core Exit Temperature are required in each quadrant to provide indication of radial distribution of the coolant temperature rise across representative regions of the core. Because of the small core size, two randomly selected thermocouples are sufficient to meet the two thermocouples per channel requirement in any quadrant. However, a CET which lies directly on the dividing line between two quadrants can only be used to satisfy the minimum required channels for one quadrant.

A CET is considered OPERABLE when it is within ± 35°F of the average CET reading except for the CETs associated with peripheral assemblies. These CETs (A7, B5, C3, C.11, D2, D12, H13, I2, K3, K11, L10, and M6) are considered OPERABLE when they are within ± 43°F of the average CET reading. At least two CETs from each of the following trains must be OPERABLE in each of the four quadrants:

(continued)

BASES

LCO

15, 16, 17, 18. Core Exit Temperature (continued)

Train A CET	Train A Location	Train B CET	Train B Location
T2	M6	T1	I4
T5	J3	T3	L7
T6	I2	T4	K3
T7	J6	T10	J9
T8	L10	T13	K11
T9	J8	T14	D12
T12	H6	T16	H10
T15	H9	T17	E10
T18	F8	T19	G7
T21	C11	T20	C8
T22	H11	T24	F12
T23	H13	T25	G12
T26*	I10	T27	E6
T28	D5	T29	E4
T33	D2	T30*	G4
T34	C3	T31	G2
T36	B7	T32*	G1
T38	B5	T35	A7
T39	D7	T37	C6

* - These thermocouples are in the reactor vessel head and cannot be credited with respect to this LCO.

19, 20. AFW Flow

AFW Flow is a Type A variable provided to monitor operation of the preferred AFW system.

(continued)

BASES

LCO 19, 20. AFW Flow (continued)

The AFW System provides decay heat removal via the SGs and is comprised of the preferred AFW System and the Standby AFW (SAFW) System. The use of the preferred AFW or SAFW System to provide this decay heat removal function is dependent upon the type of accident. AFW flow indication is required from the three pump trains which comprise the preferred AFW System since these pumps automatically start on various actuation signals. The failure of the preferred AFW System (e.g., due to a high energy line break (HELB) in the Intermediate Building) is detected by AFW flow indication. At this point, the SAFW System is manually aligned to provide the decay heat removal function.

SAFW flow can also be used to verify that AFW flow is being delivered to the SGs. However, the primary indication of this is provided by SG water level. Therefore, flow indication from the SAFW pumps is not required.

Each of the three preferred AFW pump trains has two redundant transmitters; however, only the flow transmitter supplied power from the same electrical train as the AFW pump is required for this LCO. Therefore, flow transmitters FT-2001 (MCB indicator FI-2021A) and FT-2007 (MCB indicator FI-2024A) comprise the two required channels for SG A and FT-2002 (MCB indicator FI-2022A) and FT-2006 (MCB indicator FI-2023A) comprise the two required channels for SG B.

(continued)

BASES

LCO
21, 22, 23, 24. (continued)

SG Water Level (Narrow and Wide Range)

SG Water Level is a Type A variable provided to monitor operation of decay heat removal via the SGs. For the narrow range level, the signals from the transmitters are independently indicated on the main control board as 0% to 100%. This corresponds to approximately above the top of the tube bundles to the top of the swirl vane separators (span of 143 inches). For the wide range level, signals from the transmitters are indicated as 0 to 520 inches (0% to 100%) on the main control board.

SG Water Level (Narrow and Wide Range) is used to:

- identify the faulted SG following a tube rupture;
- verify that the intact SGs are an adequate heat sink for the reactor;
- determine the nature of the accident in progress (e.g., verify an SGTR); and
- verify plant conditions for termination of SI during secondary plant HELBs outside containment.

Redundant monitoring capability is provided by two trains of instrumentation per SG.

SG Water Level (Narrow Range) requires 2 channels of indication per SG. This can be met using any of the following combinations of level transmitters for SG A:

- LT-461 and LT-462;
- LT-462 and LT-463; or
- LT-461 and LT-463;

(continued)

BASES

LCO

21, 22, 23, 24. <u>SG Water Level (Narrow and Wide Range)</u> (continued)

For SG B, any of the following combinations of level transmitters can be used:

- LT-471 and LT-473;
- LT-471 and LT-472; or
- LT-472 and LT-473.

The loss of Instrument Bus D requires declaring LT-463 and LT-471 inoperable.

SG Water Level (Wide Range) requires 2 channels of indication per SG. Two channels per SG are required since the loss of one channel with no backup available may result in the complete loss of information required by the operators to accomplish necessary safety functions. Level transmitters LT-504 and LT-505 comprise the two required channels for SG A and LT-506 and LT-507 comprise the two required channels for SG B.

25, 26. <u>SG Pressure</u>

SG Pressure is a Type A variable provided to monitor operation of decay heat removal via the SGs. The signals from the transmitters are calibrated for a range of 0 psig to 1400 psig. Redundant monitoring capability is provided by three available trains of instrumentation.

Any of the following combinations of pressure transmitters comprise the two required channels for SG A:

- PT-468 and PT-482; or
- PT-469 and PT-482.

(continued)

BASES

LCO 25 and 26. SG Pressure (continued)

Any of the following combinations of pressure transmitters comprise the two required channels for SG B:

- PT-479 and PT-478; or
- PT-478 and PT-483.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and pre-planned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, the PAM instrumentation is not required to be OPERABLE because plant conditions are such that the likelihood of an event that would require PAM instrumentation is low.

ACTIONS

The ACTIONS are modified by two Notes.

Note 1 has been added to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to respond to an accident using alternate instruments and methods, and the low probability of an event requiring these instruments.

Note 2 has been added to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

(continued)

BASES

ACTIONS (continued)

A.1

Condition A applies when one or more Functions have one required channel that is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel, the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM Instrumentation during this interval.

Condition A is modified by a Note which states that the Condition is not applicable to Table 3.3.3-1 Functions 3 and 4. These Functions are addressed by Condition C which provides the necessary required actions for these single channel Functions.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A is not met. This Condition requires the immediate initiation of actions to prepare and submit a special report to the NRC. This report shall be submitted within the following 14 days from the time the Condition is entered. This report shall discuss the results of the root cause evaluation of the inoperability and identify proposed restorative actions or alternate means of providing the required function. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of plant conditions that would require information provided by this instrumentation. If alternate means are to be used, they must be developed and tested prior to submittal of the special report.

(continued)

BASES

ACTIONS (continued)

C.1

Condition C applies when a Function has one inoperable required channel and no diverse channel OPERABLE (i.e., loss of RCS Hot Leg Temperature or RCS Cold Leg Temperature Functions). This Condition requires restoring the inoperable channel in the affected Function to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with a complete loss of function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of the inoperable channel limits the risk that the PAM Function will be in a degraded condition should an accident occur.

Condition C is modified by a Note which states that this Condition is only applicable to Table 3.3.3-1 Functions 3 and 4. All remaining Functions are addressed by Condition A with one channel inoperable.

D.1

Condition D applies when one or more Functions have two inoperable required channels (i.e., two channels inoperable in the same Function). Required Action D.1 requires restoring one channel in the Function(s) to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur. Condition D is modified by a Note that excludes Function 11 since the inoperability of two hydrogen monitor channels is addressed by Condition E.

(continued)

BASES

ACTIONS (continued)

E.1

Condition E applies when two hydrogen monitor channels are inoperable. This Condition requires restoring one hydrogen monitor channel to OPERABLE status within 72 hours. The 72 hour Completion Time is reasonable based on the backup capability of the Post Accident Sampling System to monitor the hydrogen concentration for evaluation of core damage and to provide information for operator decisions. Also, it is unlikely that a LOCA which would potentially require use of the hydrogen recombiners would occur during this time.

F.1

Condition F applies when the Required Action and associated Completion Time of Condition C, D, or E are not met. Required Action F.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C, D, or E, and the associated Completion Time has expired, Condition F is entered for that channel and provides for transfer to the appropriate subsequent Condition.

G.1 and G.2

If one channel for Function 3 and 4 cannot be restored to OPERABLE status within the required Completion Time for Condition C, if one channel for Function 1, 2, 3, 4, 5, 6, 8, 9, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, or 26 cannot be restored to OPERABLE status within the required Completion Time of Condition D, or if one channel for Function 11 cannot be restored to OPERABLE status within the required Completion Time of Condition E, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

H.1

If one channel for Function 7 or 10 cannot be restored to OPERABLE status within the required Completion Time of Condition D, the plant must take immediate action to prepare and submit a special report to the NRC. This report shall be submitted within the following 14 days from the time the action is required. This report discusses the alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation, the degree to which the alternate means are equivalent to the installed PAM channels, the areas in which they are not equivalent, and a schedule for restoring the normal PAM channels.

These alternate means must have been developed and tested and may be temporarily installed if the normal PAM channel(s) cannot be restored to OPERABLE status within the allotted time.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of more serious instrument conditions. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar plant instruments located throughout the plant.

(continued)

BASES

SURVEILLANCE

SR 3.3.3.1 (continued)

Channel check acceptance criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.3.2

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to the measured parameter with the necessary range and accuracy. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the Core Exit thermocouple sensors shall include an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. This is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

REFERENCES

1. UFSAR, Section 7.5.2.
2. Regulatory Guide 1.97, Rev. 3.
3. NUREG-0737, Supplement 1, "TMI Action Items."

B 3.3 INSTRUMENTATION

B 3.3.4 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe plant operation. The LOP DG start instrumentation consists of two channels on each of safeguards Buses 14, 16, 17, and 18 (Ref. 1). Each channel contains one loss of voltage relay and one degraded voltage relay (see Figure B 3.3.4-1). A one-out-of-two logic in both channels will cause the following actions on the associated safeguards bus:

a. trip of the normal feed breaker from offsite power;

b. trip of the bus-tie breaker to the opposite electrical train (if closed);

c. shed of all bus loads except the CS pump, component cooling water pump (if no safety injection signal is present), and safety related motor control centers; and

d. start of the associated DG.

The degraded voltage logic is provided on each 480 V safeguards bus to protect Engineered Safety Features (ESF) components from exposure to long periods of reduced voltage conditions which can result in degraded performance and to ensure that required motors can start. The loss of voltage logic is provided on each 480 V safeguards bus to ensure the DG is started within the time limits assumed in the accident analysis to provide the required electrical power if offsite power is lost.

The degraded voltage relays have time delays which have inverse operating characteristics such that the lower the bus voltage, the faster the operating time. The loss of voltage relays have definite time delays which are not related to the rate of the loss of bus voltage. These time delays are set to permit voltage transients during worst case motor starting conditions.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the ESF Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS). Undervoltage conditions which occur independent of any accident conditions result in the start and bus connection of the associated DG, but no automatic loading occurs.

Accident analyses credit the loading of the DG based on the loss of offsite power during a Design Basis Accident (DBA). The most limiting DBA of concern is the large break loss of coolant accident (LOCA) which requires ESF Systems in order to maintain containment integrity and protect fuel contained within the reactor vessel (Ref. 2). The detection and processing of an undervoltage condition, and subsequent DG loading, has been included in the delay time assumed for each ESF component requiring DG supplied power following a DBA and loss of offsite power.

The loss of offsite power has been assumed to occur either coincident with the DBA or at a later period (40 to 90 seconds following the reactor trip) due to a grid disturbance caused by the turbine generator trip. If the loss of offsite power occurs at the same time as the safety injection (SI) signal parameters are reached, the accident analyses assumes the SI signal will actuate the DG within 2 seconds and that the DG will connect to the affected safeguards bus within an additional 10 seconds (12 seconds total time). If the loss of offsite power occurs before the SI signal parameters are reached, the accident analyses assumes the LOP DG start instrumentation will actuate the DG within 2.75 seconds and that the DG will connect to the affected safeguards bus within an additional 10 seconds (12.75 seconds total time). If the loss of offsite power occurs after the SI signal parameters are reached (grid disturbance), the accident analyses assumes the LOP DG start instrumentation will open the feeder breaker to the affected bus within 2.75 seconds and the DG will connect to the bus within an additional 1.5 seconds (DG was actuated by SI signal). The grid disturbance has been evaluated based on a 140°F peak clad temperature penalty during a LOCA and demonstrated to result in acceptable consequences.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The degraded voltage and undervoltage setpoints are based on the minimum voltage required for continued operation of ESF Systems assuming worst case loading conditions (i.e., maximum loading upon DG sequencing). The Trip Setpoint for the loss of voltage relays, and associated time delays, have been chosen based on the following considerations:

a. Actuate the associated DG within 2.75 seconds as assumed in the accident analysis; and

b. Prevent DG actuation on momentary voltage drops associated with starting of ESF components during an accident with offsite power available and during normal operation due to minor system disturbances. Therefore, the time delay setting must be greater than the time between the largest assumed voltage drop below the voltage setting and the reset value of the trip function.

The Trip Setpoint for the degraded voltage channels, and associated time delays, have been chosen based on the following considerations;

a. Prevent motors supplied by the 480 V bus from operating at reduced voltage conditions for long periods of time; and

b. Prevent DG actuation on momentary voltage drops associated with starting of ESF components during an accident with offsite power available, and during normal operation due to minor system disturbances. Therefore, the time delay setting must be greater than the time between the largest voltage drop below the maximum voltage setting and the reset value of the trip function.

The LOP DG start instrumentation channels satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

This LCO requires that each 480 V safeguards bus have two OPERABLE channels of the LOP DG start instrumentation in MODES 1, 2, 3, and 4 when the associated DG supports safety systems associated with the ESFAS. In MODES 5 and 6, the LOP DG start instrumentation channels for each 480 V safeguards bus must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed. Loss of the LOP DG Start Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents.

The LOP start instrumentation is considered OPERABLE when two channels, each comprised of one degraded voltage and one loss of voltage relays are available for each 480 V safeguards bus (i.e., Bus 14, 16, 17, and 18). Each of the LOP channels must be capable of detecting undervoltage conditions within the voltage limits and time delays assumed in the accident analysis.

The Allowable Values and Trip Setpoints for the degraded voltage and loss of voltage Functions are specified in SR 3.3.4.2. The Allowable Values specified in SR 3.3.4.2 are those setpoints which ensure that the associated DG will actuate within 2.75 seconds on undervoltage conditions, and that the DG will not actuate on momentary voltage drops which could affect ESF actuation times as assumed in the accident analysis. The Trip Setpoints specified in SR 3.3.4.2 are the nominal setpoints selected to ensure that the setpoint measured by the Surveillance does not exceed the Allowable Value accounting for maximum instrument uncertainties between scheduled surveillances. Therefore, LOP start instrumentation channels are OPERABLE when the CHANNEL CALIBRATION "as left" value is within the Trip Setpoint limits and the CHANNEL CALIBRATION and TADOT "as found" value is within the Allowed Value setpoints. The basis for all setpoints is contained in Reference 3.

(continued)

BASES (continued)

APPLICABILITY

The LOP DG Start Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE so that it can perform its function on an LOP or degraded power to the 480 V safeguards buses.

ACTIONS

In the event a relay's Trip Setpoint is found to be nonconservative with respect to the Allowable Value, or the channel is found to be inoperable, then the channel must be declared inoperable and the LCO Condition entered as applicable.

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. This Note states that separate Condition entry is allowed for each 480 V safeguards bus.

A.1

With one or more 480 V bus(es) with one channel inoperable, Required Action A.1 requires the inoperable channel(s) to be placed in trip within 6 hours. With an undervoltage channel in the tripped condition, the LOP DG start instrumentation channels are configured to provide a one-out-of-one logic to initiate a trip of the incoming offsite power for the respective bus. The remaining OPERABLE channel is comprised of one-out-of-two logic from the degraded and loss of voltage relays. Any additional failure of either of these two OPERABLE relays requires entry into Condition B.

(continued)

BASES

ACTIONS (continued)

B.1

Condition B applies to the LOP DG start Function when the Required Action and associated Completion Time for Condition A are not met or with one or more 480 V bus(es) with two channels of LOP start instrumentation inoperable.

Condition B requires immediate entry into the Applicable Conditions specified in LCO 3.8.1, "AC Sources — MODES 1, 2, 3, and 4," or LCO 3.8.2, "AC Sources — MODES 5 and 6," for the DG made inoperable by failure of the LOP DG start instrumentation. The actions of those LCOs provide for adequate compensatory actions to assure plant safety.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that, when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 4 hours, provided the second channel maintains trip capability. Upon completion of the Surveillance, or expiration of the 4 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the assumption that 4 hours is the average time required to perform channel surveillance. Based on engineering judgement, the 4 hour testing allowance does not significantly reduce the probability that the LOP DG start instrumentation will trip when necessary.

SR 3.3.4.1

This SR is the performance of a TADOT every 31 days. This test checks trip devices that provide actuation signals directly. For these tests, the relay Trip Setpoints are verified and adjusted as necessary to ensure Allowable Values can still be met. The 31 day Frequency is based on the known reliability of the relays and controls and has been shown to be acceptable through operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.2

This SR is the performance of a CHANNEL CALIBRATION every 24 months, or approximately at every refueling of the LOP DG start instrumentation for each 480 V bus.

The voltage setpoint verification, as well as the time response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay.

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency of 24 months is based on operating experience consistent with the typical industry refueling cycle and is justified by the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. UFSAR, Section 8.3.
2. UFSAR, Chapter 15.
3. RG&E Design Analysis DA-EE-93-006-08, "480 Volt Undervoltage Relay Settings and Test Acceptance Criteria."

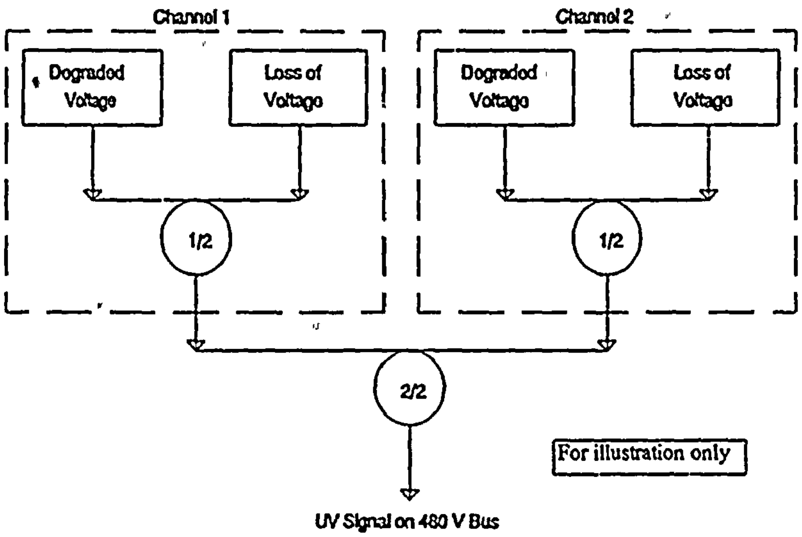


Figure B 3.3.4-1
DG LOP Instrumentation

B 3.3 INSTRUMENTATION

B 3.3.5 Containment Ventilation Isolation Instrumentation

BASES

BACKGROUND

Containment ventilation isolation instrumentation closes the containment isolation valves in the Mini-Purge System and the Shutdown Purge System. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. The Mini-Purge System may be used in all MODES while the Shutdown Purge System may only be used with the reactor shutdown.

Containment ventilation isolation initiates on a containment isolation signal, containment radiation signal, or by manual actuation of containment spray (CS). The Bases for LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," discuss the containment isolation and manual containment spray modes of initiation.

Two containment radiation monitoring channels are provided as input to the containment ventilation isolation. The two radiation detectors are of different types: gaseous (R-12), and particulate (R-11). Both detectors will respond to most events that release radiation to containment. However, analyses have not been conducted to demonstrate that all credible events will be detected by more than one monitor. Therefore, for the purposes of this LCO the two channels are not considered redundant. Instead, they are treated as two one-out-of-one Functions. Since the radiation monitors constitute a sampling system, various components such as sample line valves, sample line heaters, sample pumps, and filter motors are required to support monitor OPERABILITY.

(continued)

BASES

BACKGROUND (continued)

The Mini-Purge System has inner and outer containment isolation valves in its supply and exhaust ducts while the Shutdown Purge System only has one valve located outside containment since the inside valve was replaced by a blind flange that is used during MODES 1, 2, 3, and 4. A high radiation signal from any one of the two channels initiates containment ventilation isolation, which closes all isolation valves in the Mini-Purge System and the Shutdown Purge System. These systems are described in the Bases for LCO 3.6.3, "Containment Isolation Boundaries."

APPLICABLE SAFETY ANALYSES

The safety analyses assume that the containment remains intact with penetrations unnecessary for accident mitigation functions isolated early in the event, within approximately 60 seconds. The isolation of the purge valves has not been analyzed mechanistically in the dose calculations, although its rapid isolation is assumed. The containment ventilation isolation radiation monitors act as backup to the containment isolation signal to ensure closing of the ventilation valves. They are also the primary means for automatically isolating containment in the event of a fuel handling accident during shutdown even though containment isolation is not specifically credited for this event. Containment isolation in turn ensures meeting the containment leakage rate assumptions of the safety analyses, and ensures that the calculated accident offsite radiological doses are below 10 CFR 100 (Ref. 1) limits.

The containment ventilation isolation instrumentation satisfies Criterion 3 of the NRC Policy Statement.

LCO

The LCO requirements ensure that the instrumentation necessary to initiate Containment Ventilation Isolation, listed in Table 3.3.5-1, is OPERABLE.

(continued)

BASES

LCO (continued)

1. Automatic Actuation Logic and Actuation Relays

The LCO requires two trains of Automatic Actuation Logic and Actuation Relays OPERABLE to ensure that no single random failure can prevent automatic actuation.

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 2.b, Containment Spray - Manual Initiation, and ESFAS Function 3, Containment Isolation. The applicable MODES and specified conditions for the containment ventilation isolation portion of these Functions are different and less restrictive than those for their respective CS and ESFAS roles. If one or more of the CS or containment isolation Functions becomes inoperable in such a manner that only the Containment Ventilation Isolation Function is affected, the Conditions applicable to their respective isolation Functions in LCO 3.3.2 need not be entered. The less restrictive Actions specified for inoperability of the Containment Ventilation Isolation Functions specify sufficient compensatory measures for this case.

2. Containment Radiation

The LCO specifies two required channels of radiation monitors (R-11 and R-12) to ensure that the radiation monitoring instrumentation necessary to initiate Containment Ventilation Isolation remains OPERABLE.

For sampling systems, channel OPERABILITY involves more than OPERABILITY of the channel electronics. OPERABILITY may also require correct valve lineups, sample pump operation, and filter motor operation, as well as detector OPERABILITY, if these supporting features are necessary for trip to occur.

3. Containment Isolation

Refer to LCO 3.3.2, Function 3, for all initiating Functions and requirements.

(continued)

BASES

LCO (continued)

4. Containment Spray - Manual Initiation

Refer to LCO 3.3.2, Function 2.a, for all initiating Functions and requirements. This Function provides the manual initiation capability for containment ventilation isolation.

APPLICABILITY

The Automatic Actuation Logic and Actuation Relays, Containment Isolation, Containment Spray - Manual Initiation, and Containment Radiation Functions are required OPERABLE in MODES 1, 2, 3, and 4, and during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. Under these conditions, the potential exists for an accident that could release fission product radioactivity into containment. Therefore, the containment ventilation isolation instrumentation must be OPERABLE in these MODES.

While in MODES 5 and 6 without fuel handling in progress, the containment ventilation isolation instrumentation need not be OPERABLE since the potential for radioactive releases is minimized and operator action is sufficient to ensure post accident offsite doses are maintained within the limits of Reference 1.

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by plant specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

(continued)

BASES

ACTIONS (continued)

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.5-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the failure of one containment ventilation isolation radiation monitor channel. Since the two containment radiation monitors measure different parameters, failure of a single channel may result in loss of the radiation monitoring Function for certain events. Consequently, the failed channel must be restored to OPERABLE status. The 4 hour allowed to restore the affected channel is justified by the low likelihood of events occurring during this interval, and recognition that one or more of the remaining channels will respond to most events.

B.1

Condition B applies to all Containment Ventilation Isolation Functions and addresses the train orientation of the system and the master and slave relays for these Functions. It also addresses the failure of multiple radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1.

If a train is inoperable, multiple channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action for the applicable Conditions of LCO 3.6.3 is met for each valve made inoperable by failure of isolation instrumentation.

A Note is added stating that Condition B is only applicable in MODE 1, 2, 3, or 4.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Condition C applies to all Containment Ventilation Isolation Functions and addresses the train orientation of the system and the master and slave relays for these Functions. It also addresses the failure of multiple radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1.

If a train is inoperable, multiple channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action to place each valve in its closed position or the applicable Conditions of LCO 3.9.3, "Containment Penetrations," are met for each valve made inoperable by failure of isolation instrumentation. The Completion Time for these Required Actions is Immediately.

A Note states that Condition C is applicable during CORE ALTERATIONS and during movement of irradiated fuel assemblies within containment.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.5-1 determines which SRs apply to which Containment Ventilation Isolation Functions.

SR 3.3.5.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1 (continued)

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.5.2

A COT is performed every 92 days on each required channel to ensure the entire channel will perform the intended Function. The Frequency is based on the staff recommendation for increasing the availability of radiation monitors according to NUREG-1366 (Ref. 2). This test verifies the capability of the instrumentation to provide the containment ventilation system isolation. The setpoint shall be left consistent with the current plant specific calibration procedure tolerance.

SR 3.3.5.3

This SR is the performance of an ACTUATION LOGIC TEST. All possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay is tested for continuity. This verifies that the logic modules are OPERABLE and there is an intact voltage signal path to the master relay coils. This test is performed every 24 months. The Surveillance interval is acceptable based on instrument reliability and industry operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.4

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

REFERENCES

1. 10 CFR 100.11.

2. NUREG-1366.

B 3.3 INSTRUMENTATION

B 3.3.6 Control Room Emergency Air Treatment System (CREATS) Actuation Instrumentation

BASES

BACKGROUND

The CREATS provides a protected environment from which operators can control the plant following an uncontrolled release of radioactivity. This system is described in the Bases for LCO 3.7.9, "Control Room Emergency Air Treatment System (CREATS)." This LCO only addresses the actuation instrumentation for the high radiation state CREATS Mode F.

The high radiation state CREATS Mode F actuation instrumentation consists of noble gas (R-36), particulate (R-37), and iodine (R-38) radiation monitors. These detectors are located on the operating level on the Turbine Building and utilize a common air supply pump. A high radiation signal from any of these detectors will initiate the CREATS filtration train and isolate each air supply path with two dampers. The control room operator can also initiate the CREATS filtration train and isolate the air supply paths by using a manual pushbutton in the control room.

APPLICABLE SAFETY ANALYSES

The location of components and CREATS related ducting within the control room envelope ensures an adequate supply of filtered air to all areas requiring access. The CREATS provides airborne radiological protection for the control room operators in MODES 1, 2, 3, and 4, as demonstrated by the control room accident dose analyses for the most limiting design basis loss of coolant accident and steam generator tube rupture (Ref. 1). This analysis shows that with credit for the CREATS, or with credit for instantaneous isolation of the control room coincident with the accident initiator and no CREATS filtration train available, the dose rates to control room personnel remain within GDC 19 limits.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

In MODES 5 and 6, and during movement of irradiated fuel assemblies, the CREATS ensures control room habitability in the event of a fuel handling accident or waste gas decay tank rupture accident.

The CREATS Actuation Instrumentation satisfies Criterion 3 of the NRC Policy Statement.

LCO

The LCO requirements ensure that instrumentation necessary to initiate the CREATS is OPERABLE.

1. Manual Initiation

   The LCO requires one train to be OPERABLE. The train consists of one pushbutton and the interconnecting wiring to the actuation logic. The operator can initiate the CREATS Filtration train at any time by using a pushbutton in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals required by this LCO.

2. Automatic Actuation Logic and Actuation Relays

   The LCO requires one train of Actuation Logic and Actuation Relays to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation system, including the initiation relay contacts responsible for actuating the CREATS.

3. Control Room Radiation Intake Monitor

   The LCO specifies single channels of iodine (R-38), noble gas (R-36), and particulate (R-37) of the Control Room Intake Monitors to ensure that the radiation monitoring instrumentation necessary to initiate the CREATS filtration train and isolation dampers remains OPERABLE.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, the CREATS actuation instrumentation must be OPERABLE to control operator exposure during and following a Design Basis Accident.

In MODE 5 or 6, the CREATS actuation instrumentation is required to cope with the release from the rupture of a waste gas decay tank.

During movement of irradiated fuel assemblies, the CREATS actuation instrumentation must be OPERABLE to cope with the release from a fuel handling accident.

ACTIONS

The most common cause of channel inoperability is failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by the plant specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification. The "as left" Trip Setpoint must be within the tolerance specified by the calibration procedure. If the "as found" Trip Setpoint exceeds the limits specified in Table 3.3.6-1, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.6-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel/train of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

(continued)

BASES

ACTIONS (continued)

A.1

Condition A applies to one or more Functions with one channel of the CREATS actuation instrumentation inoperable.

If one or more radiation monitor channels, the manual initiation train, or the automatic actuation logic train is inoperable, action must be taken to restore OPERABLE status within 1 hour or isolate the control room from outside air. In this Condition for the manual initiation train inoperable or a radiation monitor channel inoperable, the remaining CREATS actuation instrumentation is adequate to perform the control room protection function but the actuation time or responsiveness of the CREATS may be affected. In this Condition for the automatic actuation logic train inoperable or all radiation monitor channels inoperable, the CREATS is not capable of performing its intended automatic function. This is considered a loss of safety function. The CREATS, however, may still be capable of being placed in CREATS Mode F by manual operator actions. The 1 hour Completion Time is based on the low probability of a DBA occurring during this time frame, and the ability of the CREATS dampers to automatically isolate the control room or be manually isolated by the operator.

The Required Action for Condition A is modified by a Note which allows the control room to be unisolated for ≤ 1 hour every 24 hours. This allows fresh air makeup to improve the working environment within the control room and is acceptable based on the low probability of a DBA occurring during this makeup period.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

Condition B applies when the Required Action and associated Completion Time of Condition A has not been met and the plant is in MODE 1, 2, 3, or 4. The plant must be brought to a MODE that minimizes accident risk. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1, C.2, and C.3

Condition C applies when the Required Action and associated Completion Time of Condition A has not been met in MODE 5, or 6, or during movement of irradiated fuel assemblies. Actions must be initiated immediately to restore the inoperable channel(s) to OPERABLE status to ensure adequate isolation capability in the event of a waste gas decay tank rupture. Movement of irradiated fuel assemblies and CORE ALTERATIONS must also be suspended immediately to reduce the risk of accidents that would require CREATS actuation. This places the plant in a condition that minimizes risk. This does not preclude movement of fuel or other components to a safe position.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.6-1 determines which SRs apply to which CREATS Actuation Functions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1

This SR is the performance of a COT once every 92 days on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the automatic CREATS actuation. The setpoints shall be left consistent with the plant specific calibration procedure tolerance. The Frequency of 92 days is based on the known reliability of the monitoring equipment and has been shown to be acceptable through operating experience.

SR 3.3.6.2

This SR is the performance of a TADOT of the Manual Actuation Functions every 24 months. The Manual Actuation Function is tested up to, and including, the master relay coils.

The Frequency of 24 months is based on the known reliability of the Function and the redundancy available, and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of setpoints because the Manual Initiation Function has no setpoints associated with them.

SR 3.3.6.3

This SR is the performance of a CHANNEL CALIBRATION every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency of 24 months is based on operating experience and is consistent with the typical industry refueling cycle.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.4

This SR is the performance of an ACTUATION LOGIC TEST. All possible logic combinations are tested for the CREATS actuation instrumentation. In addition, the master relay is tested for continuity. This verifies that the logic modules are OPERABLE and there is an intact voltage signal path to the master relay coils. This test is acceptable based on instrument reliability and operating experience.

REFERENCES

1. UFSAR, Section 6.4.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be withjn the limits specified in the COLR.

-------------------------NOTE---------------------------
Pressurizer pressure limit does not apply during pressure transients due to:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

APPLICABILITY: MODE 1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1 Restore RCS DNB parameter(s) to within limit.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is within limit specified in the COLR.	12 hours
SR 3.4.1.2	Verify RCS average temperature is within limit specified in the COLR.	12 hours
SR 3.4.1.3	-------------------NOTE-------------------- Required to be performed within 7 days after ≥ 95% RTP. -- Verify RCS total flow rate is within the limit specified in the COLR.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 RCS Minimum Temperature for Criticality

LCO 3.4.2 Each RCS loop average temperature (T_{avg}) shall be ≥ 540°F.

APPLICABILITY: MODE 1,
MODE 2 with k_{eff} ≥ 1.0.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. T_{avg} in one or both RCS loops not within limit.	A.1 Be in MODE 2 with K_{eff} < 1.0.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	Verify RCS T_{avg} in each loop ≥ 540°F.	Within 30 minutes prior to achieving criticality.
SR 3.4.2.2	-------------------NOTE------------------- Only required if any RCS loop T_{avg} < 547°F and the low T_{avg} alarm is either inoperable or not reset. -- Verify RCS T_{avg} in each loop ≥ 540°F.	Once within 30 minutes and every 30 minutes thereafter

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.3 RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ---------NOTE--------- Required Action A.2 shall be completed whenever this Condition is entered. ---------------------- Requirements of LCO not met in MODE 1, 2, 3, or 4.	A.1 Restore parameter(s) to within limits. AND A.2 Determine RCS is acceptable for continued operation.	30 minutes 72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5 with RCS pressure < 500 psig.	6 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. ---------NOTE--------- Required Action C.2 shall be completed whenever this Condition is entered. --------------------- Requirements of LCO not met any time in other than MODE 1, 2, 3, or 4.	C.1	Initiate action to restore parameter(s) to within limits.	Immediately
	AND		
	C.2	Determine RCS is acceptable for continued operation.	Prior to entering MODE 4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	------------------NOTE------------------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. --	
	Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	30 minutes

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Loops — MODE 1 > 8.5% RTP

LCO 3.4.4 Two RCS loops shall be OPERABLE and in operation.

APPLICABILITY: MODE 1 > 8.5% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of LCO not met.	A.1 Be in MODE 1 ≤ 8.5% RTP.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.4.1 Verify each RCS loop is in operation.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 RCS Loops — MODES 1 ≤ 8.5% RTP, 2, and 3

LCO 3.4.5 Two RCS loops shall be OPERABLE and one loop shall be in operation.

---------------------------NOTE---------------------------
Both reactor coolant pumps may be de-energized in MODE 3 for ≤ 1 hour per 8 hour period provided:

a. No operations are permitted that would cause reduction of the RCS boron concentration; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature.

APPLICABILITY: MODES 1 ≤ 8.5% RTP,
MODES 2 and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RCS loop inoperable.	-------------NOTE------------ LCO 3.0.4 is not applicable. ----------------------------- A.1 Verify SDM is within limits specified in the COLR. AND A.2 Restore inoperable RCS loop to OPERABLE status.	 Once per 12 hours 72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 4.	12 hours
C. Both RCS loops inoperable. OR No RCS loop in operation.	C.1 De-energize all CRDMs. AND C.2 Suspend all operations involving a reduction of RCS boron concentration. AND C.3 Initiate action to restore one RCS loop to OPERABLE status and operation.	Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify required RCS loop is in operation.	12 hours
SR 3.4.5.2	Verify steam generator secondary side water levels are ≥ 16% for two RCS loops.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required RCP that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 RCS Loops — MODE 4

LCO 3.4.6 Two loops consisting of any combination of RCS loops and residual heat removal (RHR) loops shall be OPERABLE, and one loop shall be in operation.

---------------------------NOTES---------------------------

1. All reactor coolant pumps (RCPs) and RHR pumps may be de-energized for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause reduction of the RCS boron concentration; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. No RCP shall be started with any RCS cold leg temperature less than or equal to the LTOP enable temperature specified in the PTLR unless:

   a. The secondary side water temperature of each steam generator (SG) is ≤ 50°F above each of the RCS cold leg temperatures; or

   b. The pressurizer water volume is < 324 cubic feet (38% level).

APPLICABILITY: MODE 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RCS loop inoperable. AND Two RHR loops inoperable.	A.1 Initiate action to restore a second loop to OPERABLE status.	Immediately
B. One RHR loop inoperable. AND Two RCS loops inoperable.	-------------NOTE------------ Required Action B.1 is not applicable if all RCS and RHR loops are inoperable and Condition C is entered. ---------------------------- B.1 Be in MODE 5.	24 hours
C. All RCS and RHR loops inoperable. OR No RCS or RHR loop in operation.	C.1 Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND	
	C.2 Initiate action to restore one loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side water level is ≥ 16% for each required RCS loop.	12 hours
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops — MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least one steam generator (SG) shall be ≥ 16%.

-----------------------------NOTES-----------------------------

1. The RHR pump of the loop in operation may be de-energized for ≤ 1 hour per 8 hour period provided:

    a. No operations are permitted that would cause reduction of the RCS boron concentration; and

    b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with one or more RCS cold leg temperatures less than or equal to the LTOP enable temperature specified in the PTLR unless:

    a. The secondary side water temperature of each SG is ≤ 50°F above each of the RCS cold leg temperatures; or

    b. The pressurizer water volume is < 324 cubic feet (38% level).

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

APPLICABILITY: MODE 5 with RCS loops filled.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR loop inoperable. AND Both SGs secondary side water levels not within limits.	A.1 Initiate action to restore a second RHR loop to OPERABLE status. OR A.2 Initiate action to restore required SG secondary side water levels to within limits.	Immediately Immediately
B. Both RHR loops inoperable. OR No RHR loop in operation.	B.1 Suspend all operations involving a reduction of RCS boron concentration. AND B.2 Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.7.2	Verify SG secondary side water level is ≥ 16% in the required SG.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 RCS Loops — MODE 5, Loops Not Filled

LCO 3.4.8 Two residual heat removal (RHR) loops shall be OPERABLE and one RHR loop shall be in operation.

---------------------------NOTES---------------------------

1. All RHR pumps may be de-energized for ≤ 15 minutes when switching from one loop to another provided:

   a. No operations are permitted that would cause a reduction of the RCS boron concentration;

   b. Core outlet temperature is maintained at least 10°F below saturation temperature; and

   c. No draining operations to further reduce the RCS water volume are permitted.

2. One RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

APPLICABILITY: MODE 5 with RCS loops not filled.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR loop inoperable.	A.1 Initiate action to restore RHR loop to OPERABLE status.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Both RHR loops inoperable. OR No RHR loop in operation.	B.1 Suspend all operations involving reduction in RCS boron concentration. AND B.2 Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.8.2	Verify correct breaker alignment and indicated power are available to the RHR pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Pressurizer water level not within limit.	A.1 Be in MODE 3 with reactor trip breakers open. AND A.2 Be in MODE 4.	6 hours 12 hours
B. Pressurizer heaters capacity not within limits.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify pressurizer water level is ≤ 87%.	12 hours
SR 3.4.9.2	Verify total capacity of the pressurizer heaters is ≥ 100 Kw.	92 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Pressurizer Safety Valves

LCO 3.4.10 Two pressurizer safety valves shall be OPERABLE with lift settings ≥ 2410 psig and ≤ 2544 psig.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with all RCS cold leg temperatures greater than the LTOP enable temperature specified in the PTLR.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1	Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. OR Both pressurizer safety valves inoperable.	B.1 AND	Be in MODE 3.	6 hours
	B.2	Be in MODE 4 with any RCS cold leg temperature less than or equal to the LTOP enable temperature specified in the PTLR.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	--------------------NOTE------------------ Required to be performed within 36 hours of entering MODE 4 from MODE 5 with all RCS cold leg temperatures greater than the LTOP enable temperature specified in the PTLR for the purpose of setting the pressurizer safety valves under ambient (hot) conditions only provided a preliminary cold setting was made prior to heatup. -- Verify each pressurizer safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

LCO 3.4.11 Each PORV and associated block valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

-----NOTES-----

1. Separate entry into Condition A is allowed for each PORV.
2. Separate entry into Condition C is allowed for each block valve.
3. LCO 3.0.4 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or both PORVs OPERABLE and not capable of being automatically controlled.	A.1 Close and maintain power to associated block valve.	1 hour
	<u>OR</u>	
	A.2 Place associated PORV in manual control.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One PORV inoperable.	B.1	Close associated block valve.	1 hour
	<u>AND</u>		
	B.2	Remove power from associated block valve.	1 hour
	<u>AND</u>		
	B.3	Restore PORV to OPERABLE status.	72 hours
C. One block valve inoperable.	C.1	Place associated PORV in manual control.	1 hour
	<u>AND</u>		
	C.2	Restore block valve to OPERABLE status.	7 days
D. Both block valves inoperable.	D.1	Place associated PORVs in manual control.	1 hour
	<u>AND</u>		
	D.2	Restore at least one block valve to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1	Be in MODE 3.	6 hours
	AND		
	E.2	Be in MODE 4.	12 hours
F. Two PORVs inoperable.	F.1	Initiate action to restore one PORV to OPERABLE status.	Immediately
	AND		
	F.2	Close associated block valves.	1 hour
	AND		
	F.3	Remove power from associated block valves.	1 hour
	AND		
	F.4	Be in MODE 3 with T_{avg} < 500°F.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	-------------------NOTE------------------- Not required to be performed with block valve closed per LCO 3.4.13. -- Perform a complete cycle of each block valve.	92 days
SR 3.4.11.2	Perform a complete cycle of each PORV.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 Low Temperature Overpressure Protection (LTOP) System

LCO 3.4.12 An LTOP System shall be OPERABLE with the Emergency Core Cooling System (ECCS) accumulators isolated and either a or b below.

a. Two power operated relief valves (PORVs) with lift settings within the limits specified in the PTLR and no safety injection (SI) pump capable of injecting into the RCS.

b. The RCS depressurized and an RCS vent of ≥ 1.1 square inches and a maximum of one SI pump capable of injecting into the RCS.

---------------------------NOTES---------------------------

1. The PORVs and an RCS vent ≥ 1.1 square inches are not required to be OPERABLE during performance of the secondary side hydrostatic tests. However, no SI pump may be capable of injecting into the RCS during this test.

2. ECCS accumulator isolation is only required when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.

APPLICABILITY: MODE 4 when any RCS cold leg temperature is less than or equal to the LTOP enable temperature specified in the PTLR or when the RHR system is in the RHR mode of operation,
MODE 5 when the SG primary system manway and pressurizer manway are closed and secured in position,
MODE 6 when the reactor vessel head is on and the SG primary system manway and pressurizer manway are closed and secured in position.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. --------NOTE---------- Only applicable to LCO 3.4.12.a. ---------------------- One or more SI pumps capable of injecting into the RCS.	A.1	Initiate action to verify no SI pump is capable of injecting into the RCS.	Immediately
B. ----------NOTE-------- Only applicable to LCO 3.4.12.a. ---------------------- One required PORV inoperable in MODE 4.	B.1	Restore required PORV to OPERABLE status.	7 days
C. ----------NOTE-------- Only applicable to LCO 3.4.12.a. ---------------------- One required PORV inoperable in MODE 5 or MODE 6.	C.1	Restore required PORV to OPERABLE status.	72 hours
D. ----------NOTE-------- Only applicable to LCO 3.4.12.b. ---------------------- Two or more SI pumps capable of injecting into the RCS.	D.1	Initiate action to verify a maximum of one SI pump is capable of injecting into the RCS.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. An ECCS accumulator not isolated when the accumulator pressure is greater than or equal to the maximum RCS pressure for the existing cold leg temperature allowed in the PTLR.	E.1 Isolate affected ECCS accumulator.	1 hour
F. Required Action and associated Completion Time of Condition E not met.	F.1 Increase RCS cold leg temperature to greater than the LTOP enable temperature specified in the PTLR.	12 hours
	OR	
	F.2 Depressurize affected accumulator to less than the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Two required PORVs inoperable for LCO 3.4.12.a. OR Required Action and associated Completion Time of Condition A, B, C, or F not met. OR LTOP System inoperable for any reason other than Condition A, B, C, or E.	G.1 Verify at least one charging pump is in the pull-stop position. AND G.2 Depressurize RCS and establish RCS vent of $\geq$ 1.1 square inches.	1 hour 8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.12.1	------------------NOTE-------------------- Only required to be performed when complying with LCO 3.4.12.a. -- Verify no SI pump is capable of injecting into the RCS.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.2	-------------------NOTE------------------- Only required to be performed when complying with LCO 3.4.12.b. --- Verify a maximum of one SI pump is capable of injecting into the RCS.	12 hours
SR 3.4.12.3	-------------------NOTE------------------- Only required to be performed when ECCS accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR. --- Verify each ECCS accumulator motor operated isolation valve is closed.	Once within 12 hours and every 12 hours thereafter
SR 3.4.12.4	-------------------NOTE------------------- Only required to be performed when complying with LCO 3.4.12.b. --- Verify RCS vent ≥ 1.1 square inches open.	12 hours for unlocked open vent valve(s) <u>AND</u> 31 days for locked open vent valve(s)

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.5	Verify PORV block valve is open for each required PORV.	72 hours
SR 3.4.12.6	-------------------NOTE------------------- Required to be performed within 12 hours after decreasing RCS cold leg temperature to less than or equal to the LTOP enable temperature specified in the PTLR. -- Perform a COT on each required PORV, excluding actuation.	31 days
SR 3.4.12.7	-------------------NOTE------------------- Only required to be performed when ECCS accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR. -- Verify power is removed from each ECCS accumulator motor operated isolation valve operator.	Once within 12 hours and every 31 days thereafter
SR 3.4.12.8	Perform CHANNEL CALIBRATION for each required PORV actuation channel.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE; and

d. 0.1 gpm total primary to secondary LEAKAGE through each steam generator (SG) when averaged over 24 hours.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time not met. OR RCS pressure boundary LEAKAGE exists.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	-------------------NOTE-------------------- Only required to be performed during steady state operation. --- Perform RCS water inventory balance.	Once during initial 12 hours of steady state operation <u>AND</u> 72 hours thereafter
SR 3.4.13.2	Verify steam generator tube integrity is in accordance with the Steam Generator Tube Surveillance Program.	In accordance with the Steam Generator Tube Surveillance Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

LCO 3.4.14 Leakage from each RCS PIV shall be within limit.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-----------------------------------NOTES-----------------------------------

1. Separate Condition entry is allowed for each flow path.

2. Enter applicable Conditions and Required Actions for systems made inoperable by an inoperable PIV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more flowpaths with leakage from one or more RCS PIVs not within limit.	------------NOTE------------ Each valve used to satisfy Required Action A.1 and Required Action A.2 must have been verified to meet SR 3.4.14.1 or SR 3.4.14.2 and be in the reactor coolant pressure boundary or the high pressure portion of the system. ----------------------------	(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.1	Isolate the high pressure portion of the affected system from the low pressure portion by use of one closed manual, deactivated automatic, or check valve.	4 hours
	<u>AND</u>		
	A.2	Isolate the high pressure portion of the affected system from the low pressure portion by use of a second closed manual, deactivated automatic, or check valve.	72 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.14.1	-------------------NOTES------------------- 1. Not required to be performed until prior to entering MODE 2 from MODE 3. 2. RCS PIVs actuated during the performance of this Surveillance are not required to be tested more than once if a repetitive testing loop cannot be avoided. -- Verify leakage from each SI cold leg injection line and each RHR RCS PIV is equivalent to $\leq$ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at an RCS pressure $\geq$ 2215 psig and $\leq$ 2255 psig.	24 months <u>AND</u> Within 24 hours following valve actuation due to automatic or manual action, flow through the valve, or maintenance on the valve

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.14.2	-------------------NOTES------------------ 1. Not required to be performed until prior to entering MODE 2 from MODE 3. 2. RCS PIVs actuated during the performance of this Surveillance are not required to be tested more than once if a repetitive testing loop cannot be avoided. --	
	Verify leakage from each SI hot leg injection line RCS PIV is equivalent to ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at an RCS pressure ≥ 2215 psig and ≤ 2255 psig.	40 months <u>AND</u> Within 24 hours following valve actuation due to automatic or manual action, flow through the valve, or maintenance on the valve

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.15 RCS Leakage Detection Instrumentation

LCO 3.4.15 The following RCS leakage detection instrumentation shall be OPERABLE:

a. One containment sump A monitor (level or pump actuation); and

b. One containment atmosphere radioactivity monitor (gaseous or particulate).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required containment sump monitor inoperable.	------------NOTE------------ LCO 3.0.4 is not applicable. ------------------------------	
	A.1.1 Perform SR 3.4.13.1.	Once per 24 hours
	OR	
	A.1.2 Verify containment air cooler condensate collection system is OPERABLE.	24 hours
	AND	
	A.2 Restore required containment sump monitor to OPERABLE status.	30 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required containment atmosphere radioactivity monitor inoperable.	------------NOTE------------ LCO 3.0.4 is not applicable. ----------------------------	
	B.1.1 Analyze grab samples of the containment atmosphere.	Once per 24 hours
	<u>OR</u>	
	B.1.2 Perform SR 3.4.13.1.	Once per 24 hours
	<u>AND</u>	
	B.2 Restore required containment atmosphere radioactivity monitor to OPERABLE status.	30 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required containment sump monitor inoperable. AND Particulate containment atmosphere radioactivity monitor inoperable.	------------NOTE------------ LCO 3.0.4 is not applicable. -----------------------------	
	C.1.1 Analyze grab samples of the containment atmosphere.	Once per 24 hours
	OR	
	C.1.2 Perform SR 3.4.13.1	Once per 24 hours
	AND	
	C.2.1 Restore required containment sump monitor to OPERABLE status.	30 days
	OR	
	C.2.2 Restore particulate containment atmosphere radioactivity monitor to OPERABLE status.	30 days
D. Required Action and associated Completion Time of Conditions A, B, or C not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Be in MODE 5.	36 hours
E. All required monitors inoperable.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.15.1	Perform CHANNEL CHECK of the required containment atmosphere radioactivity monitor.	12 hours
SR 3.4.15.2	Perform COT of the required containment atmosphere radioactivity monitor.	92 days
SR 3.4.15.3	Perform CHANNEL CALIBRATION of the required containment sump monitor.	24 months
SR 3.4.15.4	Perform CHANNEL CALIBRATION of the required containment atmosphere radioactivity monitor.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 RCS Specific Activity

LCO 3.4.16 The specific activity of the reactor coolant shall be within limits.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS average temperature (T_{avg}) ≥ 500°F.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. DOSE EQUIVALENT I-131 specific activity not within limit.	------------NOTE------------ LCO 3.0.4 is not applicable. ----------------------------		
	A.1	Verify DOSE EQUIVALENT I-131 within the acceptable region of Figure 3.4.16-1.	Once per 8 hours
	<u>AND</u>		
	A.2	Restore DOSE EQUIVALENT I-131 to within limit.	7 days
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> DOSE EQUIVALENT I-131 specific activity in the unacceptable region of Figure 3.4.16-1.	B.1	Be in MODE 3 with T_{avg} < 500°F.	8 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Gross specific activity not within limit.	C.1 Be in MODE 3 with T_{avg} < 500°F.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	Verify reactor coolant gross specific activity ≤ 100/E μCi/gm.	7 days
SR 3.4.16.2	-------------------NOTE------------------- Only required to be performed in MODE 1. -- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity ≤ 1.0 μCi/gm.	14 days AND Between 2 and 10 hours after a THERMAL POWER change of ≥ 15% RTP within a 1 hour period

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.4.16.3 -------------------NOTE------------------- Only required to be performed in MODE 1. -- Determine $\bar{E}$ from a reactor coolant sample.	Once within 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for ≥ 48 hours. <u>AND</u> Every 184 days thereafter

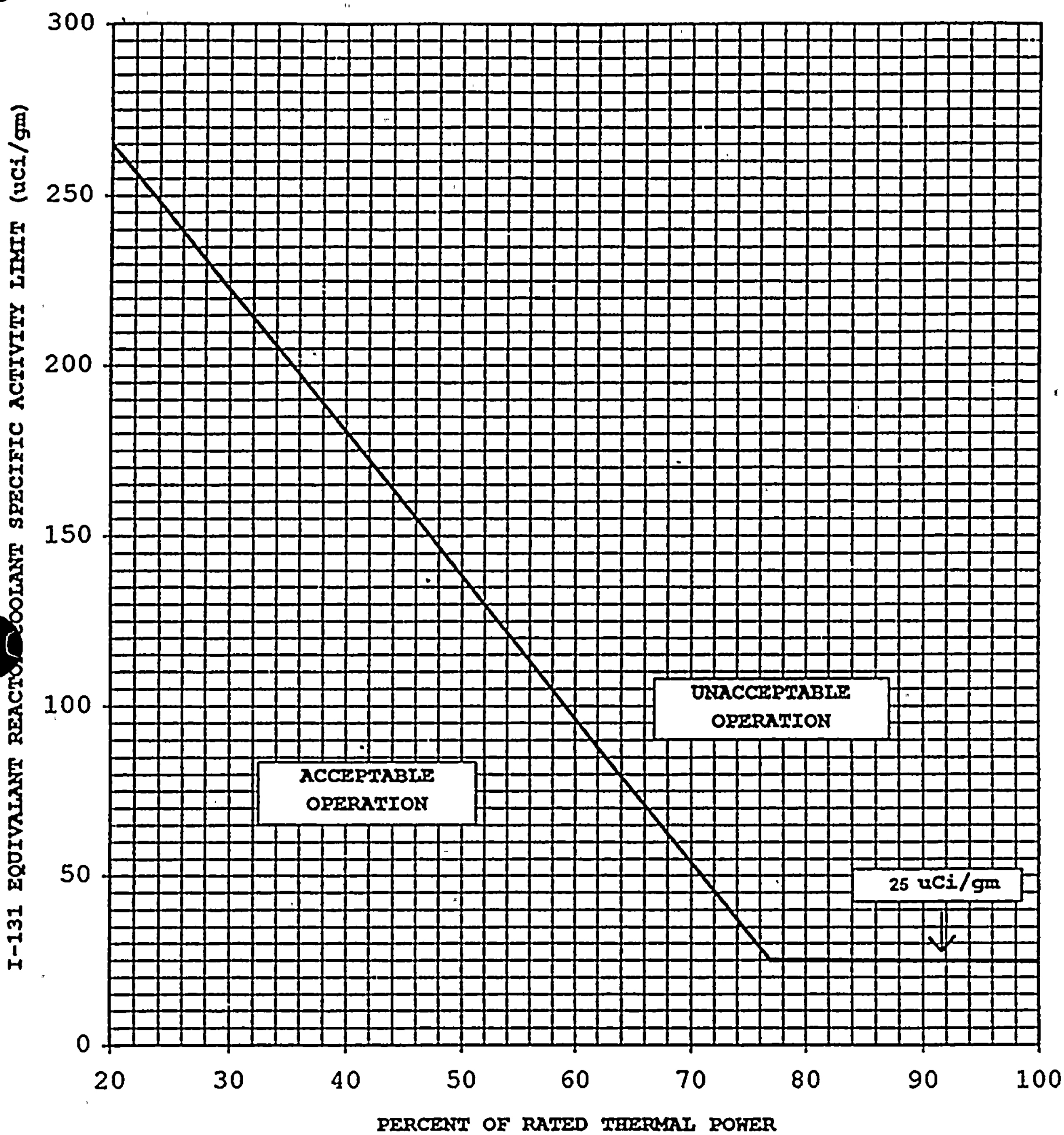


Figure 3.4.16-1
Reactor Coolant DOSE EQUIVALENT I-131 Specific Activity
Limit Versus Percent of RATED THERMAL POWER

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the limits specified in the COLR.

-------------------------NOTE---------------------------
Pressurizer pressure limit does not apply during pressure transients due to:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

APPLICABILITY: MODE 1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1 Restore RCS DNB parameter(s) to within limit.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is within limit specified in the COLR.	12 hours
SR 3.4.1.2	Verify RCS average temperature is within limit specified in the COLR.	12 hours
SR 3.4.1.3	-------------------NOTE------------------- Required to be performed within 7 days after ≥ 95% RTP. -- Verify RCS total flow rate is within the limit specified in the COLR.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 RCS Minimum Temperature for Criticality

LCO 3.4.2 Each RCS loop average temperature (T_{avg}) shall be ≥ 540°F.

APPLICABILITY: MODE 1,
MODE 2 with k_{eff} ≥ 1.0.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. T_{avg} in one or both RCS loops not within limit.	A.1 Be in MODE 2 with K_{eff} < 1.0.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	Verify RCS T_{avg} in each loop ≥ 540°F.	Within 30 minutes prior to achieving criticality.
SR 3.4.2.2	-------------------NOTE------------------- Only required if any RCS loop T_{avg} < 547°F and the low T_{avg} alarm is either inoperable or not reset. -- Verify RCS T_{avg} in each loop ≥ 540°F.	Once within 30 minutes and every 30 minutes thereafter

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.3 RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ---------NOTE--------- Required Action A.2 shall be completed whenever this Condition is entered. ---------------------- Requirements of LCO not met in MODE 1, 2, 3, or 4.	A.1 Restore parameter(s) to within limits. AND A.2 Determine RCS is acceptable for continued operation.	30 minutes 72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5 with RCS pressure < 500 psig.	6 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------NOTE--------- Required Action C.2 shall be completed whenever this Condition is entered. --------------------- Requirements of LCO not met any time in other than MODE 1, 2, 3, or 4.	C.1 Initiate action to restore parameter(s) to within limits. <u>AND</u> C.2 Determine RCS is acceptable for continued operation.	Immediately Prior to entering MODE 4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	-------------------NOTE------------------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. --- Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	30 minutes

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Loops — MODE 1 > 8.5% RTP

LCO 3.4.4 Two RCS loops shall be OPERABLE and in operation.

APPLICABILITY: MODE 1 > 8.5% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of LCO not met.	A.1 Be in MODE 1 $\leq$ 8.5% RTP.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.4.1 Verify each RCS loop is in operation.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 RCS Loops — MODES 1 ≤ 8.5% RTP, 2, and 3

LCO 3.4.5 Two RCS loops shall be OPERABLE and one loop shall be in operation.

---------------------------NOTE---------------------------
Both reactor coolant pumps may be de-energized in MODE 3 for ≤ 1 hour per 8 hour period provided:

a. No operations are permitted that would cause reduction of the RCS boron concentration; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature.

APPLICABILITY: MODES 1 ≤ 8.5% RTP,
MODES 2 and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RCS loop inoperable.	------------NOTE------------ LCO 3.0.4 is not applicable. ----------------------------	
	A.1 Verify SDM is within limits specified in the COLR.	Once per 12 hours
	AND	
	A.2 Restore inoperable RCS loop to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 4.	12 hours
C. Both RCS loops inoperable. __OR__ No RCS loop in operation.	C.1 De-energize all CRDMs. __AND__ C.2 Suspend all operations involving a reduction of RCS boron concentration. __AND__ C.3 Initiate action to restore one RCS loop to OPERABLE status and operation.	Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify required RCS loop is in operation.	12 hours
SR 3.4.5.2	Verify steam generator secondary side water levels are ≥ 16% for two RCS loops.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required RCP that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 RCS Loops — MODE 4

LCO 3.4.6 Two loops consisting of any combination of RCS loops and residual heat removal (RHR) loops shall be OPERABLE, and one loop shall be in operation.

---------------------------NOTES---------------------------

1. All reactor coolant pumps (RCPs) and RHR pumps may be de-energized for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause reduction of the RCS boron concentration; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. No RCP shall be started with any RCS cold leg temperature less than or equal to the LTOP enable temperature specified in the PTLR unless:

   a. The secondary side water temperature of each steam generator (SG) is ≤ 50°F above each of the RCS cold leg temperatures; or

   b. The pressurizer water volume is < 324 cubic feet (38% level).

APPLICABILITY: MODE 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RCS loop inoperable. AND Two RHR loops inoperable.	A.1 Initiate action to restore a second loop to OPERABLE status.	Immediately
B. One RHR loop inoperable. AND Two RCS loops inoperable.	-------------NOTE------------ Required Action B.1 is not applicable if all RCS and RHR loops are inoperable and Condition C is entered. ---------------------------- B.1 Be in MODE 5.	24 hours
C. All RCS and RHR loops inoperable. OR No RCS or RHR loop in operation.	C.1 Suspend all operations involving a reduction of RCS boron concentration. AND C.2 Initiate action to restore one loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side water level is ≥ 16% for each required RCS loop.	12 hours
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops — MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least one steam generator (SG) shall be ≥ 16%.

------------------------------NOTES------------------------------

1. The RHR pump of the loop in operation may be de-energized for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause reduction of the RCS boron concentration; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with one or more RCS cold leg temperatures less than or equal to the LTOP enable temperature specified in the PTLR unless:

   a. The secondary side water temperature of each SG is ≤ 50°F above each of the RCS cold leg temperatures; or

   b. The pressurizer water volume is < 324 cubic feet (38% level).

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

APPLICABILITY: MODE 5 with RCS loops filled.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR loop inoperable. AND Both SGs secondary side water levels not within limits.	A.1 Initiate action to restore a second RHR loop to OPERABLE status. OR A.2 Initiate action to restore required SG secondary side water levels to within limits.	Immediately Immediately
B. Both RHR loops inoperable. OR No RHR loop in operation.	B.1 Suspend all operations involving a reduction of RCS boron concentration. AND B.2 Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.7.2	Verify SG secondary side water level is ≥ 16% in the required SG.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 RCS Loops — MODE 5, Loops Not Filled

LCO 3.4.8 Two residual heat removal (RHR) loops shall be OPERABLE and one RHR loop shall be in operation.

-----------------------------NOTES-----------------------------

1. All RHR pumps may be de-energized for ≤ 15 minutes when switching from one loop to another provided:

   a. No operations are permitted that would cause a reduction of the RCS boron concentration;

   b. Core outlet temperature is maintained at least 10°F below saturation temperature; and

   c. No draining operations to further reduce the RCS water volume are permitted.

2. One RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

APPLICABILITY: MODE 5 with RCS loops not filled.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR loop inoperable.	A.1 Initiate action to restore RHR loop to OPERABLE status.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Both RHR loops inoperable. OR No RHR loop in operation.	B.1	Suspend all operations involving reduction in RCS boron concentration.	Immediately
	AND		
	B.2	Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.8.2	Verify correct breaker alignment and indicated power are available to the RHR pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Pressurizer water level not within limit.	A.1	Be in MODE 3 with reactor trip breakers open.	6 hours
	AND		
	A.2	Be in MODE 4.	12 hours
B. Pressurizer heaters capacity not within limits.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify pressurizer water level is ≤ 87%.	12 hours
SR 3.4.9.2	Verify total capacity of the pressurizer heaters is ≥ 100 Kw.	92 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Pressurizer Safety Valves

LCO 3.4.10 Two pressurizer safety valves shall be OPERABLE with lift settings ≥ 2410 psig and ≤ 2544 psig.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with all RCS cold leg temperatures greater than the LTOP enable temperature specified in the PTLR.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1 Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. OR Both pressurizer safety valves inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4 with any RCS cold leg temperature less than or equal to the LTOP enable temperature specified in the PTLR.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	--------------------NOTE------------------- Required to be performed within 36 hours of entering MODE 4 from MODE 5 with all RCS cold leg temperatures greater than the LTOP enable temperature specified in the PTLR for the purpose of setting the pressurizer safety valves under ambient (hot) conditions only provided a preliminary cold setting was made prior to heatup. --	
	Verify each pressurizer safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

LCO 3.4.11 Each PORV and associated block valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

------------------------------------NOTES------------------------------------

1. Separate entry into Condition A is allowed for each PORV.
2. Separate entry into Condition C is allowed for each block valve.
3. LCO 3.0.4 is not applicable.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or both PORVs OPERABLE and not capable of being automatically controlled.	A.1	Close and maintain power to associated block valve.	1 hour
	<u>OR</u>		
	A.2	Place associated PORV in manual control.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One PORV inoperable.	B.1	Close associated block valve.	1 hour
	<u>AND</u>		
	B.2	Remove power from associated block valve.	1 hour
	<u>AND</u>		
	B.3	Restore PORV to OPERABLE status.	72 hours
C. One block valve inoperable.	C.1	Place associated PORV in manual control.	1 hour
	<u>AND</u>		
	C.2	Restore block valve to OPERABLE status.	7 days
D. Both block valves inoperable.	D.1	Place associated PORVs in manual control.	1 hour
	<u>AND</u>		
	D.2	Restore at least one block valve to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1	Be in MODE 3.	6 hours
	AND		
	E.2	Be in MODE 4.	12 hours
F. Two PORVs inoperable.	F.1	Initiate action to restore one PORV to OPERABLE status.	Immediately
	AND		
	F.2	Close associated block valves.	1 hour
	AND		
	F.3	Remove power from associated block valves.	1 hour
	AND		
	F.4	Be in MODE 3 with T_{avg} < 500°F.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	-------------------NOTE------------------- Not required to be performed with block valve closed per LCO 3.4.13. -- Perform a complete cycle of each block valve.	92 days
SR 3.4.11.2	Perform a complete cycle of each PORV.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 Low Temperature Overpressure Protection (LTOP) System

LCO 3.4.12 An LTOP System shall be OPERABLE with the Emergency Core Cooling System (ECCS) accumulators isolated and either a or b below.

a. Two power operated relief valves (PORVs) with lift settings within the limits specified in the PTLR and no safety injection (SI) pump capable of injecting into the RCS.

b. The RCS depressurized and an RCS vent of ≥ 1.1 square inches and a maximum of one SI pump capable of injecting into the RCS.

---------------------------NOTES---------------------------

1. The PORVs and an RCS vent ≥ 1.1 square inches are not required to be OPERABLE during performance of the secondary side hydrostatic tests. However, no SI pump may be capable of injecting into the RCS during this test.

2. ECCS accumulator isolation is only required when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.

APPLICABILITY: MODE 4 when any RCS cold leg temperature is less than or equal to the LTOP enable temperature specified in the PTLR or when the RHR system is in the RHR mode of operation,
MODE 5 when the SG primary system manway and pressurizer manway are closed and secured in position,
MODE 6 when the reactor vessel head is on and the SG primary system manway and pressurizer manway are closed and secured in position.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. --------NOTE---------- Only applicable to LCO 3.4.12.a. ---------------------- One or more SI pumps capable of injecting into the RCS.	A.1	Initiate action to verify no SI pump is capable of injecting into the RCS.	Immediately
B. ----------NOTE-------- Only applicable to LCO 3.4.12.a. ---------------------- One required PORV inoperable in MODE 4.	B.1	Restore required PORV to OPERABLE status.	7 days
C. ----------NOTE-------- Only applicable to LCO 3.4.12.a. ---------------------- One required PORV inoperable in MODE 5 or MODE 6.	C.1	Restore required PORV to OPERABLE status.	72 hours
D. ----------NOTE-------- Only applicable to LCO 3.4.12.b. ---------------------- Two or more SI pumps capable of injecting into the RCS.	D.1	Initiate action to verify a maximum of one SI pump is capable of injecting into the RCS.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. An ECCS accumulator not isolated when the accumulator pressure is greater than or equal to the maximum RCS pressure for the existing cold leg temperature allowed in the PTLR.	E.1 Isolate affected ECCS accumulator.	1 hour
F. Required Action and associated Completion Time of Condition E not met.	F.1 Increase RCS cold leg temperature to greater than the LTOP enable temperature specified in the PTLR. <u>OR</u> F.2 Depressurize affected accumulator to less than the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	12 hours 12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Two required PORVs inoperable for LCO 3.4.12.a. OR Required Action and associated Completion Time of Condition A, B, C, or F not met. OR LTOP System inoperable for any reason other than Condition A, B, C, or E.	G.1 Verify at least one charging pump is in the pull-stop position. AND G.2 Depressurize RCS and establish RCS vent of ≥ 1.1 square inches.	1 hour 8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.12.1	-------------------NOTE------------------- Only required to be performed when complying with LCO 3.4.12.a. -- Verify no SI pump is capable of injecting into the RCS.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.2	------------------NOTE-------------------- Only required to be performed when complying with LCO 3.4.12.b. -- Verify a maximum of one SI pump is capable of injecting into the RCS.	12 hours
SR 3.4.12.3	------------------NOTE-------------------- Only required to be performed when ECCS accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR. -- Verify each ECCS accumulator motor operated isolation valve is closed.	Once within 12 hours and every 12 hours thereafter
SR 3.4.12.4	------------------NOTE-------------------- Only required to be performed when complying with LCO 3.4.12.b. -- Verify RCS vent ≥ 1.1 square inches open.	12 hours for unlocked open vent valve(s) <u>AND</u> 31 days for locked open vent valve(s)

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.5	Verify PORV block valve is open for each required PORV.	72 hours
SR 3.4.12.6	-------------------NOTE------------------- Required to be performed within 12 hours after decreasing RCS cold leg temperature to less than or equal to the LTOP enable temperature specified in the PTLR. -- Perform a COT on each required PORV, excluding actuation.	31 days
SR 3.4.12.7	-------------------NOTE------------------- Only required to be performed when ECCS accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR. -- Verify power is removed from each ECCS accumulator motor operated isolation valve operator.	Once within 12 hours and every 31 days thereafter
SR 3.4.12.8	Perform CHANNEL CALIBRATION for each required PORV actuation channel.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE; and

d. 0.1 gpm total primary to secondary LEAKAGE through each steam generator (SG) when averaged over 24 hours.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time not met. OR RCS pressure boundary LEAKAGE exists.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	------------------NOTE------------------ Only required to be performed during steady state operation. -- Perform RCS water inventory balance.	Once during initial 12 hours of steady state operation AND 72 hours thereafter
SR 3.4.13.2	Verify steam generator tube integrity is in accordance with the Steam Generator Tube Surveillance Program.	In accordance with the Steam Generator Tube Surveillance Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

LCO 3.4.14 Leakage from each RCS PIV shall be within limit.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-----------------------------------NOTES-----------------------------------

1. Separate Condition entry is allowed for each flow path.

2. Enter applicable Conditions and Required Actions for systems made inoperable by an inoperable PIV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more flowpaths with leakage from one or more RCS PIVs not within limit.	------------NOTE------------ Each valve used to satisfy Required Action A.1 and Required Action A.2 must have been verified to meet SR 3.4.14.1 or SR 3.4.14.2 and be in the reactor coolant pressure boundary or the high pressure portion of the system. ----------------------------	(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.1	Isolate the high pressure portion of the affected system from the low pressure portion by use of one closed manual, deactivated automatic, or check valve.	4 hours
	AND		
	A.2	Isolate the high pressure portion of the affected system from the low pressure portion by use of a second closed manual, deactivated automatic, or check valve.	72 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.14.1	-----------------------NOTES----------------------- 1. Not required to be performed until prior to entering MODE 2 from MODE 3. 2. RCS PIVs actuated during the performance of this Surveillance are not required to be tested more than once if a repetitive testing loop cannot be avoided. --	
	Verify leakage from each SI cold leg injection line and each RHR RCS PIV is equivalent to ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at an RCS pressure ≥ 2215 psig and ≤ 2255 psig.	24 months <u>AND</u> Within 24 hours following valve actuation due to automatic or manual action, flow through the valve, or maintenance on the valve

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.14.2	-------------------NOTES------------------ 1. Not required to be performed until prior to entering MODE 2 from MODE 3. 2. RCS PIVs actuated during the performance of this Surveillance are not required to be tested more than once if a repetitive testing loop cannot be avoided. ---	
	Verify leakage from each SI hot leg injection line RCS PIV is equivalent to ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at an RCS pressure ≥ 2215 psig and ≤ 2255 psig.	40 months <u>AND</u> Within 24 hours following valve actuation due to automatic or manual action, flow through the valve, or maintenance on the valve

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.15 RCS Leakage Detection Instrumentation

LCO 3.4.15 The following RCS leakage detection instrumentation shall be OPERABLE:

a. One containment sump A monitor (level or pump actuation); and

b. One containment atmosphere radioactivity monitor (gaseous or particulate).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required containment sump monitor inoperable.	------------NOTE------------ LCO 3.0.4 is not applicable. ----------------------------	
	A.1.1 Perform SR 3.4.13.1. OR	Once per 24 hours
	A.1.2 Verify containment air cooler condensate collection system is OPERABLE. AND	24 hours
	A.2 Restore required containment sump monitor to OPERABLE status.	30 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required containment atmosphere radioactivity monitor inoperable.	------------NOTE------------ LCO 3.0.4 is not applicable. ----------------------------	
	B.1.1 Analyze grab samples of the containment atmosphere.	Once per 24 hours
	<u>OR</u>	
	B.1.2 Perform SR 3.4.13.1.	Once per 24 hours
	<u>AND</u>	
	B.2 Restore required containment atmosphere radioactivity monitor to OPERABLE status.	30 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required containment sump monitor inoperable. AND Particulate containment atmosphere radioactivity monitor inoperable.	------------NOTE------------ LCO 3.0.4 is not applicable. ----------------------------	
	C.1.1 Analyze grab samples of the containment atmosphere.	Once per 24 hours
	OR	
	C.1.2 Perform SR 3.4.13.1	Once per 24 hours
	AND	
	C.2.1 Restore required containment sump monitor to OPERABLE status.	30 days
	OR	
	C.2.2 Restore particulate containment atmosphere radioactivity monitor to OPERABLE status.	30 days
D. Required Action and associated Completion Time of Conditions A, B, or C not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Be in MODE 5.	36 hours
E. All required monitors inoperable.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.15.1	Perform CHANNEL CHECK of the required containment atmosphere radioactivity monitor.	12 hours
SR 3.4.15.2	Perform COT of the required containment atmosphere radioactivity monitor.	92 days
SR 3.4.15.3	Perform CHANNEL CALIBRATION of the required containment sump monitor.	24 months
SR 3.4.15.4	Perform CHANNEL CALIBRATION of the required containment atmosphere radioactivity monitor.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 RCS Specific Activity

LCO 3.4.16 The specific activity of the reactor coolant shall be within limits.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS average temperature (T_{avg}) ≥ 500°F.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. DOSE EQUIVALENT I-131 specific activity not within limit.	------------NOTE------------ LCO 3.0.4 is not applicable. ----------------------------	
	A.1 Verify DOSE EQUIVALENT I-131 within the acceptable region of Figure 3.4.16-1.	Once per 8 hours
	AND	
	A.2 Restore DOSE EQUIVALENT I-131 to within limit.	7 days
B. Required Action and associated Completion Time of Condition A not met. OR DOSE EQUIVALENT I-131 specific activity in the unacceptable region of Figure 3.4.16-1.	B.1 Be in MODE 3 with T_{avg} < 500°F.	8 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Gross specific activity not within limit.	C.1 Be in MODE 3 with $T_{avg} < 500°F$.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	Verify reactor coolant gross specific activity ≤ 100/E μCi/gm.	7 days
SR 3.4.16.2	-------------------NOTE------------------- Only required to be performed in MODE 1. -- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity ≤ 1.0 μCi/gm.	14 days AND Between 2 and 10 hours after a THERMAL POWER change of ≥ 15% RTP within a 1 hour period

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.16.3	---NOTE--- Only required to be performed in MODE 1. --- Determine $\bar{E}$ from a reactor coolant sample.	Once within 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for $\geq$ 48 hours. AND Every 184 days thereafter

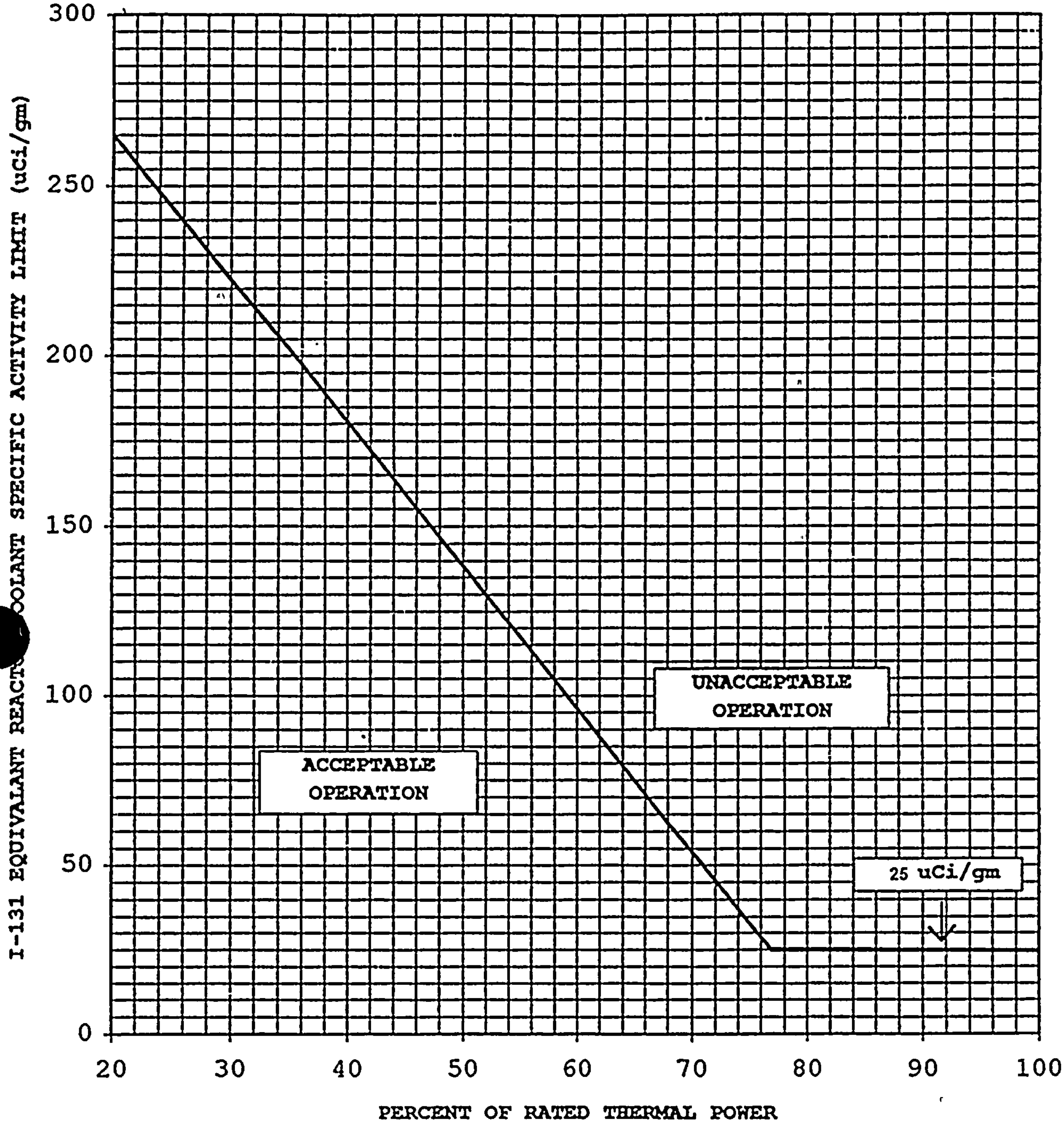


Figure 3.4.16-1
Reactor Coolant DOSE EQUIVALENT I-131 Specific Activity
Limit Versus Percent of RATED THERMAL POWER

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the departure from nucleate boiling (DNB) design criterion will be met for each of the transients analyzed.

The design method employed to meet the DNB design criterion for fuel assemblies is the Improved Thermal Design Procedure (ITDP). With the ITDP methodology, uncertainties in plant operating parameters, computer codes and DNB correlation predictions are considered statistically to obtain DNB uncertainty factors. Based on the DNB uncertainty factors, ITDP design limit departure from nucleate boiling ratio (DNBR) values are determined in order to meet the DNB design criterion.

The ITDP design limit DNBR values are 1.34 and 1.33 for the typical and thimble cells, respectively, for fuel analyses with the WRB-2 correlation.

Additional DNBR margin is maintained by performing the safety analyses to DNBR limits higher than the design limit DNBR values. This margin between the design and safety analysis limit DNBR values is used to offset known DNBR penalties (e.g., rod bow and transition core) and to provide DNBR margin for operating and design flexibility. The safety analysis DNBR values are 1.52 and 1.51 for the typical and thimble cells, respectively.

(continued)

BASES

BACKGROUND (continued)

For both the WRB-1 and WRB-2 correlations, the 95/95 DNBR correlation limit is 1.17. The W-3 DNB correlation is used where the primary DNBR correlations were developed based on mixing vane data and therefore are only applicable in the heated rod spans above the first mixing vane grid. The W-3 correlation, which does not take credit for mixing vane grids, is used to calculate DNBR values in the heated region below the first mixing vane grid. In addition, the W-3 correlation is applied in the analysis of accident conditions where the system pressure is below the range of the primary correlations. For system pressures in the range of 500 to 1000 psia, the W-3 correlation limit is 1.45. For system pressures greater than 1000 psia, the W-3 correlation limit is 1.30.

The RCS pressure limit as specified in the COLR, is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNB limits.

The RCS coolant average temperature limit as specified in the COLR, is consistent with full power operation within the nominal operational envelope. Indications of temperature are averaged to determine a value for comparison to the limit. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate as specified in the COLR, normally remains constant during an operational fuel cycle with both pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. Flow rate indications are averaged to come up with a value for comparison to the limit. A lower RCS flow will cause the core to approach DNB limits.

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNB design criterion. This is the acceptance limit for the RCS DNB parameters. Changes to the plant that could impact these parameters must be assessed for their impact on the DNB design criterion. The transients analyzed include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

The limit for pressurizer pressure is based on a ± 30 psig instrument uncertainty. The accident analyses assume that nominal pressure is maintained at 2235 psig. By Reference 2, minor fluctuations are acceptable provided that the time averaged pressure is 2235 psig.

The RCS coolant average temperature limit is based on a ± 4°F instrument uncertainty which includes a ± 1.5°F deadband. It is assumed that nominal T_{avg} is maintained within ± 1.5°F of 573.5°F. By Reference 2, minor fluctuations are acceptable provided that the time averaged temperature is within 1.5°F of nominal.

The limit for RCS flow rate is based on the nominal T_{avg} and SG plugging criteria limit. Additional margin of approximately 3% is then added for conservatism.

The RCS DNB parameters satisfy Criterion 2 of the NRC Policy Statement.

LCO

This LCO specifies limits on the monitored process variables—pressurizer pressure, RCS average temperature, and RCS total flow rate—to ensure the core operates within the limits assumed in the safety analyses. Operating within these limits will result in meeting the DNB design criterion in the event of a DNB limited transient.

(continued)

BASES

LCO (continued)

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp > 5% RTP per minute or a THERMAL POWER step > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

Another set of limits on DNB related parameters is provided in SL 2.1.1, "Reactor Core SLs." Those limits are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNB design criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In MODE 2, an increased DNBR margin exists. In all other MODES, the power level is low enough that DNB is not a concern.

ACTIONS

<u>A.1</u>

RCS pressure and RCS average temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

(continued)

BASES

ACTIONS

A.1 (continued)

The 2 hour Completion Time for restoration of the parameters provides sufficient time to determine the cause for the off normal condition, to adjust plant parameters, and to restore the readings within limits, and is based on plant operating experience.

B.1

If Required Action A.1 is not met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for pressurizer pressure is sufficient to ensure the pressure can be restored to a normal operation, steady state condition following load changes and other expected transient operations. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.1.2

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for RCS average temperature is sufficient to ensure the temperature can be restored to a normal operation, steady state condition following load changes and other expected transient operations. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.3

Measurement of RCS total flow rate once every 24 months verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate. This verification may be performed via a precision calorimetric heat balance or other accepted means.

The Frequency of 24 months reflects the importance of verifying flow after a refueling outage when the core has been altered, which may have caused an alteration of flow resistance. Verification of RCS flow rate on a shorter interval is not required since this parameter is not expected to vary during steady state operation as there are no RCS loop isolation valves or other installed devices which could significantly alter flow. Reduced performance of a reactor coolant pump (RCP) would be observable due to bus voltage and frequency changes, and installed alarms that would result in operator investigation.

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the plant in the best condition for performing the SR. The Note states that the SR shall be performed within 7 days after reaching 95% RTP. This exception is appropriate since the heat balance requires the plant to be at a minimum of 95% RTP to obtain the stated RCS flow accuracies.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Chapter 15.

2. NRC Memorandum from E.L. Jordan, Assistant Director for Technical Programs, Division of Reactor Operations Inspection to Distribution; Subject: "Discussion of Licensed Power Level (AITS F14580H2)," dated August 22, 1980.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is moderator temperature coefficient (MTC), LCO 3.1.3, "Moderator Temperature Coefficient (MTC)." In the transient and accident analyses, the MTC is assumed to be in a range from slightly positive to negative and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the RCS water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil ductility reference temperature when the reactor is critical.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for hot zero power (HZP) is a process variable that is an initial condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal, RCCA ejection, and main steam line break accidents performed at zero power that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

All low power safety analyses assume initial RCS loop temperatures greater than or equal to the HZP temperature of 547°F. The minimum temperature for criticality limitation provides a small band, 7°F, for critical operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality satisfies Criterion 2 of the NRC Policy Statement.

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) at a temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

APPLICABILITY

In MODE 1, and MODE 2 with $k_{eff} \geq 1.0$, LCO 3.4.2 is applicable since the reactor can only be critical ($k_{eff} \geq 1.0$) in these MODES.

(continued)

BASES

APPLICABILITY (continued)

The special test exception of LCO 3.1.8, "PHYSICS TESTS Exceptions - MODE 2," permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average temperatures to fall below the temperature limit of this LCO. The need to perform the PHYSICS TESTS to ensure that the operating characteristics of the core are consistent with design predictions provides sufficient justification to allow a temporary decrease in the RCS minimum temperature for criticality limit.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 2 with K_{eff} < 1.0 within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period due to the proximity to MODE 2 conditions. The allowed time is reasonable, based on operating experience, to reach MODE 2 with K_{eff} < 1.0 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

This SR verifies that RCS T_{avg} in each loop is ≥ 540°F within 30 minutes prior to achieving criticality. This ensures that the minimum temperature for criticality is being maintained just before criticality is reached.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.2.2

RCS loop average temperature is required to be verified at or above 540°F every 30 minutes in MODE 1, and in MODE 2 with $k_{eff} \geq 1.0$. The 30 minute time period is long enough to allow the operator to adjust temperatures or delay criticality so the LCO will not be violated, thereby providing assurance that the safety analyses are not violated.

This SR is modified by a Note that only requires the SR to be performed if any RCS loop T_{avg} is < 547°F and the low T_{avg} alarm is either inoperable or not reset. The T_{avg} alarm provides operator indication of low RCS temperature without requiring independent verification while a T_{avg} > 547°F in both RCS loops is within the accident analysis assumptions. If the T_{avg} alarm is to be used for this SR, it should be calibrated consistent with industry standards.

This surveillance is replaced by SR 3.1.8.2 during PHYSICS TESTING.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The PTLR contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature (Ref. 1).

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 2 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 3).

(continued)

BASES

BACKGROUND (continued)

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

The actual shift in the RT_{NDT} of the vessel material has been established by periodically removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 4) and Appendix H of 10 CFR 50 (Ref. 5). The operating P/T limit curves have been adjusted based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 6).

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

The criticality limit curve includes the Reference 2 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature for Criticality."

(continued)

BASES

BACKGROUND (continued)

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 7), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and result in nonductile failure of the RCPB which is an unanalyzed condition. Reference 1 establishes the methodology for determining the P/T limits. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing; and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

(continued)

BASES

LCO (continued)

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follow:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

(continued)

BASES

APPLICABILITY (continued)

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "RCS Minimum Temperature for Criticality"; and Safety Limit 2.1, "Safety Limits," also provide operational restrictions for pressure and temperature. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Condition A is modified by a Note stating that Required Action A.2 shall be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event which is best accomplished with the RCS at reduced pressure and temperature. In reduced pressure and temperature conditions, the possibility of propagation with undetected flaws is decreased.

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure < 500 psig within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by stress analysis.

The immediate Completion Time reflects the urgency of initiating action to restore the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished quickly in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the PTLR limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1 (continued)

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. WCAP-14040, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," Revision 1, December 1994.
2. 10 CFR 50, Appendix G.
3. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
4. ASTM E 185-82, July 1982.
5. 10 CFR 50, Appendix H.
6. Regulatory Guide 1.99, Revision 2, May 1988.
7. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops — MODE 1 > 8.5% RTP

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission;

b. Improving the neutron economy by acting as a reflector;

c. Carrying the soluble neutron poison, boric acid; and

d. Providing a second barrier against fission product release to the environment.

The reactor coolant is circulated through two loops connected in parallel to the reactor vessel, each containing a SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level and temperature instrumentation for both control and protection. The reactor vessel contains the clad fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Both transient and steady state analyses have been performed to establish the effect of flow on the departure from nucleate boiling (DNB). The transient and accident analyses for the plant have been performed assuming both RCS loops are in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the two pump coastdown, single pump locked rotor, single pump (broken shaft or coastdown), and rod withdrawal events (Ref. 1).

Steady state DNB analysis has been performed for the two RCS loop operation. For two RCS loop operation, the steady state DNB analysis, which generates the pressure and temperature Safety Limit (SL) (i.e., the departure from nucleate boiling ratio (DNBR) limit) assumes a maximum power level of 109% RTP. This is the design overpower condition for two RCS loop operation. The value for the accident analysis setpoint of the nuclear overpower (high flux) trip is 118% and is based on an analysis assumption that bounds all possible instrumentation errors (Ref. 2). The DNBR limit defines a locus of pressure and temperature points that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

The plant is designed to operate with both RCS loops in operation to maintain DNBR above the SL, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant. Adequate heat transfer between the reactor coolant and the secondary side is ensured by maintaining ≥ 16% SG level in accordance with LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation," which provides sufficient water inventory to cover the SG tubes.

RCS Loops — MODE 1 > 8.5% RTP satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, two pumps are required to be in operation at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program.

APPLICABILITY

In MODE 1 > 8.5% RTP, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, both RCS loops are required to be OPERABLE and in operation in this MODE to prevent DNB and core damage.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower MODES as indicated by the LCOs for MODES 1 ≤ 8.5% RTP, 2, 3, 4, and 5.

Operation in other MODES is covered by:
LCO 3.4.5, "RCS Loops - MODES 1 ≤ 8.5% RTP, 2, AND 3";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - Water Level ≥ 23 Ft" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Water Level < 23 Ft" (MODE 6).

ACTIONS

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 1 < 8.5% RTP. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

(continued)

BASES

ACTIONS

A.1 (continued)

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 1 < 8.5% RTP from full power conditions in an orderly manner and without challenging safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification every 12 hours that each RCS loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. Use of control board indication for these parameters is an acceptable verification. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

REFERENCES

1. UFSAR, Chapter 15.

2. UFSAR, Section 15.0.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loops — MODES 1 ≤ 8.5% RTP, 2, AND 3

BASES

BACKGROUND

In MODE 1 ≤ 8.5% RTP, and in MODE 2 and 3, the primary function of the RCS is the removal of decay heat and transfer of this heat, via the steam generator (SG), to the secondary plant. The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission (MODE 1 ≤ 8.5% RTP and MODE 2 only);

b. Improving the neutron economy by acting as a reflector (MODE 1 ≤ 8.5% RTP and MODE 2 only);

c. Carrying the soluble neutron poison, boric acid; and

d. Providing a second barrier against fission product release to the environment.

The reactor coolant is circulated through two RCS loops, connected in parallel to the reactor vessel, each containing a SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The reactor vessel contains the clad fuel. The SGs provide the heat sink. The RCPs circulate the water through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage.

In MODE 1 ≤ 8.5% RTP and MODE 2, the RCPs are used to provide forced circulation of the reactor coolant to ensure mixing of the coolant for proper boration and chemistry control and to remove the limited amount of reactor heat. In MODE 3, the RCPs are used to provide forced circulation for heat removal during heatup and cooldown. The MODE 1 ≤ 8.5% RTP, 2, and 3 reactor and decay heat removal requirements are low enough that a single RCS loop with one RCP running is sufficient to remove core decay heat. However, two RCS loops are required to be OPERABLE to ensure redundant capability for decay heat removal.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Both transient and steady state analyses have been performed to establish the effect of flow on the departure from nucleate boiling (DNB). In MODE 1 ≤ 8.5% RTP, and in MODES 2 and 3, these analyses include evaluation of main steam line breaks and uncontrolled rod withdrawal from a subcritical condition. The most limiting accident with respect to DNB limits for MODES 1 ≤ 8.5% RTP, 2, and 3 is a main steam line break. This is due to the potential for recriticality and because of the high hot channel factors that may exist if the most reactive control rod is stuck in its fully withdrawn position.

A main steam line break has been analyzed for both the case with one and two RCS loops in operation at hot zero power (HZP) conditions with acceptable results (Ref. 1). However, with only one RCS loop in operation and offsite power available, additional shutdown margin is required since the reduced flow produces an adverse effect on DNB limits.

The startup of an inactive reactor coolant pump (RCP) up to 8.5% RTP has been evaluated and found to result in only limited power and temperature excursions that are bounded by a main steam line break with only one RCS Loop in operation (Refs. 2 and 3).

Analyses have also been performed which demonstrate that reactor heat greater than 5% RTP can be removed by natural circulation alone (Ref. 4).

Failure to provide decay heat removal may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier. RCS Loops — MODES 1 ≤ 8.5 % RTP, 2, and 3 satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

The purpose of this LCO is to require that both RCS loops be OPERABLE. Only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS up to 8.5% RTP. An additional RCS loop is required to be OPERABLE to ensure that safety analyses limits are met. Requiring one RCS loop in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents.

The Note permits all RCPs to be de-energized for ≤ 1 hour per 8 hour period in MODE 3. The purpose of the Note is to perform tests that are designed to validate various accident analyses values. One of these tests is validation of the pump coastdown curve used as input to a number of accident analyses including a loss of flow accident. This test was satisfactorily performed during the initial startup testing program (Ref. 5). If, however, changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values of the coastdown curve must be revalidated by conducting the test again.

The no flow test may be performed in MODE 3, 4, or 5. The Note permits the de-energizing of the pumps in order to perform this test and validate the assumed analysis values. As with the validation of the pump coastdown curve, this test should be performed only once unless the flow characteristics of the RCS are changed. The 1 hour time period specified is adequate to perform the desired tests, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, thereby maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

(continued)

BASES

LCO (continued)

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

An OPERABLE RCS loop consists of an OPERABLE RCP and an OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program, which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and able to provide forced flow if required.

APPLICABILITY

In MODES 1 ≤ 8.5% RTP, 2, and 3, this LCO ensures forced circulation of the reactor coolant to remove reactor and decay heat from the core and to provide proper boron mixing.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODE 1 > 8.5% RTP";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — Water Level ≥ 23 Ft" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Water Level < 23 Ft" (MODE 6).

ACTIONS

A.1 and A.2

If one RCS loop is inoperable, redundancy for heat removal is lost. The Required Actions are to verify that the SDM is within limits specified in the COLR. This action is required to ensure that adequate SDM exists in the event of a main steam line break with only one RCS loop in operation. The 12 hour Frequency considers the time required to obtain RCS boron concentration samples and the low probability of a main steam line break during this time period.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

The inoperable RCS loop must be restored to OPERABLE status within the Completion Time of 72 hours. This time allowance is a justified period to be without the redundant, nonoperating loop because a single loop in operation has a heat transfer capability greater than that needed to remove the reactor and decay heat produced in the reactor core and because of the low probability of a failure in the remaining loop occurring during this period.

Required Action A.1 is modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one RCS loop is inoperable. This allowance is provided because a single RCS loop can provide the required cooling to remove reactor and decay heat consistent with safety analysis assumptions.

B.1

If restoration of the inoperable loop is not possible within 72 hours, the plant must be brought to MODE 4. In MODE 4, the plant may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

C.1, C.2, and C.3

If two RCS loops are inoperable, or no RCS loop is in operation, except during conditions permitted by the Note in the LCO section, all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets. All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that each required RCS loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. Use of the control board indication for these parameters is an acceptable verification. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

This SR requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 16% for two RCS loops. If the SG secondary side narrow range water level is < 16%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of reactor or decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.5.3

Verification that the required RCP is OPERABLE ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump that is not in operation. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. UFSAR Section 15.1.5.

2. UFSAR Section 15.4.3.

3. Letter from D. M. Crutchfield, NRC, to J. E. Maier, RG&E, Subject: "SEP Topic XV-9, Startup of an Inactive Loop, R. E. Ginna," dated August 26, 1981.

4. UFSAR Sections 14.6.1.5.6 and 15.2.5.2.

5. UFSAR Section 14.6.1.5.5.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops—MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through two RCS loops connected in parallel to the reactor vessel, each containing a SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The reactor vessel contains the cladded fuel. The SGs or the RHR heat exchangers provide the heat sink. The RCPs and the RHR pumps circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and to prevent boric acid stratification.

In MODE 4, either RCS or RHR loops can be used to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCS or one RHR loop for decay heat removal and transport. The flow provided by one RCS loop or one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for decay heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation is considered in the determination of the time available for mitigation of an accidental boron dilution event. The RCS and RHR loops provide this circulation.

RCS Loops—MODE 4 have been identified in the NRC Policy Statement as important contributors to risk reduction.

(continued)

BASES

LCO (continued)

Note 2 requires that the pressurizer water volume be < 324 cubic feet (38% level), or that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature less than or equal to the LTOP enable temperature specified in the PTLR. The water volume limit ensures that the pressurizer will accommodate the swell resulting from an RCP start. Restraints on the pressurizer water volume and SG secondary side water temperature prevent a low temperature overpressure event due to a thermal transient when an RCP is started and the colder RCS water enters the warmer SG and expands. Violation of this Note places the plant in an unanalyzed condition.

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program, which has the minimum water level specified in SR 3.4.6.2. RCPs are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. An OPERABLE RHR loop may be isolated from the RCS provided that the loop can be placed into service from the control room. RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of either RCS or RHR provides sufficient circulation for these purposes. However, two loops consisting of any combination of RCS and RHR loops are required to be OPERABLE to meet single failure considerations.

(continued)

BASES

APPLICABILITY (continued)

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODE 1 > 8.5% RTP ";
LCO 3.4.5, "RCS Loops — MODES 1 ≤ 8.5% RTP, 2, AND 3";
LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — Water Level ≥ 23 Ft" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Water Level < 23 Ft" (MODE 6).

ACTIONS

A.1

If one RCS loop is inoperable and two RHR loops are inoperable, redundancy for heat removal is lost. Action must be initiated to restore a second RCS or RHR loop to OPERABLE status. If no RHR is available, the plant cannot enter a reduced MODE since no long term means of decay heat removal would be available. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1

If one RHR loop is inoperable and both RCS loops are inoperable, an inoperable RCS or RHR loop must be restored to OPERABLE status to provide a redundant means for decay heat removal.

If the parameters that are outside the limits cannot be restored, the plant must be brought to MODE 5 within 24 hours. Bringing the plant to MODE 5 is a conservative action with regard to decay heat removal. With only one RHR loop OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the remaining RHR loop, it would be safer to initiate that loss from MODE 5 (≤ 200°F) rather than MODE 4 (200 to 350°F). The Completion Time of 24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS

B.1 (continued)

Required Action B.1 is modified by a Note stating that only the Required Actions of Condition C are entered if all RCS and RHR loops are inoperable. With all RCS and RHR loops inoperable, MODE 5 cannot be entered and Required Actions C.1 and C.2 are the appropriate remedial actions.

C.1 and C.2

If no loop is OPERABLE or in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RCS or RHR loop to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that one RCS or RHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. Use of control board indication for these parameters is an acceptable verification. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS and RHR loop performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

This SR requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 16%. If the SG secondary side narrow range water level is < 16%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump that is not in operation. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. UFSAR, Section 14.6.1.2.6.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops—MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat either to the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is normally circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining one SG with a secondary side water level at or above 16% to provide an alternate method for decay heat removal.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of an accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops — MODE 5 (Loops Filled) have been identified in the NRC Policy Statement as important contributors to risk reduction.

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or one SG with a secondary side water level ≥ 16%. One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is one SG with a secondary side water level ≥ 16%. Should the operating RHR loop fail, the SG could be used to remove the decay heat.

Note 1 permits all RHR pumps to be de-energized ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. One of the tests performed during the startup testing program was the validation of rod drop times during cold conditions, both with and without flow (Ref. 1). If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits de-energizing of the pumps in order to perform this test and validate the assumed analysis values. The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by test procedures:

(continued)

BASES

LCO (continued)

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period ≤ 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

Note 3 requires that the pressurizer water volume be < 324 cubic feet (38% level), or that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of a reactor coolant pump (RCP) with an RCS cold leg temperature less than or equal to the LTOP enable temperature specified in the PTLR. The water volume limit ensures that the pressurizer will accommodate the swell resulting from an RCP start. Restraints on the pressurizer water volume and SG secondary side water temperature are to prevent a low temperature overpressure event due to a thermal transient when an RCP is started and the colder RCS water enters the warmer SG and expands. Violation of this Note places the plant in an unanalyzed Condition.

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops. A planned heatup is a scheduled transition to MODE 4 within a defined time period.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. A SG can perform as a heat sink when it is OPERABLE in accordance with the Steam Generator Tube Surveillance Program, with the minimum water level specified in SR 3.4.7.2.

(continued)

BASES (continued)

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The RCS loops are considered filled until the isolation valves are opened to facilitate draining of the RCS. The loops are also considered filled following the completion of filling and venting the RCS. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least one SG is required to be ≥ 16%.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODE 1 > 8.5% RTP";
LCO 3.4.5, "RCS Loops — MODES 1 ≤ 8.5% RTP, 2, AND 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — Water Level ≥ 23 Ft" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Water Level < 23 Ft" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and both SGs have secondary side water levels < 16%, redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore at least one SG secondary side water level. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal. The action to restore must continue until an RHR loop is restored to OPERABLE status or SG secondary side water level is restored.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Notes 1 and 4, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that one RHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. Use of control board indication for these parameters is an acceptable verification. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

This SR requires verification of SG OPERABILITY. Verifying that at least one SG is OPERABLE by ensuring its secondary side narrow range water level is ≥ 16% ensures an alternate decay heat removal method in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the standby RHR pump. If secondary side water level is ≥ 16% in at least one SG, this Surveillance is not needed. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. UFSAR, Section 14.6.1.2.6

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops — MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to the component cooling water via the residual heat removal (RHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with loops not filled, only RHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR pump for decay heat removal and transport and to require that two paths be available to provide redundancy for heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of an accidental boron dilution event. The RHR loops provide this circulation. The flow provided by one RHR loop is adequate for heat removal and for boron mixing.

RCS loops in MODE 5 (loops not filled) have been identified in the NRC Policy Statement as important contributors to risk reduction.

LCO

The purpose of this LCO is to require that at least two RHR loops be OPERABLE and one of these loops be in operation to transfer heat from the reactor coolant at a controlled rate. Heat cannot be removed via the RHR System unless forced flow is used. A minimum of one operating RHR pump meets the LCO requirement for one loop in operation. An additional RHR loop is required to be OPERABLE to meet single failure considerations.

(continued)

BASES

LCO (continued)

Note 1 permits all RHR pumps to be de-energized for ≤ 15 minutes when switching from one loop to another. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and requires that the following conditions be met:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation;

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction; and

c. No draining operations are permitted that would further reduce the RCS water volume and possibly cause a more rapid heatup of the remaining RCS inventory.

Note 2 allows one RHR loop to be inoperable for a period of ≤ 2 hours, provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when these tests are safe and possible.

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.

APPLICABILITY

In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System. The RCS loops are considered not filled from the time period beginning with the opening of isolation valves and draining of the RCS and ending with the completion of filling and venting the RCS.

(continued)

BASES

APPLICABILITY (continued)

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODE 1 > 8.5% RTP";
LCO 3.4.5, "RCS Loops — MODES 1 ≤ 8.5% RTP, 2, AND 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — Water Level ≥ 23 Ft" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Water Level < 23 Ft" (MODE 6).

ACTIONS

A.1

If only one RHR loop is OPERABLE and in operation, redundancy for RHR is lost. Action must be initiated to restore a second loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal. The action to restore must continue until the second RHR loop is restored to OPERABLE status.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification every 12 hours that one RHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.8.2

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the standby pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation, and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level and the required heater capacity. Pressurizer safety valves and pressurizer power operated relief valves are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Pressurizer Power Operated Relief Valves (PORVs)," respectively.

The intent of this LCO is to ensure that a steam bubble exists in the pressurizer prior to, and during, power operation to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions. Relatively small amounts of noncondensible gases are typically present in the RCS and can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control. These noncondensible gases can be ignored if the steam bubble is present.

(continued)

BASES

BACKGROUND (continued)

This LCO also ensures that adequate heater capacity is available in the pressurizer to support natural circulation following an extended loss of offsite power. Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. These heaters are divided into two groups, a control/variable group and a backup group. The control/variable group is normally used during power operation since these heaters have inverse proportional control with respect to the pressurizer pressure. The backup group is either fully on or off with setpoints that are below those for the control/variable group. Both groups of heaters receive power from the Engineered Safety Feature (ESF) 480 V buses, however, the heaters are shed following a loss of offsite power or safety injection signal. The heaters can be manually loaded onto the diesel generators if required.

A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained during natural circulation. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat. Unless adequate heater capacity is available, the required subcooling margin in the primary system cannot be maintained. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of single phase natural circulation and decreased capability to remove core decay heat. Maintaining necessary subcooled margin during normal power operation is controlled by meeting the requirements for pressurizer level and LCO 3.4.1, "RCS Pressure, Temperature and Flow Departure From Nucleate Boiling (DNB) Limits."

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting with respect to pressurizer parameters. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present. The maximum pressurizer water level limit ensures that a steam bubble exists and satisfies Criterion 2 of the NRC Policy Statement. Safety analyses presented in the UFSAR (Ref. 1) do not take credit for pressurizer heater operation, however, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO. The pressurizer heaters are assumed to be available within one hour following the loss of offsite power and initiation of natural circulation (Ref. 3).
LCO	The LCO establishes the minimum conditions required to ensure that a steam bubble exists within the pressurizer and that sufficient heater capacity is available to support an extended loss of offsite power event. For the pressurizer to be considered OPERABLE, the limits established in the SRs for water level and heater capacity must be met and the heaters must be capable of being powered from an emergency power source within one hour.
APPLICABILITY	The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3 to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

(continued)

BASES

APPLICABILITY (continued)

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from an emergency power supply (Ref. 4). In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

ACTIONS

A.1 and A.2

If the pressurizer water level is > 650 cubic feet, which is equivalent to 87%, the ability to maintain a steam bubble may no longer exist. The steam bubble is necessary to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions. Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions. Normally the plant will trip in this event since the upper limit is the same as the Pressurizer High Level Trip.

If the pressurizer water level is not within the limit, action must be taken to restore the plant to operation within the bounds of the safety analyses. To achieve this status, the plant must be brought to MODE 3, with the reactor trip breakers open, within 6 hours and to MODE 4 within 12 hours. This takes the plant out of the applicable MODES and restores the plant to operation within the bounds of the safety analyses. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the pressurizer heaters capacity is < 100 KW, the ability to maintain RCS pressure to support natural circulation may no longer exist. By maintaining RCS pressure control, a margin to subcooling is provided. The value of 100 KW is based on the amount needed to support natural circulation after accounting for heat losses through the pressurizer insulation during an extended loss of offsite power event.

If the capacity of the pressurizer heaters is not within the limit, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Frequency of 12 hours has been shown by operating practice to be sufficient to regularly assess level for any deviation and verify that operation is within safety analyses assumptions. Alarms are also available for early detection of abnormal level indications.

SR 3.4.9.2

This SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power required. This may be done by testing the power supply output by verifying the electrical load on Buses 14 and 16 with the respective heater groups on and off. The Frequency of 92 days is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Chapter 15.

2. NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

3. Letter from B. L. King, Westinghouse Electric Corporation, to R. C. Mecredy, RG&E, Subject: "Ability to Maintain Subcooled Conditions During an Extended Loss of Offsite Power," dated September 26, 1979.

4. Letter from D. M. Crutchfield, NRC, to L. D. White, Jr. RG&E, Subject: "Lessons Learned Category 'A' Evaluation," dated July 7, 1980.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed pop type, spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The relief capacity for each valve, 288,000 lbm/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves or increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5 and in MODE 6 with reactor vessel head on; however, in MODE 4, with either RCS cold leg temperature less than or equal to the LTOP enable temperature specified in the PTLR, and MODE 5 and MODE 6 with the reactor vessel head on and the SG primary system manway and pressurizer manway closed and secured in position, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

The upper and lower pressure limits are based on the ± 1% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

(continued)

BASES

BACKGROUND (continued)

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure for all anticipated transients except for the locked rotor accident which remains below 120% of the design pressure consistent with the original maximum transient pressure limit for the RCS (Refs. 2, 3 and 4). The consequences of exceeding the American Society of Mechanical Engineers (ASME) and USAS Section B31.1 pressure limits (Refs. 1 and 4) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

APPLICABLE SAFETY ANALYSES

All accident and safety analyses in the UFSAR (Ref. 5) that require safety valve actuation assume operation of both pressurizer safety valves to limit increases in RCS pressure. The overpressure protection analysis (Ref. 6) is also based on operation of both safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal from full power;

b. Loss of reactor coolant flow;

c. Loss of external electrical load (including the complete loss of steam flow to the turbine);

d. Loss of normal feedwater;

e. Loss of all AC power to station auxiliaries; and

f. Locked rotor.

Detailed analyses of the above transients are contained in Reference 5. Safety valve actuation is required in events c, d, e, and f (above) to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions.

Pressurizer safety valves satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

The two pressurizer safety valves are set to open at the RCS design pressure (2500 psia), and within the ASME specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits following testing are based on the ± 1% tolerance requirements (Ref. 1) for lifting pressures above 1000 psig. The OPERABILITY limits of + 2.4%, - 3% are based on the analyzed events. The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure for all transients except locked rotor accidents which has an allowed limit of 120% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the LTOP arming temperature, OPERABILITY of two valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 and portions of MODE 4 are conservatively included, although the listed accidents may not require the safety valves for protection.

The LCO is not applicable in MODE 4 when either RCS cold leg temperature is less than or equal to the LTOP enable temperature specified in the PTLR or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with the reactor vessel head detensioned or the SG primary system manway or the pressurizer manway open.

(continued)

BASES (continued)

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS Overpressure Protection System. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if both pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with either RCS cold leg temperature less than or equal to the LTOP enable temperature specified in the PTLR within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. With any RCS cold leg temperature at or below the LTOP enable temperature specified in the PTLR, overpressure protection is provided by the LTOP System. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by both pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of Section XI of the ASME Code (Ref. 7), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is + 2.4%, - 3% for OPERABILITY; however, the valves are reset to ± 1% during the surveillance to allow for drift.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1 (continued)

This SR is modified by a Note that allows entry into MODES 3 and 4 without having performed the SR for the purpose of setting the pressurizer safety valves under ambient (hot) conditions. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition until completion of the surveillance.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.

2. UFSAR, Section 15.3.2.

3. Letter from D. M. Crutchfield, NRC, to J. E. Maier, RG&E, Subject: "SEP Topic XV-1, XV-2, XV-3, XV-4, XV-5, XV-6, XV-7, XV-8, XV-10, XV-12, XV-14, XV-15, and XV-17, Design Basis Events, Accidents, and Transients (R.E. Ginna)," dated September 4, 1981.

4. USAS B31.1, Standard Code for Pressure Piping, American Society of Mechanical Engineers, 1967 edition.

5. UFSAR, Chapter 15.

6. WCAP-7769, "Topical Report, Overpressure Protection for Westinghouse Pressurized Water Reactors," Rev. 1, June 1972.

7. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and PORVs. The PORVs (430 and 431C) are air operated valves that are controlled to open at a specific set pressure when the pressurizer pressure increases and close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

Motor operated block valves (515 and 516), which are normally open, are located between the pressurizer and the PORVs. The block valves are used to isolate the PORVs in case of excessive leakage or a stuck open PORV. Block valve closure is accomplished manually using controls in the control room. A stuck open PORV is, in effect, a small break loss of coolant accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permit performance of surveillances on the valves during power operation.

The PORVs may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater and auxiliary feedwater. The PORVs are also used to mitigate the effects of an anticipated transient without scram (ATWS) event which is also not within the design basis.

The PORVs, their block valves, and their controls are powered from the vital buses that normally receive power from offsite power sources, but are also capable of being powered from emergency power sources in the event of a loss of offsite power. The two PORVs (in manual operation only) and their associated block valves are powered from two separate safety trains.

(continued)

BASES

BACKGROUND (continued)

The plant has two PORVs, each having a relief capacity of 179,000 lb/hr at 2335 psig. The PORVs are normally opened by using instrument air which is supplied through separate solenoid operated valves (8620A and 8620B). The safety related source of motive air is from two separate nitrogen accumulators that are normally isolated from the PORVs by solenoid operated valves 8619A and 8619B; however, solenoid operated valves 8620A and 8620B must be in the vent position to close the PORVs regardless of which motive air source is used.

The functional design of the PORVs is based on maintaining pressure below the pressurizer high pressure reactor trip setpoint following a step reduction of 50% of full load with steam dump. In addition, the PORVs minimize challenges to the pressurizer safety valves and also may be used for low temperature overpressure protection (LTOP). See LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

APPLICABLE SAFETY ANALYSES

Plant operators employ the PORVs to depressurize the RCS in response to certain plant transients if normal pressurizer spray is not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the affected steam generator.

The PORVs are also used in safety analyses for events that result in increasing RCS pressure for which departure from nucleate boiling ratio (DNBR) criteria are critical. By assuming PORV manual actuation, the primary pressure remains below the pressurizer high pressure trip and pressurizer safety valve setpoints; thus the DNBR calculation is more conservative assuming the same initial RCS temperature since the pressurizer pressure is limited. Events that assume this condition include a loss of external electrical load and other transients which result in a decrease in heat removal by the secondary system (Ref. 1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Pressurizer PORVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

The LCO requires the PORVs and their associated block valves to be OPERABLE for manual operation by the nitrogen accumulators to mitigate the effects associated with an SGTR.

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. The block valves are available to isolate the flow path through either a failed open PORV or a PORV with excessive leakage. Satisfying the LCO helps minimize challenges to fission product barriers.

APPLICABILITY

In MODES 1, 2, and 3, the PORV is required to be OPERABLE to mitigate the effects associated with an SGTR and its block valve must be OPERABLE to limit the potential for a small break LOCA through the flow path. The most likely cause for a PORV small break LOCA is a result of a pressure increase transient that causes the PORV to automatically open with a subsequent failure to close. Imbalances in the energy output of the core and heat removal by the secondary system can cause the RCS pressure to increase to the PORV opening setpoint. The most rapid increases will occur at the higher operating power and pressure conditions of MODES 1 and 2. Pressure increases are less prominent in MODE 3 because the core input energy is reduced, but the RCS pressure is high.

The PORVs are also required to be OPERABLE in MODES 1, 2, and 3 to minimize challenges to the pressurizer safety valves. Therefore, the LCO is applicable in MODES 1, 2, and 3.

The LCO is not applicable in MODE 4 when both pressure and core energy are decreased and the pressure surges become much less significant. The PORV setpoint is reduced for LTOP in MODES 4, 5, and 6 with the reactor vessel head in place. LCO 3.4.12 addresses the PORV requirements in these MODES.

(continued)

BASES (continued)

ACTIONS

Note 1 has been added to clarify that both pressurizer PORVs are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis) for Condition A. Note 2 has been added to clarify that both block valves are treated as separate entities, each with separate Completion Times, for Condition C. The exception for LCO 3.0.4, Note 3, permits entry into MODES 1, 2, and 3 to perform cycling of the PORVs or block valves to verify their OPERABLE status. Testing is not performed in lower MODES due to LTOP considerations.

A.1 and A.2

With the PORVs OPERABLE and not capable of being automatically controlled, either the PORVs must be restored or the flow path isolated within 1 hour. Although a PORV may not be capable of being automatically controlled, it may be able to be manually opened and closed, and therefore, able to perform its function. A PORV is considered not capable of being automatically controlled for any problem which prevents the PORV from automatically closing once it has automatically opened. This may be due to instrumentation problems. Not capable of automatic control does not include problems which only prevent the PORV from automatically opening (e.g., loss of instrument air to the PORV). It also does not include problems which prevent the PORV from both automatically opening and automatically closing. For these reasons, the block valve may either be closed to isolate the flowpaths or isolated by placing the PORV control switch in the closed position. However, if the block valve is closed to isolate the flowpath, the Action requires power be maintained to the valve. This Condition is only intended to permit operation of the plant for a limited period of time not to exceed the next refueling outage (MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem. Normally, the PORVs should be available for automatic mitigation of overpressure events and should be returned to OPERABLE status prior to entering startup (MODE 2). Seat leakage problems are controlled by LCO 3.4.13, "RCS Operational LEAKAGE."

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

B.1, B.2, and B.3

If one PORV is not capable of being manually cycled, it is inoperable and must be either restored or isolated by closing the associated block valve and removing the power to the associated block valve. PORV inoperability includes (but is not limited to) the inability of the solenoid operated isolation valve from the nitrogen accumulator to open or the solenoid operated isolation valve from instrument air to vent. The Completion Times of 1 hour are reasonable, based on challenges to the PORVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time. Because there is a second PORV that is OPERABLE, an additional 72 hours is provided to restore the inoperable PORV to OPERABLE status. If the PORV cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition E.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the Completion Time of 1 hour or place the associated PORV in manual control. The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. Manual control is accomplished by placing the PORV control board switch in the closed position. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation. Because the PORV is not capable of automatically opening and the small potential for an SGTR or other event requiring Manual operation, the operator is permitted a Completion Time of 7 days to restore the inoperable block valve to OPERABLE status. The time allowed to restore the block valve is limited to 7 days since the PORVs are not capable of automatically mitigating an overpressure event when placed in manual control. If the block valve is restored within the Completion Time of 7 days, the PORV will again be capable of automatically responding to an overpressure event, and the block valves capable of isolating a stuck open PORV which may result from the overpressure event. If it cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition E.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If both block valves are inoperable, then it is necessary to either restore at least one block valve to OPERABLE status within the Completion Time of 1 hour or place the PORVs in manual control. The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valves cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORVs in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. Manual control is accomplished by placing the PORV control board switch in the closed position. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation. Because the PORV is not capable of automatically opening and the small potential for an SGTR or other event requiring Manual operation, the operator is permitted a Completion Time of 72 hours to restore at least one inoperable block valve to OPERABLE status. The time allowed to restore one block valve is limited to 72 hours since the PORVs are not capable of automatically mitigating an overpressure event when placed in manual control. If at least one block valve is restored within the Completion Time of 72 hours, at least one PORV will again be capable of automatically responding to an overpressure event, and the associated block valve capable of isolating a stuck open PORV which may result from the overpressure event. If it cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition E.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

If the Required Action of Condition A, B, C, or D is not met, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, maintaining PORV OPERABILITY may be required. See LCO 3.4.12.

F.1, F.2, F.3, and F.4

If both PORVs are not capable of being manually cycled, they are inoperable and it is necessary to initiate action to restore one PORV to OPERABLE status immediately since no relief valve is available to mitigate the effects associated with an SGTR. Therefore, operators must either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation.

(continued)

BASES

ACTIONS

F.1, F.2, F.3, and F.4 (continued)

If one PORV is restored and one PORV remains inoperable, then the plant will be in Condition B with the time clock started at the original declaration of having two PORVs inoperable. If no PORVs are restored within the Completion Time, then the plant must be brought to a MODE which does not require manual PORV operation. To achieve this status, the plant must be brought to MODE 3 with T_{avg} < 500°F within 8 hours. In MODE 3 with the RCS average temperature < 500°F, the saturation pressure of the reactor coolant is below the setpoint of the main steam safety valves. Since the RWST contains a larger volume of water than the secondary side of an SG, the leak through the ruptured tube will stop after the SG is filled to capacity. Therefore, an SGTR can be mitigated under these conditions without any release of radioactive fluid through the main steam safety valves. Entering a lower MODE is not desirable with both PORVs inoperable and not capable of being manually cycled since the PORVs are also required for low temperature overpressure protection. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be closed if needed. The basis for the Frequency of 92 days is the ASME Code, Section XI (Ref. 2). If the block valve is closed to isolate a PORV that is OPERABLE and is not leaking in excess of the limits of LCO 3.4.13, "RCS Operational LEAKAGE," then opening the block valve is necessary to verify that the PORV can be used for manual control of reactor pressure. If the block valve is closed to isolate an otherwise inoperable PORV, the maximum Completion Time to restore the PORV and open the block valve is 72 hours, which is well within the allowable limits (25%) to extend the block valve Frequency of 92 days. Furthermore, these test requirements would be completed by the reopening of a recently closed block valve upon restoration of the PORV to OPERABLE status (i.e., completion of the Required Actions fulfills the SR).

The Note modifies this SR by stating that it is not required to be performed with the block valve closed per LCO 3.4.13. This prevents the need to open the block valve when the associated PORV is leaking > 10 gpm creating the potential for a plant transient.

SR 3.4.11.2

This SR requires a complete cycle of each PORV using the nitrogen accumulators. Operating a PORV through one complete cycle ensures that the PORV can be manually actuated for mitigation of an SGTR. The Frequency of 24 months is based on a typical refueling cycle and industry accepted practice.

REFERENCES

1. UFSAR, Section 15.2.

2. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System controls RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The LTOP system also protects the RHR system from overpressurization during the RHR mode of operation. The PTLR provides the maximum allowable actuation logic setpoints for the pressurizer power operated relief valves (PORVs) and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperatures. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

(continued)

BASES

BACKGROUND (continued)

This LCO provides RCS overpressure protection by restricting coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires isolating the Emergency Core Cooling System (ECCS) accumulators and rendering all safety injection (SI) pumps incapable of RCS injection when the PORVs provide the RCS vent path and rendering a minimum of two SI pumps incapable of RCS injection when the RCS is depressurized with an RCS vent ≥ 1.1 square inches. The pressure relief capacity requires either two redundant PORVs or a depressurized RCS and an RCS vent of sufficient size. One PORV or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

By restricting coolant input capability, the ability to provide core coolant addition is minimized. The LCO does not require the makeup control system to be deactivated or the SI actuation circuits blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the makeup system can provide adequate flow via the makeup control valve. If the conditions require the use of SI for makeup in the event of loss of inventory, then pumps can be made available through manual actions.

The two redundant PORVs or a depressurized RCS with an open RCS vent is also sufficient to protect the RHR system during the RHR mode of operation for events which cause an increase in system pressure.

PORV Requirements

As designed for the LTOP System, each PORV is signaled to open if the RCS pressure exceeds the limit selected to prevent a condition that is not within the acceptable region provided in the PTLR. The PORVs are opened by coincident actuation of two-of-three RCS pressure channels. The PTLR presents the PORV setpoint for LTOP.

When a PORV is opened in an increasing pressure transient, the release of coolant will cause the pressure increase to slow and then reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

(continued)

BASES

BACKGROUND (continued)

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

For an RCS vent to meet the flow capacity requirement, it requires removing a pressurizer safety valve, removing a PORV's internals or blocking it open, and disabling its block valve in the open position, or similarly establishing a vent by opening an RCS vent path. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 3) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits for all Design Basis Accidents. In MODES 1, 2, and 3, and in MODE 4 with RCS cold leg temperature exceeding the LTOP enable temperature specified in the PTLR, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. At or below the LTOP enable temperature specified in the PTLR, overpressure prevention requires two OPERABLE PORVs or a depressurized RCS and a sufficiently sized RCS vent. Each of these overpressure protection systems has a limited overpressure relief capability.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases as a result of neutron embrittlement. Each time the PTLR curves are revised, the LTOP System must be re-evaluated to ensure its functional requirements can still be met using the RCS relief valve method or the depressurized and vented RCS condition.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The PTLR contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Reference 3 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

Mass Input Type Transients

a. Inadvertent safety injection (SI); or

b. Charging/letdown flow mismatch.

Heat Input Type Transients

a. Inadvertent actuation of pressurizer heaters;

b. Loss of RHR cooling; or

c. Reactor coolant pump (RCP) startup with temperature asymmetry within the RCS or between the RCS and steam generators.

Analyses have determined that the mass input transients are the bounding case for overpressurization of the RCS (Ref. 3). The two categories of mass input transients were analyzed with respect to utilizing a single PORV or an RCS vent ≥ 1.1 square inches as overpressure protection. The inadvertent actuation of a single SI pump provides a larger mass addition to the RCS than isolation of letdown with all three charging pumps operating. A single PORV was determined to be incapable of mitigating the overpressure transient resulting from actuation of a SI pump, but is capable of mitigating the charging/letdown mismatch transient. An RCS vent ≥ 1.1 square inches can mitigate both the inadvertent SI and charging/letdown flow mismatch transients.

Therefore, the following are required during the LTOP MODES to ensure that mass and heat input transients do not occur, which either of the LTOP overpressure protection means cannot handle:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. Rendering all SI pumps incapable of injection into the RCS when the PORVs provide the RCS vent path and rendering all but one SI pump incapable of injection into the RCS when the RCS is depressurized with an RCS vent of ≥ 1.1 square inches;

b. Deactivating the ECCS accumulator discharge motor operated isolation valves in their closed positions; and

c. Disallowing start of an RCP if secondary temperature is more than 50°F above primary temperature in any one loop or pressurizer level ≥ 38%. LCO 3.4.6, "RCS Loops—MODE 4," and LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled," provide this protection.

The Reference 3 analyses demonstrate that either one PORV or the depressurized RCS and RCS vent can maintain RCS pressure below limits with the maximum allowed coolant input capability. Since neither one PORV nor the RCS vent can handle the pressure transient produced from ECCS accumulator injection when RCS temperature is low, the LCO also requires the ECCS accumulators isolated when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

The isolated ECCS accumulators must have their discharge valves closed and the valve power supply removed. The analyses show the effect of ECCS accumulator discharge is over a narrower RCS temperature range (200°F and below) than that of the LCO. Fracture mechanics analyses established the temperature of LTOP Applicability at the LTOP enable temperature specified in the PTLR.

The consequences of a small break loss of coolant accident (LOCA) in LTOP MODE 4 conform to 10 CFR 50.46 and 10 CFR 50, Appendix K (Refs. 4 and 5), requirements by having procedures to manually establish makeup capability.

The events which potentially overpressurize the RHR system during the RHR mode of operation are included within the mass and heat input transients analyzed for LTOP conditions. Therefore, an OPERABLE LTOP System ensures that the RHR system will not be overpressurized during the RHR mode of operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the limit shown in the PTLR. The setpoints are derived by analyses that model the performance of the LTOP System, assuming the limiting LTOP transient for the PORVs of a charging/letdown flow mismatch. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensures the Reference 1 P/T limits will be met and that the RHR system will not be overpressurized.

The PORV setpoints in the PTLR are updated when the revised P/T limits conflict with the LTOP analysis limits. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron irradiation. Revised limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," discuss these examinations.

The PORVs are considered active components. Thus, the failure of one PORV is assumed to represent the worst case, single active failure.

RCS Vent Performance

With the RCS depressurized, analyses show a vent size of 1.1 square inches is capable of mitigating the allowed LTOP overpressure transient. The capacity of a vent this size is greater than the flow of the limiting transient for the LTOP configuration, which maintains RCS pressure less than the maximum pressure on the P/T limit curve. The limiting transient for this LTOP configuration is an SI actuation with one SI pump OPERABLE.

An RCS vent ≥ 1.1 square inches with the RCS depressurized also prevents overpressurization of the RHR system.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The RCS vent size will be re-evaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance.

The RCS vent is passive and is not subject to active failure.

The LTOP System satisfies Criterion 2 of the NRC Policy Statement.

LCO

This LCO requires that the LTOP System is OPERABLE. The LTOP System is OPERABLE when the minimum coolant input and pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires the ECCS accumulators to be isolated. LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," defines SI actuation OPERABILITY for the LTOP MODE 4 small break LOCA.

The elements of the LCO that provide low temperature overpressure mitigation are:

a. Two OPERABLE PORVs and no SI pump capable of injecting into the RCS.

   A PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is set to the limit required by the PTLR and testing proves its ability to open at this setpoint, and motive power is available to the valve and its control circuits.

b. A depressurized RCS and an RCS vent and a maximum of one SI pump capable of injecting into the RCS.

   An RCS vent is OPERABLE when open with an area of ≥ 1.1 square inches.

(continued)

BASES

LCO (continued)

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

The LCO is modified by two Notes. The first Note allows performance of the secondary side hydrostatic tests without the PORVs and RCS vent OPERABLE; however no SI pump may be capable of injecting into the RCS during this test. This exclusion is necessary since a pressure differential of ≤ 800 psid is maintained between the primary and secondary sides during the test. This restricted pressure differential limits the stresses placed on the SG which can cause cladding in the primary channel to separate from the base metal and result in the need for difficult repairs in a high radiation area. To maintain this pressure differential limit, RCS pressure must be increased above the PORV setpoint for LTOP conditions. The test cannot be performed above the LTOP enable temperature since the steam lines may not be able to accommodate the associated thermal expansion if they are heated. Therefore, all three SI pumps must be incapable of injecting into the RCS during these secondary side hydrostatic tests (Ref. 6).

The second Note only requires an ECCS accumulator to be isolated when the accumulator pressure is greater than or equal to the maximum pressure for the existing RCS cold leg temperature allowed in the PTLR. Accumulator pressure below this limit will not overpressurize the RCS beyond analyzed conditions. The accumulator is isolated when the discharge motor operated valve is closed and its associated power supply is removed.

(continued)

BASES (continued)

APPLICABILITY

This LCO is applicable in MODE 4 when any RCS cold leg temperature is less than or equal to the LTOP enable temperature specified in the PTLR or the RHR system is in the RHR operating mode, in MODE 5 when the SG primary system manway and pressurizer manway are closed and secured in position, and in MODE 6 when the reactor vessel head is on and the SG primary system manway and pressurizer manway are closed and secured in position. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above the LTOP enable temperature specified in the PTLR. When the reactor vessel head is off or the SG primary system manway or pressurizer manway are open, overpressurization cannot occur.

LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3, and MODE 4 above the LTOP enable temperature specified in the PTLR.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time allows operator action to mitigate the event.

ACTIONS

A.1

With one or more SI pumps capable of injecting into the RCS and the PORVs provide the RCS vent path, RCS overpressurization is possible. To immediately initiate action to restore restricted coolant input capability to the RCS reflects the urgency of taking action to remove the RCS from this potential condition.

Condition A is modified by a Note which states that this condition is only applicable to LCO 3.4.12.a (i.e., when the PORVs provide the RCS vent path).

(continued)

BASES

ACTIONS

B.1 (continued)

In MODE 4 when any RCS cold leg temperature is less than or equal to the LTOP enable temperature specified in the PTLR, with one required PORV inoperable, the PORV must be restored to OPERABLE status within a Completion Time of 7 days. Two PORVs are required to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time considers that only one PORV is required to mitigate an overpressure transient and that the likelihood of an active failure of the remaining valve path during this time period is very low.

Condition B is modified by a Note which states that this condition is only applicable to LCO 3.4.12.a (i.e., when the PORVs provide the RCS vent path).

C.1

The consequences of operational events that will overpressurize the RCS are more severe at lower temperature (Ref. 7). Thus, with one of the two PORVs inoperable in MODE 5 with the SG primary system manway and pressurizer manway closed and secured in position, or in MODE 6 with the head on and the SG primary system manway and pressurizer manway closed and secured in position, the PORV must be restored to OPERABLE status in 72 hours. Restoring the PORV to OPERABLE status provides required redundancy.

The Completion Time of 72 hours to restore the PORV to OPERABLE status represents a reasonable time to investigate and repair several types of relief valve failures without exposure to a lengthy period with only one PORV to protect against overpressure events.

Condition C is modified by a Note which states that this condition is only applicable to LCO 3.4.12.a (i.e., when the PORVs provide the RCS vent path).

(continued)

BASES

ACTIONS (continued)

D.1

With two or more SI pumps capable of injecting into the RCS and the RCS is depressurized with an RCS vent of ≥ 1.1 square inches, RCS overpressurization is possible.

To immediately initiate action to restore restricted coolant input capability to the RCS reflects the urgency of taking action to the RCS from this potential condition.

Condition D is modified by a Note which states that this condition is only applicable to LCO 3.4.12.b (i.e., when there is a RCS vent path ≥ 1.1 square inches.

E.1, F.1, and F.2

An unisolated ECCS accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is greater than or equal to the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If isolation is needed and cannot be accomplished in 1 hour, Required Action F.1 and Required Action F.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature to greater than the LTOP enable temperature specified in the PTLR, a maximum accumulator pressure of 800 psig (relief valve setpoint) cannot exceed the LTOP limits if the accumulators are fully injected. Depressurizing the accumulators below the LTOP limit from the PTLR also gives this protection.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

G.1 and G.2

At least one charging pump must be in the pull-stop position within 1 hour and the RCS must be depressurized and a vent must be established within 8 hours when:

a. Both required PORVs are inoperable; or

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

b. A Required Action and associated Completion Time of Condition A, B, C, or F is not met; or

c. The LTOP System is inoperable for any reason other than Condition A, B, C, or E.

The Completion Time of one hour to restrict the coolant input capability to the RCS considers the relatively low probability of an overpressure event during this time period and provides the operator time to render a charging pump incapable of injecting by placing it in the pull-stop position. Only one disabling device is required since there is a relatively small probability of an inadvertent charging pump actuation during the 8 hours before RCS depressurization is achieved and a vent established. The disabling of a charging pump is necessary since RV 203 cannot mitigate a charging/letdown mismatch event if RHR is providing decay heat removal above MODE 5 and three charging pumps are operating.

The vent must be sized ≥ 1.1 square inches to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel and to protect the RHR system from overpressurization.

The Completion Time of 8 hours to depressurize the RCS and establish a vent considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, all SI pumps must be verified incapable of injecting into the RCS when the PORVs provide the RCS vent path (LCO 3.4.12.a) and a minimum of two SI pumps must be verified incapable of injecting into the RCS when the RCS is depressurized and an RCS vent ≥ 1.1 square inches is established (LCO 3.4.12.b). The SI pumps are rendered incapable of injecting into the RCS through removing the power from the pumps by racking the breakers out under administrative control. An alternate method of LTOP control may be employed using at least two independent means to prevent a pump start such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the following:

a. placing the pump control switch in the pull-stop position and closing at least one valve in the discharge flow path;

b. locking closed a manual isolation valve in the injection path; or

c. closing a motor operated isolation valve in the injection path and removing the AC power source.

The flowpaths through the test connections associated with the ECCS accumulator check valves (i.e., lines containing air operated valves 839A, 839B, 840A, and 840B) and the ECCS accumulator fill lines (i.e., lines containing air operated valves 835A and 835B) do not have to be isolated for this SR since the potential mass addition from a single SI pump through these six lines is limited by the installed orifices to less than that assumed for the charging/letdown mismatch analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3 (continued)

The ECCS accumulator motor operated isolation valves can be verified closed by use of control board indication for valve position. This verification is only required when the accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR. If the accumulator pressure is less than this limit, no verification is required since the accumulator cannot pressurize the RCS to or above the PORV setpoint.

The Frequency of 12 hours is sufficient, considering other indications and alarms available to the operator in the control room, to verify the required status of the equipment. The Frequency of every 12 hours thereafter for SR 3.4.12.3 ensures that the ECCS accumulator motor operated isolation valves are maintained closed and do not result in a potential LTOP actuation.

SR 3.4.12.4

The RCS vent of ≥ 1.1 square inches is proven OPERABLE by verifying its open condition either:

a. Once every 12 hours for a valve that cannot be locked.

b. Once every 31 days for a valve that is locked, sealed, or secured in position. A removed pressurizer safety valve fits this category.

The passive vent arrangement must only be open to be OPERABLE. This Surveillance is required to be performed if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12.b.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.5

The PORV block valve must be verified open every 72 hours to provide the flow path for each required PORV to perform its function when actuated. The valve may be remotely verified open in the main control room. This Surveillance is performed if the PORV satisfies the LCO.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required to be removed, and the manual operator is not required to be locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation.

The 72 hour Frequency is considered adequate in view of other administrative controls available to the operator in the control room, such as valve position indication, that verify that the PORV block valve remains open.

SR 3.4.12.6

Performance of a CHANNEL OPERATIONAL TEST (COT) is required every 31 days on each required PORV to verify and, as necessary, adjust its lift setpoint. The COT will verify the setpoint is within the allowed maximum limits in the PTLR. PORV actuation could depressurize the RCS and is therefore not required.

A Note has been added indicating that this SR is required to be performed within 12 hours after decreasing RCS cold leg temperature to less than or equal to the LTOP enable temperature specified in the PTLR if it has not been performed within the previous 31 days. Depending on the cooldown rate, the COT may not have been performed before entry into the LTOP MODES. The test must be performed within 12 hours after entering the LTOP MODES. The 12 hours considers the unlikelihood of a low temperature overpressure event during this time.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.7

Verification once within 12 hours and every 31 days thereafter that power is removed from each ECCS accumulator motor operated isolation valve ensures that at least two independent actions must occur before the accumulator is capable of injecting into the RCS. Since power is removed under administrative control and valve position is verified every 12 hours, the performance of this surveillance once within 12 hours and every 31 days thereafter will provide assurance that power is removed.

This SR is modified by a Note which states that the Surveillance is only required when the accumulator pressure is greater than or equal to the maximum RCS pressure for the existing cold leg temperature allowed in the PTLR. If the accumulator pressure is below this limit, the LTOP limit cannot be exceeded and the surveillance is not required.

SR 3.4.12.8

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required every 24 months to adjust the whole channel so that it responds and the valve opens within the required range and accuracy to known input.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-11, "NRC Position on Embrittlement of Reactor Vessel Materials and its Impact on Plant Operations."
3. UFSAR, Section 5.2.2.
4. 10 CFR 50, Section 50.46.
5. 10 CFR 50, Appendix K.

(continued)

BASES

REFERENCES (continued)

6. Letter from D. L. Ziemann, NRC, to L. D. White, RG&E, Subject: "Issuance of Amendment No. 27 to Provisional Operating License No. DPR-18," dated July 26, 1979.

7. Generic Letter 90-06, "Resolution of Generic Issue 70, "Power-Operated Relief Valve and Block Valve Reliability," and Generic Issue 94, "Additional Low-Temperature Overpressure Protection for Light-Water Reactors."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.

Atomic Industry Forum (AIF) GDC 16 (Ref. 1) requires that means be provided to detect significant uncontrolled leakage from the reactor coolant pressure boundary (RCPB). AIF-GDC 34 also requires that the RCPB be designed to reduce the probability of rapid propagation failures. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE. The leakage detection systems support these requirements by both detecting RCS LEAKAGE and identifying the location of its source. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the plant and the public.

(continued)

BASES

BACKGROUND (continued)

A limited amount of leakage inside containment is expected from auxiliary systems (e.g. component cooling water) that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event (Ref. 2).

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The safety analysis for an event resulting in steam discharge to the atmosphere assumes a 0.5 gpm primary to secondary LEAKAGE as the initial condition. The leakage contaminates the secondary fluid.

The UFSAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is only briefly released via safety valves and the majority is steamed to the condenser. The assumed 0.5 gpm primary to secondary LEAKAGE is relatively inconsequential.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The SLB outside of containment is more limiting for site radiation releases. The safety analysis for the SLB accident assumes 0.5 gpm primary to secondary LEAKAGE in one generator as an initial condition. The dose consequences resulting from the SLB accident outside of containment are well within the limits defined in 10 CFR 100 or the staff approved licensing basis (i.e., a small fraction of these limits). However, a lower LEAKAGE limit is assumed for all SLBs to prevent a coincident SGTR due to the large stresses placed on the SG tubes as a result of the rapid cooldown and depressurization. These stress calculations conservatively assume a tube with a 0.4 inch long through-wall crack in a location with 40% local wall thinning. The analyses demonstrate that the integrity of the selected tube is maintained with sufficient margin after the SLB. The assumed through-wall crack of 0.4 inches corresponds to 0.1 gpm leakage under normal operating conditions (Ref. 4). Therefore, the primary to secondary LEAKAGE is limited to 0.1 gpm per SG.

The RCS operational LEAKAGE satisfies Criterion 2 of the NRC Policy Statement.

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

(continued)

BASES

LCO (continued)

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of identified LEAKAGE and is well within the capability of a charging pump operating at its low speed setting. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, LEAKAGE through two in-series PIVs, and primary to secondary LEAKAGE, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal return (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through Each Steam Generator (SG)

Total primary to secondary LEAKAGE amounting to 0.1 gpm through each SG produces acceptable offsite doses and tube stresses in the SLB accident analysis. Violation of this LCO could exceed the offsite dose limits for this accident or result in a coincident SGTR. Primary to secondary LEAKAGE must be included in the total allowable limit for identified LEAKAGE. The SGs shall also be OPERABLE in accordance with the Steam Generator Tube Surveillance Program.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 or 6, the temperature is ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation is much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the in-series PIVs in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any RCS pressure boundary LEAKAGE exists, or if the Required Action of Condition A cannot be completed within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. The reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE which is not allowed by this LCO, would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance. Primary to secondary LEAKAGE is also measured by performance of an RCS water inventory balance in conjunction with effluent monitoring within the secondary steam and feedwater systems.

The RCS water inventory balance must be performed with the RCS at steady state operating conditions. Therefore, this SR is required to be performed once during the initial 12 hours of steady state operation and every 72 hours thereafter.

Steady state operation is required to perform a proper inventory balance; calculations during maneuvering are not useful and a Note requires the Surveillance to be met when steady state is established. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and volume control tank levels, makeup and letdown, and RCP seal injection and return flows.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 (continued)

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

SR 3.4.13.2

This SR provides the means necessary to determine SG OPERABILITY in an operational MODE. The requirement to demonstrate SG tube integrity in accordance with the Steam Generator Tube Surveillance Program emphasizes the importance of SG tube integrity, even though this Surveillance cannot be performed at normal operating conditions.

REFERENCES

1. Atomic Industry Forum (AIF) GDC 16, Issued for comment July 10, 1967.

2. Generic Letter 84-04, "Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops."

3. UFSAR, Section 15.6.3.

4. Letter from R. A Purple, NRC, to L. D. White, RG&E, Subject: "Issuance of Amendment No. 7 to Provisional Operating License No. DPR-18," dated May 14, 1975.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and Atomic Industry Forum (AIF) GDC 53 (Refs. 1, 2, and 3), define RCS PIVs as any two normally closed valves in-series within the reactor coolant pressure boundary (RCPB), which separate the high pressure RCS from an attached low pressure system. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety.

The PIV leakage limit applies to each individual valve. Leakage through both in-series PIVs for a given line must be included as part of the identified LEAKAGE, governed by LCO 3.4.13, "RCS Operational LEAKAGE." This is true during operation only when the loss of RCS mass through in-series valves is determined by a water inventory balance (SR 3.4.13.1) or other confirmatory tests. A known component of the identified LEAKAGE before operation begins is the least of the individual leak rates determined for leaking series PIVs during the required surveillance testing; leakage measured through one PIV in a line is not RCS operational LEAKAGE if the other is leaktight. Prior to the required surveillance testing (SR 3.4.14.1) and water inventory balance (SR 3.4.13.1) in MODES 3 and 4, any leakage through the PIVs is considered unidentified LEAKAGE.

Although this specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment (i.e., intersystem LOCA), an unanalyzed accident, that could degrade the ability for low pressure injection.

(continued)

BASES

BACKGROUND (continued)

The basis for this LCO is the 1975 NRC "Reactor Safety Study" (Ref. 4) that identified potential intersystem LOCAs as a significant contributor to the risk of core damage. A subsequent study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs and to identify which configurations dominate the risk profile for intersystem LOCA potential. In response to Reference 6, a plant specific evaluation of intersystem LOCAs was performed to identify the most risk significant configurations.

Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

APPLICABLE SAFETY ANALYSES

Reference 4 identified potential intersystem LOCAs as a significant contributor to the risk of core damage. The dominant accident sequence in the intersystem LOCA category as identified by Reference 4 was the failure of the low pressure portion of the RHR System outside of containment. This accident is the result of a postulated failure of the PIVs, which are part of the RCPB, and the subsequent pressurization of the RHR System downstream of the PIVs from the RCS. Because the low pressure portion of the RHR System is designed for 600 psig, overpressurization failure of the RHR low pressure line would result in a LOCA outside containment and subsequent increased risk of core damage.

Reference 5 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA. In response to Reference 6, a plant specific evaluation of intersystem LOCAs was performed. PIVs in the following systems connected to the RCS were evaluated:

a. residual heat removal (RHR);

b. safety injection (SI); and

c. chemical and volume control.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The evaluation of intersystem LOCAs concluded that several configurations identified in References 4 and 5 existed in the RHR and SI systems. The PIV configurations in the Chemical and Volume Control System were not identified as being risk significant due to the installed orifices in the letdown piping and the use of piping designed to RCS pressure conditions from the discharge of the positive displacement pumps to containment (Ref. 7).

The PIVs identified in the SI and RHR Systems are listed below:

853A	RHR Inlet Check Valve to Reactor Vessel Core Deluge
853B	RHR Inlet Check Valve to Reactor Vessel Core Deluge
867A	SI Pump Discharge and Accumulator A Check Valve to RCS Cold Leg B
867B	SI Pump Discharge and Accumulator B Check Valve to RCS Cold Leg A
877A	SI Pump Discharge Check Valve to RCS Hot Leg B
877B	SI Pump Discharge Check Valve to RCS Hot Leg A
878A	SI Pump Discharge Isolation MOV to RCS Hot Leg B
878C	SI Pump Discharge Isolation MOV to RCS Hot Leg A
878F	SI Pump Discharge Check Valve to RCS Hot Leg B
878G	SI Pump Discharge Check Valve to RCS Cold Leg B
878H	SI Pump Discharge Check Valve to RCS Hot Leg A
878J	SI Pump Discharge Check Valve to RCS Cold Leg A

RCS PIV leakage satisfies Criterion 2 of the NRC Policy Statement.

LCO

RCS PIV leakage is identified LEAKAGE into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken. This LCO only applies to those PIVs which are determined to be in the most risk significant configurations (Ref. 7) as listed in Applicable Safety Analysis. The remaining PIVs are governed by LCO 3.4.13, "RCS Operational LEAKAGE" and LCO 3.6.3, "Containment Isolation Boundaries."

(continued)

BASES

LCO (continued)

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm. A leakage rate limit based on valve size is used since this is superior to a single allowable value (Ref. 8).

Reference 9 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases, the observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one half power.

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized.

In MODES 5 or 6, the temperature is ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and isolation failures are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

The Actions are modified by two Notes. Note 1 provides clarification that each flow path allows separate entry into a Condition. This is allowed based upon the functional independence of the flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system operability, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

A leaking flow path must be isolated by two valves. Required Actions A.1 and A.2 are modified by a Note that the valves used for isolation must meet the same leakage requirements as the PIVs and must be within the RCPB or the high pressure portion of the system.

Required Action A.1 requires that isolation of the affected flow path with one valve must be performed within 4 hours. Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected system if leakage cannot be reduced. The 4 hour Completion Time allows the actions and restricts operation with leaking isolation valves.

Required Action A.2 specifies that the double isolation barrier of two valves be restored by closing some other valve qualified for isolation. The use of a valve other than the previously leaking PIV must include consideration that the plant may no longer be in an analyzed condition. The 72 hour Completion Time after exceeding the limit considers the time required to complete the Action and the low probability of a second valve failing during this time period.

B.1 and B.2

If leakage cannot be reduced, the system isolated, or the other Required Actions accomplished, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This Action may reduce the leakage due to reduced RCS pressure while reducing the potential for a LOCA outside the containment. The allowed Completion Times are reasonable based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 and SR 3.4.14.2

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 and Required Action A.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve and should be based on an RCS pressure of ± 20 psig of normal system operating pressure. Leakage testing requires a stable pressure condition.

For multiple in-series PIVs, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other in-series valve meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

Testing of the check valves (877A, 877B, 878F, and 878H) and the motor operated valves (878A and 878C) identified as PIVs in the SI hot leg injection lines is to be performed at least once every 40 months. This surveillance interval is allowed since the two SI hot leg injection lines are maintained closed to address pressurized thermal shock (PTS) concerns. Each injection line is isolated by two check valves and one motor operated valve in-series which must all fail to create the potential for an intersystem LOCA. Testing of the remaining RCS PIVs in the SI and RHR systems is to be performed every 24 months, a typical refueling cycle. The 24 month Frequency is consistent with 10 CFR 50.55a(g) (Ref. 10) as contained in the Inservice Testing Program, is within the frequency allowed by the American Society of Mechanical Engineers (ASME) Code, Section XI (Ref. 9), and is based on the need to perform such surveillances under the conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 and SR 3.4.14.2 (continued)

In addition to the periodic testing requirements, testing must be performed once after the valve has been opened by flow, exercised, or had maintenance performed on it to ensure tight reseating. This maintenance does not include minor activities such as packing adjustments which do not affect the leak tightness of the valve. PIVs disturbed in the performance of this Surveillance should also be tested unless documentation shows that an infinite testing loop cannot practically be avoided. Testing must be performed within 24 hours after the valve has been reseated. A limit of 24 hours is a reasonable and practical time limit for performing this test after opening or reseating a valve.

The leakage limit is to be met at the RCS pressure associated with MODES 1 and 2. This permits leakage testing at high differential pressures with stable conditions not possible in the MODES with lower pressures.

Entry into MODES 3 and 4 is allowed to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance.

REFERENCES

1. 10 CFR 50.2.

2. 10 CFR 50.55a(c).

3. Atomic Industry Forum (AIF) GDC 53, Issued for comment July 10, 1967.

4. WASH-1400 (NUREG-75/014), "An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," Appendix V, October 1975.

5. NUREG-0677, "The Probability of Intersystem LOCA: Impact Due to Leak Testing and Operational Changes," May 1980.

6. Generic Letter, "LWR Primary Coolant System Pressure Isolation Valves," dated February 23, 1980.

(continued)

BASES

REFERENCES (continued)

7. Letter from D. M. Crutchfield, NRC, to J. E. Maier, RG&E, Subject: "Order for Modification of License Concerning Primary Coolant System Pressure Isolation Valves," dated April 20, 1981.

8. EG&G Report, EGG-NTAP-6175.

9. ASME, Boiler and Pressure Vessel Code, Section XI.

10. 10 CFR 50.55a(g).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

Atomic Industry Forum (AIF) GDC 16 (Ref. 1) requires that means be provided to detect significant uncontrolled leakage from the reactor coolant pressure boundary (RCPB). AIF-GDC 34 (Ref. 1) also requires that the RCPB be designed to reduce the probability of rapid propagation failures. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE. The leakage detection systems support these requirements by both detecting RCS LEAKAGE and identifying the location of its source.

Industry practice has shown that small water flow changes can be readily detected in contained volumes by monitoring changes in water level or in the operating frequency of a pump. The containment sump used to collect unidentified LEAKAGE (i.e., containment sump A) is monitored for level and sump pump actuation and can measure approximately a 2.0 gpm leak in one hour. This sensitivity is acceptable for detecting increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. The particulate monitor (R-11) can detect a leak of 0.013 gpm within 20 minutes assuming the presence of corrosion products. The gaseous monitor (R-12) can detect a leak of 2.0 to 10.0 gpm within 1 hour and is considered a backup to the particulate monitor. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE.

(continued)

BASES

BACKGROUND (continued)

Alternative means also exist to monitor RCS LEAKAGE inside containment. These include humidity detectors, air temperature and pressure monitoring, and condensate flow rate from the air coolers. The capability of these systems to detect RCS leakage is influenced by several factors including containment free volume and detector location. These systems are most useful as alarms or indirect indicating devices available to the operators and are not required by this LCO (Ref. 2).

The leakage detection systems are also used to support identification of leakage from open systems found in containment. This includes service water and fire service water systems. Leakage from these systems is required to be monitored in response to IE Bulletin No. 80-24 (Ref. 3).

APPLICABLE SAFETY ANALYSES

The asymmetric loads produced by the postulated breaks are the result of an assumed pressure imbalance, both internal and external to the RCS. The internal asymmetric loads result from a rapid decompression that cause large transient pressure differentials across the core barrel and fuel assemblies. The external asymmetric loads result from the rapid depressurization of annulus regions, such as the annulus between the reactor vessel and the shield wall, and cause large transient pressure differentials to act on the vessel. These asymmetric loads could damage RCS supports, core cooling equipment or core internals. This concern was first identified as Multiplant Action (MPA) D-10 and subsequently as Unresolved Safety Issue (USI) 2, "Asymmetric LOCA Loads" (Ref. 4).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The resolution of USI-2 for Westinghouse PWRs was use of fracture mechanics technology for RCS piping > 10 inches diameter (Ref. 5). This technology became known as leak-before-break (LBB). Included within the LBB methodology was the requirement to have leakage detection systems capable of detecting a 1.0 gpm leak within four hours. This leakage rate is designed to ensure that adequate margins exist to detect leaks in a timely manner during normal operating conditions. The use of LBB for Ginna Station is documented in Reference 6.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the plant and the public. Required corrective actions are provided in LCO 3.4.13, RCS Operational LEAKAGE. The capability of the leakage detection systems was evaluated by the NRC in Reference 7.

RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.

LCO

One method of protecting against large RCS LEAKAGE derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

(continued)

BASES

LCO (continued)

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump A monitor (level or pump actuation from either sump A pump), in combination with a gaseous (R-12) or particulate (R-11) radioactivity monitor provides an acceptable minimum. Alternatively, the plant vent gaseous (R-14) or particulate (R-13) monitors may be used in place of R-12 and R-11, respectively, provided that a flowpath through normally closed valve 1590 is available and R-14A is OPERABLE.

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

A.1.1, A.1.2, and A.2

With the required containment sump A monitor inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere radioactivity monitor will provide indications of changes in leakage. In addition to an OPERABLE gaseous or particulate atmosphere monitor, the containment air cooler condensate collection system must be verified to be OPERABLE within 24 hours, or the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage. The use of the gaseous monitor (R-12) is acceptable due to the increased frequency of performing SR 3.4.13.1 or the use of the containment air cooler condensate collection system.

(continued)

BASES

ACTIONS

A.1.1, A.1.2, and A.2 (continued)

The containment air cooler condensate collection system is OPERABLE if the flow paths from all four containment air coolers to their respective collection tanks are available and a CHANNEL CALIBRATION of the monitor has been performed within the last 24 months. The containment air cooler condensate collection system is provided as an option for detecting RCS leakage since SR 3.4.13.1 is not performed until after 12 hours of steady state operation. Therefore, this collection system can be used during MODE changes if the containment sump monitor is inoperable.

Restoration of the required sump monitor to OPERABLE status within a Completion Time of 30 days is required to regain the function after the monitor's failure. This time is acceptable, considering the Frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

Required Actions A.1.1, A.1.2, and A.2 are modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the containment sump monitor is inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

B.1.1, B.1.2, and B.2.1

With both gaseous (R-12) and particulate (R-11) containment atmosphere radioactivity monitoring instrumentation channels inoperable (and their alternatives R-13 and R-14), alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

With a grab sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment atmosphere radioactivity monitors. The 24 hour interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time recognizes that at least one other form of leakage detection is available.

(continued)

BASES

ACTIONS

B.1.1, B.1.2, and B.2.1 (continued)

Required Actions B.1.1, B.1.2, and B.2 are modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the gaseous and particulate containment atmosphere radioactivity monitors are inoperable. This allowance is provided because other instrumentation is available to monitor for RCS LEAKAGE.

C.1.1, C.1.2, C.2.1, and C.2.2

With the required containment sump monitor and the particulate containment atmosphere radioactivity monitor (R-11) inoperable, the only installed means of detecting leakage is the gaseous containment atmosphere radioactivity monitor (R-12). This condition does not provide a diverse means of leakage detection. Also, the gaseous monitor can only measure between a 2.0 and 10.0 gpm leak within 1 hour which may not meet the 1.0 gpm in less than four hours detection rate required by Generic Letter 84-04 (Ref. 5).

The Required Actions are to analyze grab samples of the containment atmosphere or perform RCS water inventory balance, SR 3.4.13.1, at a frequency of 24 hours. The combination of the gaseous monitor and either the periodic grab samples or RCS inventory balance provide information that is adequate to detect leakage. Restoration of either of the inoperable monitors to OPERABLE status within 30 days is required to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a reduced configuration for a lengthy period of time.

Required Actions C.1.1, C.1.2, C.2.1, and C.2.2 are modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the containment sump monitor and particulate containment atmosphere radioactivity monitor are inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If a Required Action of Condition A, B, or C cannot be met, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

With all required monitors inoperable, no automatic means of monitoring leakage are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

This SR requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.15.2

This SR requires the performance of a CHANNEL OPERATIONAL TEST (COT) on the required containment atmosphere radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 92 days considers instrument reliability, and operating experience has shown that it is proper for detecting degradation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.15.3 and SR 3.4.15.4

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 24 months considers channel reliability and operating experience has proven that this Frequency is acceptable.

REFERENCES

1. Atomic Industry Forum (AIF) GDC 16 and 34, Issued for comment July 10, 1967.
2. Regulatory Guide 1.45.
3. IE Bulletin No. 80-24, "Prevention of Damage Due to Water Leakage Inside Containment."
4. NUREG-0609, "Asymmetric Blowdown Loads on PWR Primary Systems," 1981.
5. Generic Letter 84-04, "Safety Evaluation of Westinghouse Topical Reports Dealing With Elimination of Postulated Pipe Breaks in PWR Primary Main Loops."
6. Letter from D. C. DiIanni, NRC, to R. W. Kober, RG&E, Subject: "Generic Letter 84-04," dated September 9, 1985.
7. NUREG-0821, "Integrated Plant Safety Assessment, Systematic Evaluation Program, R. E. Nuclear Power Plant," December 1982.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The maximum dose to the whole body and the thyroid that an individual at the site boundary can receive for 2 hours during an accident is specified in 10 CFR 100 (Ref. 1). The limits on specific activity ensure that the doses are held to a small fraction of the 10 CFR 100 limits during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a steam generator tube rupture (SGTR) accident.

The specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity are provided in the SRs. DOSE EQUIVALENT I-131 is calculated using Table E-7 of Regulatory Guide 1.109 (Ref. 2). The allowable levels are intended to limit the 2 hour dose at the site boundary to a small fraction of the 10 CFR 100 dose guideline limits. The limits in the LCO are standardized, based on parametric evaluations of offsite radioactivity dose consequences for typical site locations.

The parametric evaluations showed the potential offsite dose levels for a SGTR accident were an appropriately small fraction of the 10 CFR 100 dose guideline limits. Each evaluation assumes a broad range of site applicable atmospheric dispersion factors in a parametric evaluation.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensures that the resulting 2 hour doses at the site boundary will not exceed a small fraction of the 10 CFR 100 dose guideline limits following a SGTR accident. The SGTR safety analysis (Ref. 3) assumes the specific activity of the reactor coolant at the LCO limit and an existing reactor coolant steam generator (SG) tube leakage rate of 0.5 gpm.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The analysis for the SGTR accident establishes the acceptance limits for RCS specific activity. Reference to this analysis is used to assess changes to the plant that could affect RCS specific activity, as they relate to the acceptance limits.

The analysis is for two cases of reactor coolant specific activity (Ref. 4). One case assumes specific activity at 1.0 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the I-131 activity in the reactor coolant by a factor of about 500 for a duration of four hours immediately after the accident. The second case assumes the initial reactor coolant iodine activity at 60.0 μCi/gm DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. In both cases, the noble gas activity in the reactor coolant assumes 1% failed fuel, which closely equals the LCO limit of 100/E μCi/gm for gross specific activity.

The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal or an RCS overtemperature ΔT signal. The analysis also assumes a loss of offsite power at the same time as the reactor trip following the SGTR event.

The coincident loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG atmospheric relief valves and the main steam safety valves. This steam release continues for eight hours until the residual heat removal system is utilized for cooldown purposes. All noble gas activity in the RCS which is transported to the secondary system by the tube rupture is assumed to be immediately released to the atmosphere. The unaffected SG removes core decay heat by venting steam to the atmosphere until the initial cooldown ends and the RCS system pressure stabilizes below the relief valve setpoint.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The safety analysis shows the radiological consequences of an SGTR accident are within a small fraction of the Reference 1 dose guideline limits. Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed the limits shown in Figure 3.4.16-1 for more than 7 days.

The increased permissible iodine levels shown in Figure 3.4.16-1 are acceptable because of the low probability of a SGTR accident occurring during the established 7 day time limit. The occurrence of an SGTR accident at these permissible levels could increase the site boundary dose levels, but they would still be within 10 CFR 100 dose guideline limits.

RCS specific activity satisfies Criterion 2 of the NRC Policy Statement.

LCO

The specific iodine activity is limited to 1.0 μCi/gm DOSE EQUIVALENT I-131, and the gross specific activity in the reactor coolant is limited to 100/E μCi/gm (where E is the average disintegration energy of the sum of the average beta and gamma energies of the coolant nuclides). The limit on DOSE EQUIVALENT I-131 ensures the 2 hour thyroid dose to an individual at the site boundary during the Design Basis Accident (DBA) will be a small fraction of the allowed thyroid dose. The limit on gross specific activity ensures the 2 hour whole body dose to an individual at the site boundary during the DBA will be a small fraction of the allowed whole body dose.

The SGTR accident analysis (Ref. 3) shows that the 2 hour site boundary dose levels are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of an SGTR, lead to site boundary doses that exceed the 10 CFR 100 dose guideline limits.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS average temperature ≥ 500°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and gross specific activity are necessary to contain the potential consequences of an SGTR to within the acceptable site boundary dose values.

For operation in MODE 3 with RCS average temperature < 500°F, and in MODES 4 and 5, the release of radioactivity in the event of a SGTR is unlikely since the saturation pressure of the reactor coolant is below the lift pressure settings of the main steam safety valves.

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 8 hours must be taken to demonstrate that the limits of Figure 3.4.16-1 are not exceeded. The Completion Time of 8 hours is required to obtain and analyze a sample. Sampling is done to continue to provide a trend.

The DOSE EQUIVALENT I-131 must be restored to within limits within 7 days if the limit violation resulted from normal iodine spiking.

Required Action A.1 is modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the DOSE EQUIVALENT I-131 is greater than the LCO limit and within the acceptable range of Figure 3.4.16-1. This allowance is provided because of the significant conservatism included in the LCO limit. Also, reducing the DOSE EQUIVALENT I-131 to within limits is accomplished through use of the Chemical and Volume Control System (CVCS) demineralizers. This cleanup operation parallels plant restart following a reactor trip which frequently results in iodine spikes due to the large step decrease in reactor power level and RCS pressure excursion. The cleanup operation can normally be accomplished within the LCO Completion Time of 7 days.

(continued)

BASES

ACTIONS (continued)

B.1

If a Required Action and the associated Completion Time of Condition A is not met or if the DOSE EQUIVALENT I-131 specific activity is in the unacceptable region of Figure 3.4.16-1, the reactor must be brought to MODE 3 with RCS average temperature < 500°F within 8 hours. The change within 8 hours to MODE 3 and RCS average temperature < 500°F lowers the saturation pressure of the reactor coolant below the setpoints of the main steam safety valves and prevents automatically venting the SG to the environment in an SGTR event. The Completion Time of 8 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

C.1

If the gross specific activity is not within limit, the change within 8 hours to MODE 3 and RCS average temperature < 500°F lowers the saturation pressure of the reactor coolant below the setpoints of the main steam safety valves and prevents automatically venting the SG to the environment in an SGTR event. The allowed Completion Time of 8 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

This SR requires performing a gamma isotopic analysis as a measure of the gross specific activity of the reactor coolant at least once every 7 days. While basically a quantitative measure of radionuclides with half lives longer than 15 minutes, excluding iodines, this measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in gross specific activity.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1 (continued)

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The Surveillance is applicable in MODES 1 and 2, and in MODE 3 with $T_{avg} \geq 500°F$. The 7 day Frequency considers the unlikelihood of a gross fuel failure during this time.

SR 3.4.16.2

This SR is only performed in MODE 1 to ensure iodine remains within limits during normal operation and following fast power changes when fuel failure is more likely to occur. The 14 day Frequency is adequate to trend changes in the iodine activity level, considering gross activity is monitored every 7 days. The Frequency, between 2 and 10 hours after a power change ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following fuel failure; samples at other times would provide inaccurate results.

SR 3.4.16.3

A radiochemical analysis for $\bar{E}$ determination is required within 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for at least 48 hours and every 184 days (6 months) thereafter. This ensures that the radioactive materials are at equilibrium so the analysis for $\bar{E}$ is representative and not skewed by a crud burst or other similar abnormal event. The $\bar{E}$ determination directly relates to the LCO and is required to verify plant operation within the specified gross activity LCO limit. The analysis for $\bar{E}$ is a measurement of the average energies per disintegration for isotopes with half lives longer than 15 minutes, excluding iodines. The Frequency recognizes $\bar{E}$ does not change rapidly.

This SR is modified by a Note that indicates sampling is only required to be performed in MODE 1 such that equilibrium conditions are present during the sample.

(continued)

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.1 Accumulators

LCO 3.5.1 Two ECCS accumulators shall be OPERABLE.

APPLICABILITY: MODES 1 and 2,
MODE 3 with pressurizer pressure > 1600 psig.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One accumulator inoperable due to boron concentration not within limits.	A.1 Restore boron concentration to within limits.	72 hours
B. One accumulator inoperable for reasons other than Condition A.	B.1 Restore accumulator to OPERABLE status.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Reduce pressurizer pressure to ≤ 1600 psig.	6 hours 12 hours
D. Two accumulators inoperable.	D.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify each accumulator motor operated isolation valve is fully open.	12 hours
SR 3.5.1.2	Verify borated water volume in each accumulator is ≥ 1126 cubic feet (50%) and ≤ 1154 cubic feet (82%).	12 hours
SR 3.5.1.3	Verify nitrogen cover pressure in each accumulator is ≥ 700 psig and ≤ 790 psig.	12 hours
SR 3.5.1.4	Verify boron concentration in each accumulator is ≥ 2100 ppm and ≤ 2600 ppm.	31 days on a STAGGERED TEST BASIS
SR 3.5.1.5	Verify power is removed from each accumulator motor operated isolation valve operator when pressurizer pressure is > 1600 psig.	31 days

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 ECCS — MODES 1, 2, and 3

LCO 3.5.2 Two ECCS trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

---------------------------NOTES--------------------------

1. In MODE 3, both safety injection (SI) pump flow paths may be isolated by closing the isolation valves for up to 2 hours to perform pressure isolation valve testing per SR 3.4.14.1. Power may be restored to motor operated isolation valves 878B and 878D for up to 12 hours for the purpose of testing per SR 3.4.14.1 provided that power is restored to only one valve at a time.

2. Operation in MODE 3 with ECCS pumps declared inoperable pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is allowed for up to 4 hours or until the temperature of both RCS cold legs exceeds 375°F, whichever comes first.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One train inoperable. AND At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available.	A.1 Restore train to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours
C. Two trains inoperable.	C.1 Enter LCO 3.0.3	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify the following valves are in the listed position. Number Position Function 825A Open RWST Suction to SI Pumps 825B Open RWST Suction to SI Pumps 826A Closed BAST Suction to SI Pumps 826B Closed BAST Suction to SI Pumps 826C Closed BAST Suction to SI Pumps 826D Closed BAST Suction to SI Pumps 851A Open Sump B to RHR Pumps 851B Open Sump B to RHR Pumps 856 Open RWST Suction to RHR Pumps 878A Closed SI Injection to RCS Hot Leg 878B Open SI Injection to RCS Cold Leg 878C Closed SI Injection to RCS Hot Leg 878D Open SI Injection to RCS Cold Leg 896A Open RWST Suction to SI and Containment Spray 896B Open RWST Suction to SI and Containment Spray	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.2	Verify each ECCS manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.5.2.3	Verify each breaker or key switch, as applicable, for each valve listed in SR 3.5.2.1, is in the correct position.	31 days
SR 3.5.2.4	Verify each ECCS pump's developed head at the test flow point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.5.2.5	Verify each ECCS automatic valve in the flow path that is not locked, sealed, or otherwise secured in position actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.5.2.6	Verify each ECCS pump starts automatically on an actual or simulated actuation signal.	24 months
SR 3.5.2.7	Verify, by visual inspection, each RHR containment sump suction inlet is not restricted by debris and the containment sump screen shows no evidence of structural distress or abnormal corrosion.	24 months

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.3 ECCS — MODE 4

LCO 3.5.3 One ECCS train shall be OPERABLE.

APPLICABILITY: MODE 4.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Required ECCS residual heat removal (RHR) subsystem inoperable.	A.1	Initiate action to restore required ECCS RHR subsystem to OPERABLE status.	Immediately
B. Required ECCS Safety Injection (SI) subsystem inoperable.	B.1	Restore required ECCS SI subsystem to OPERABLE status.	1 hour
C. Required Action and associated Completion Time of Condition B not met.	C.1	Be in MODE 5.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	-------------------NOTE------------------- An RHR train may be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned to the ECCS mode of operation. -- SR 3.5.2.4 is applicable for all equipment required to be OPERABLE.	In accordance with applicable SR

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.4 Refueling Water Storage Tank (RWST)

LCO 3.5.4 The RWST shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RWST boron concentration not within limits.	A.1 Restore RWST to OPERABLE status.	8 hours
B. RWST water volume not within limits.	B.1 Restore RWST to OPERABLE status.	1 hour
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.4.1	Verify RWST borated water volume is ≥ 300,000 gallons (88%).	7 days
SR 3.5.4.2	Verify RWST boron concentration is ≥ 2300 ppm and ≤ 2600 ppm.	7 days

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Accumulators

BASES

BACKGROUND

The functions of the ECCS accumulators are to supply water to the reactor vessel during the blowdown phase of a large break loss of coolant accident (LOCA), to provide inventory to help accomplish the refill phase that follows thereafter, and to provide Reactor Coolant System (RCS) makeup for a small break LOCA.

The blowdown phase of a large break LOCA is the initial period of the transient during which the RCS departs from equilibrium conditions, and heat from fission product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. The reactor coolant inventory is vacating the core during this phase through steam flashing and ejection out through the break. The blowdown phase of the transient ends when the RCS pressure falls to a value approaching that of the containment atmosphere.

In the refill phase of a LOCA, which immediately follows the blowdown phase, the core is essentially in adiabatic heatup. The balance of accumulator inventory is available to reflood the core and help fill voids in the lower plenum and reactor vessel downcomer so as to establish a recovery level at the bottom of the core.

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. The accumulators are passive components, since no operator or control actions are required in order for them to perform their function. Internal accumulator tank pressure is sufficient to discharge the accumulator contents to the RCS, if RCS pressure decreases below the accumulator pressure.

(continued)

BASES

BACKGROUND (continued)

Each accumulator is piped into an RCS cold leg via an accumulator line and is isolated from the RCS by a motor operated isolation valve and two check valves in series. The motor operated isolation valves (841 and 865) are maintained open with AC power removed under administrative control when pressurizer pressure is > 1600 psig. This feature ensures that the valves meet the single failure criterion of manually-controlled electrically operated valves per Branch Technical Position (BTP) ICSB-18 (Ref. 1). This is also discussed in References 2 and 3.

The accumulator size, water volume, and nitrogen cover pressure are selected so that one of the two accumulators is sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that one accumulator is adequate for this function is consistent with the LOCA assumption that the entire contents of one accumulator will be lost via the RCS pipe break during the blowdown phase of the LOCA.

APPLICABLE SAFETY ANALYSES

The accumulators are assumed OPERABLE in both the large and small break LOCA analyses at full power (Ref. 4). These are the Design Basis Accidents (DBAs) that establish the acceptance limits for the accumulators. Reference to the analyses for these DBAs is used to assess changes in the accumulators as they relate to the acceptance limits.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of ECCS flow. In the early stages of a large break LOCA, with or without a loss of offsite power, the accumulators provide the sole source of makeup water to the RCS. The assumption of loss of offsite power is required by regulations and conservatively imposes a delay wherein the ECCS pumps cannot deliver flow until the emergency diesel generators start, come to rated speed, and go through their timed loading sequence. In cold leg break scenarios, the entire contents of one accumulator are assumed to be lost through the break.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting large break LOCA is a double ended guillotine break at the discharge of the reactor coolant pump. During this event, the accumulators discharge to the RCS as soon as RCS pressure decreases to below accumulator pressure. As a conservative estimate, no credit is taken for ECCS pump flow until an effective delay has elapsed. This delay accounts for SI signal generation, the diesels starting, and the pumps being loaded and delivering full flow. During this time, the accumulators are analyzed as providing the sole source of emergency core cooling. No operator action is assumed during the blowdown stage of a large break LOCA.

The worst case small break LOCA analyses also assume a time delay before pumped flow reaches the core. For the larger range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated solely by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and safety injection pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the safety injection pumps become solely responsible for terminating the temperature increase.

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 (Ref. 5) will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react; and

d. Core is maintained in a coolable geometry.

Since the accumulators discharge during the blowdown phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

For both the large and small break LOCA analyses, a nominal contained accumulator water volume is used. The contained water volume is the same as the deliverable volume for the accumulators, since the accumulators are emptied, once discharged. For small breaks, an increase in water volume is a peak clad temperature penalty due to the reduced gas volume. A peak clad temperature penalty is an assumed increase in the calculated peak clad temperature due to a change in an input parameter. For large breaks, an increase in water volume can be either a peak clad temperature penalty or benefit, depending on downcomer filling and subsequent spill through the break during the core reflooding portion of the transient. The analysis uses a nominal accumulator volume and includes the line water volume from the accumulator to the check valve due to these competing effects.

The minimum boron concentration setpoint is used in the post LOCA boron concentration calculation. The calculation is performed to assure reactor subcriticality in a post LOCA environment. Of particular interest is the large break LOCA, since no credit is taken for control rod assembly insertion. A reduction in the accumulator minimum boron concentration would produce a subsequent reduction in the available containment sump concentration for post LOCA shutdown and an increase in the maximum sump pH. The maximum boron concentration is used in determining the time frame in which boron precipitation is addressed post LOCA. The maximum boron concentration limit is based on the coldest expected temperature of the accumulator water volume and on chemical effects resulting from operation of the ECCS and the Containment Spray (CS) System. The maximum value of 2600 ppm would not create the potential for boron precipitation in the accumulator assuming a containment temperature of 60°F (Ref. 6). Analyses performed in response to 10 CFR 50.49 (Ref. 7) assumed a chemical spray solution of 2000 to 3000 ppm boron concentration (Ref. 6). The chemical spray solution impacts sump pH and the resulting effect of chloride and caustic stress corrosion on mechanical systems and components. The sump pH also affects the rate of hydrogen generation within containment due to the interaction of CS and sump fluid with aluminum components.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The large and small break LOCA analyses are performed at the minimum nitrogen cover pressure, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak clad temperature benefit. The maximum nitrogen cover pressure limit prevents accumulator relief valve actuation at 800 psig, and ultimately preserves accumulator integrity.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. 8 and 9).

The accumulators satisfy Criterion 3 of the NRC Policy Statement.

LCO

The LCO establishes the minimum conditions required to ensure that the accumulators are available to accomplish their core cooling safety function following a LOCA. Two accumulators are required to ensure that 100% of the contents of one accumulator will reach the core during a LOCA. This is consistent with the assumption that the contents of one accumulator spill through the break. If less than one accumulator is injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 5) could be violated.

For an accumulator to be considered OPERABLE, the motor-operated isolation valve must be fully open, power removed above 1600 psig, and the limits established in the SRs for contained volume, boron concentration, and nitrogen cover pressure must be met.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure > 1600 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

(continued)

BASES

APPLICABILITY (continued)

This LCO is only applicable at pressures > 1600 psig. At pressures ≤ 1600 psig, the rate of RCS blowdown is such that the ECCS pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 (Ref. 5) limit of 2200°F.

In MODE 3, with RCS pressure ≤ 1600 psig, and in MODES 4, 5, and 6, the accumulator motor operated isolation valves are closed to isolate the accumulators from the RCS. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this Condition, the ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood since the accumulator water volume is very small when compared to RCS and RWST inventory. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analysis techniques demonstrate that the accumulators are not expected to discharge following a large steam line break. Even if they do discharge, their impact is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits.

(continued)

BASES

ACTIONS (continued)

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 1 hour. In this Condition, the required contents of one accumulator cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 1 hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions.

C.1 and C.2

If the accumulator cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and pressurizer pressure reduced to ≤ 1600 psig within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

If both accumulators are inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator motor-operated isolation valve shall be verified to be fully open every 12 hours. Use of control board indication for valve position is an acceptable verification. This verification ensures that the accumulators are available for injection and ensures timely discovery if a valve should be less than fully open. If an isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change with power removed, a closed valve could result in not meeting accident analyses assumptions. This Frequency is considered reasonable in view of other administrative controls that ensure a mispositioned isolation valve is unlikely.

SR 3.5.1.2 and SR 3.5.1.3

The borated water volume and nitrogen cover pressure shall be verified every 12 hours for each accumulator. This Frequency is sufficient to ensure adequate injection during a LOCA. Because of the static design of the accumulator, a 12 hour Frequency usually allows the operator to identify changes before limits are reached. Main control board alarms are also available for these accumulator parameters. Operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

SR 3.5.1.4

The boron concentration shall be verified to be within required limits for each accumulator every 31 days on a STAGGERED TEST Frequency since the static design of the accumulators limits the ways in which the concentration can be changed. The 31 day STAGGERED TEST Frequency is adequate to identify changes that could occur from mechanisms such as stratification or inleakage.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.5

Verification every 31 days that power is removed from each accumulator isolation valve operator when the pressurizer pressure is > 1600 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, no accumulators would be available for injection if the LOCA were to occur in the cold leg containing the only OPERABLE accumulator. Since power is removed under administrative control and valve position is verified every 12 hours, the 31 day Frequency will provide adequate assurance that power is removed.

REFERENCES

1. Branch Technical Position (BTP) ICSB-18 "Application of the Single Failure Criterion to Manually-Controlled Electrically Operated Valves."
2. Letter from D. M. Crutchfield, NRC, to J. E. Maier, RG&E, Subject: "SEP Topics VI-7.F, VII-3, VII-6, and VIII-2," dated June 24, 1981.
3. Letter from R. A. Purple, NRC, to L. D. White, RG&E, Subject: "Issuance of Amendment 7 to Provisional Operating License No. DPR-18," dated May 14, 1975.
4. UFSAR, Section 6.3.
5. 10 CFR 50.46.
6. UFSAR, Section 3.11.
7. 10 CFR 50.49.
8. UFSAR, Section 6.2.
9. UFSAR, Section 15.6.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS—MODES 1, 2, and 3

BASES

BACKGROUND

The function of the ECCS is to provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents:

a. Loss of coolant accident (LOCA) and coolant leakage greater than the capability of the normal charging system;

b. Rod ejection accident;

c. Loss of secondary coolant accident, including uncontrolled steam release or loss of feedwater; and

d. Steam generator tube rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to significant power.

There are two phases of ECCS operation: injection and recirculation. In the injection phase, water is taken from the refueling water storage tank (RWST) and injected into the Reactor Coolant System (RCS) through the cold legs and reactor vessel upper plenum. When sufficient water is removed from the RWST to ensure that enough boron has been added to maintain the reactor subcritical and the containment sump has enough water to supply the required net positive suction head to the ECCS pumps, suction is switched to Containment Sump B for recirculation. After approximately 20 hours, simultaneous ECCS injection is used to reduce the potential for boiling in the top of the core and any resulting boron precipitation.

The ECCS consists of two separate subsystems: safety injection (SI) and residual heat removal (RHR). Each subsystem consists of two redundant, 100% capacity trains. The ECCS accumulators and the RWST are also part of the ECCS, but are not considered part of an ECCS flow path as described by this LCO.

(continued)

BASES

BACKGROUND (continued)

The ECCS flow paths which comprise the redundant trains consist of piping, valves, heat exchangers, and pumps such that water from the RWST can be injected into the RCS following the accidents described in this LCO. The major components of each subsystem are the RHR pumps, heat exchangers, and the SI pumps. The RHR subsystem consists of two 100% capacity trains that are interconnected and redundant such that either train is capable of supplying 100% of the flow required to mitigate the accident consequences. The SI subsystem consists of three redundant, 50% capacity pumps which supply two RCS cold leg injection lines. Each injection line is capable of providing 100% of the flow required to mitigate the consequences of an accident. These interconnecting and redundant subsystem designs provide the operators with the ability to utilize components from opposite trains to achieve the required 100% flow to the core.

During the injection phase of LOCA recovery, suction headers supply water from the RWST to the ECCS pumps. A common supply header is used from the RWST to the safety injection (SI) and containment spray (CS) System pumps. This common supply header is provided with two in-series motor-operated isolation valves (896A and 896B) that receive power from separate sources for single failure considerations. These isolation valves are maintained open with DC control power removed via a key switch located in the control room. The removal of DC control power eliminates the most likely causes for spurious valve actuation while maintaining the capability to manually close the valves from the control room during the recirculation phase of the accident (Ref. 1). The SI pump supply header also contains two parallel motor-operated isolation valves (825A and 825B) which are maintained open by removing AC power. The removal of AC power to these isolation valves is an acceptable design against single failures that could result in undesirable component actuation (Ref. 2).

(continued)

BASES

BACKGROUND (continued)

A separate supply header is used for the residual heat removal (RHR) pumps. This supply header is provided with a check valve (854) and motor operated isolation valve (856) which is maintained open with DC control power removed via a key switch located in the control room. The removal of DC control power eliminates the most likely causes for spurious valve actuation while maintaining the capability to manually close the valve from the control room during the recirculation phase of the accident (Ref. 3).

The three SI pumps feed two RCS cold leg injection lines. SI Pumps A and B each feeds one of the two injection lines while SI Pump C can feed both injection lines. The discharge of SI Pump C is controlled through use of two normally open parallel motor operated isolation valves (871A and 871B). These isolation valves are designed to close based on the operating status of SI Pumps A and B to ensure that SI Pump C provides the necessary flow through the RCS cold leg injection line containing the failed pump.

The discharges of the two RHR pumps and heat exchangers feed a common injection line which penetrates containment. This line then divides into two redundant core deluge flow paths each containing a normally closed motor operated isolation valve (852A and 852B) and check valve (853A and 853B) which provide injection into the reactor vessel upper plenum.

For LOCAs that are too small to depressurize the RCS below the shutoff head of the SI pumps, the steam generators provide core cooling until the RCS pressure decreases below the SI pump shutoff head.

During the recirculation phase of LOCA recovery, RHR pump suction is manually transferred to Containment Sump B (Refs. 4 and 5). This transfer is accomplished by stopping the RHR pumps, isolating RHR from the RWST by closing motor operated isolation valve 856, opening the Containment Sump B motor operated isolation valves to RHR (850A and 850B) and then starting the RHR pumps. The SI and CS pumps are then stopped and the RWST isolated by closing motor operated isolation valve 896A and 896B for the SI and CS pump common supply header and closing motor operated isolation valve 897 or 898 for the SI pumps recirculation line.

(continued)

BASES

BACKGROUND (continued)

The RHR pumps then supply the SI pumps if the RCS pressure remains above the RHR pump shutoff head as correlated through core exit temperature, containment pressure, and reactor vessel level indications (Ref. 6). The RHR pumps can also provide suction to the CS pumps for containment pressure control. This high-head recirculation path is provided through RHR motor operated isolation valves 857A, 857B, and 857C. These isolation valves are interlocked with valves 896A, 896B, 897, and 898. This interlock prevents opening of the RHR high-head recirculation isolation valves unless either 896A or 896B are closed and either 897 or 898 are closed. If RCS pressure is such that RHR provides adequate core and containment cooling, the SI and CS pumps remain in pull-stop. During recirculation, flow is discharged through the same paths as the injection phase. After approximately 20 hours, simultaneous injection by the SI and RHR pumps is used to prevent boron precipitation (Ref. 7). This consists of providing SI through the RCS cold legs and into the lower plenum while providing RHR through the core deluge valves into the upper plenum.

The two redundant flow paths from Containment Sump B to the RHR pumps also contain a motor operated isolation valve located within the sump (851A and 851B). These isolation valves are maintained open with power removed to improve the reliability of switchover to the recirculation phase. The operators for isolation valves 851A and 851B are also not qualified for containment post accident conditions. The removal of AC power to these isolation valves is an acceptable design against single failures that could result in an undesirable actuation (Ref. 2).

The SI subsystem of the ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a steam line break (SLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

During low temperature conditions in the RCS, limitations are placed on the maximum number of ECCS pumps that may be OPERABLE. Refer to the Bases for LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," for the basis of these requirements.

(continued)

BASES

BACKGROUND (continued)

The ECCS subsystems are actuated upon receipt of an SI signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start immediately in the programmed sequence. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the emergency diesel generators (EDGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive accumulators and the RWST covered in LCO 3.5.1, "Accumulators," and LCO 3.5.4, "Refueling Water Storage Tank (RWST)," provide the cooling water necessary to meet AIF-GDC 44 (Ref. 8).

APPLICABLE SAFETY ANALYSIS

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 9), will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. Core is maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

The LCO also limits the potential for a post trip return to power following an SLB event and helps ensure that containment temperature limits are met post accident.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

Both ECCS subsystems are taken credit for in a large break LOCA event at full power (Refs. 6 and 10). This event establishes the requirement for runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The SI pumps are credited in a small break LOCA event. This event establishes the flow and discharge head at the design point for the pumps. The SGTR and SLB events also credit the SI pumps. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. A large break LOCA event, with loss of offsite power and a single failure disabling one RHR pump (both EDG trains are assumed to operate due to requirements for modeling full active containment heat removal system operation); and

b. A small break LOCA event, with a loss of offsite power and a single failure disabling one ECCS train.

During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod insertion for small breaks. Following depressurization, emergency cooling water is injected by the SI pumps into the cold legs, flows into the downcomer, fills the lower plenum, and refloods the core. The RHR pumps inject directly into the core barrel by upper plenum injection.

The effects on containment mass and energy releases are accounted for in appropriate analyses (Refs. 10 and 11). The LCO ensures that an ECCS train will deliver sufficient water to match boiloff rates quickly enough to minimize the consequences of the core being uncovered following a large LOCA. It also ensures that the SI pumps will deliver sufficient water and boron during a small LOCA to maintain core subcriticality. For smaller LOCAs, the SI pumps deliver sufficient fluid to maintain RCS inventory. For a small break LOCA, the steam generators continue to serve as the heat sink, providing part of the required core cooling.

The ECCS trains satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

In MODES 1, 2, and 3, two independent (and redundant) ECCS trains are required to ensure that sufficient ECCS flow is available, assuming a single failure affecting either train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents.

In MODES 1, 2, and 3, an ECCS train consists of an SI subsystem and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an SI signal and transferring suction to Containment Sump B. This includes securing the motor operated isolation valves as specified in SR 3.5.2.1 in position by removing the power sources as listed below.

EIN	Position	Secured in Position By
825A	Open	Removal of AC Power
825B	Open	Removal of AC Power
826A	Closed	Removal of AC power
826B	Closed	Removal of AC Power
826C	Closed	Removal of AC Power
826D	Closed	Removal of AC Power
851A	Open	Removal of AC power
851B	Open	Removal of AC Power
856	Open	Removal of DC Control Power
878A	Closed	Removal of AC Power
878B	Open	Removal of AC Power
878C	Closed	Removal of AC Power
878D	Open	Removal of AC Power
896A	Open	Removal of DC Control Power
896B	Open	Removal of DC Control Power

The major components of an ECCS train consists of an RHR pump and heat exchanger taking suction from the RWST (and eventually Containment Sump B), and capable of injecting through one of the two isolation valves to the reactor vessel upper plenum and one of the two lines which provide high-head recirculation to the SI and CS pumps.

(continued)

BASES

LCO (continued)

Also included within the ECCS train are two of three SI pumps capable of taking suction from the RWST and Containment Sump B (via RHR), and injecting through one of the two RCS cold leg injection lines. In the case where SI Pump C is inoperable, both RCS cold leg injection lines must be OPERABLE to provide 100% of the ECCS flow equivalent to a single train of SI due to the location of check valves 870A and 870B.

The flow path for each train must maintain its designed independence to ensure that no single failure can disable both ECCS trains.

APPLICABILITY

In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. The SI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

In MODE 4, the ECCS requirements are as described in LCO 3.5.3, "ECCS—MODE 4."

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation—Water Level ≥ 23 Ft," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—Water Level < 23 Ft."

As indicated in Note 1, the flow path may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. The flow path is readily restorable from the control room or by field test personnel. The note also allows an SI isolation MOV to be powered for up to 12 hours for the performance of this testing.

(continued)

BASES

APPLICABILITY (continued)

As indicated in Note 2, operation in MODE 3 with ECCS trains declared inoperable pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," may be necessary since the LTOP arming temperature is near the MODE 3 boundary temperature of 350°F. LCO 3.4.12 requires that certain pumps be rendered inoperable at and below the LTOP arming temperature. When this temperature is near the MODE 3 boundary temperature, time is needed to restore the inoperable pumps to OPERABLE status.

In MODES 4, 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Mode 4 core cooling requirements are addressed by LCO 3.4.6, "RCS Loops - Mode 4," and LCO 3.5.3, "ECCS - MODE 4." Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation—Water Level ≥ 23 Ft," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—Water Level < 23 Ft."

ACTIONS

A.1

With one train inoperable and at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 12) and is a reasonable time for repair of many ECCS components.

An ECCS train is inoperable if it is not capable of delivering 100% design flow to the RCS. Individual components are inoperable if they are not capable of performing their design function or necessary supporting systems are not available.

(continued)

BASES

ACTIONS

A.1 (continued)

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one active component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the ECCS. The intent of this Condition is to maintain a combination of equipment such that 100% of the ECCS flow equivalent to a single OPERABLE ECCS train remains available. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

In the case where SI Pump C is inoperable, both RCS cold leg injection lines must be OPERABLE to provide 100% of the ECCS flow equivalent to a single train of SI due to the location of check valves 870A and 870B.

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 2) has shown that the impact of having one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

B.1 and B.2

If the inoperable train cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

C.1

If both trains of ECCS are inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be immediately entered. With one or more component(s) inoperable such that 100% of the flow equivalent to a single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be immediately entered.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Use of control board indication for valve position is an acceptable verification. Misalignment of these valves could render both ECCS trains inoperable. The listed valves are secured in position by removal of AC power or key locking the DC control power. These valves are operated under administrative controls such that any changes with respect to the position of the valve breakers or key locks is unlikely. The verification of the valve breakers and key locks is performed by SR 3.5.2.3. Mispositioning of these valves can disable the function of both ECCS trains and invalidate the accident analyses. A 12 hour Frequency is considered reasonable in view of other administrative controls that ensure a mispositioned valve is unlikely.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve will automatically reposition within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day Frequency is appropriate because the valves are operated under administrative control, and an improper valve position in most cases, would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.2.3

Verification every 31 days that AC or DC power is removed, as appropriate, for each valve specified in SR 3.5.2.1 ensures that an active failure could not result in an undetected misposition of a valve which affects both trains of ECCS. If this were to occur, no ECCS injection or recirculation would be available. Since power is removed under administrative control and valve position is verified every 12 hours, the 31 day Frequency will provide adequate assurance that power is removed.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.4

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by Section XI of the ASME Code. This type of testing may be accomplished by measuring the pump developed head at a single point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. SRs are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code. Section XI of the ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.5 and SR 3.5.2.6

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SI signal and that each ECCS pump starts on receipt of an actual or simulated SI signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for unplanned plant transients if the Surveillances were performed with the reactor at power. The 24 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the Inservice Testing Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.7

Periodic inspections of the containment sump suction inlet to the RHR System ensure that it is unrestricted and stays in proper operating condition. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, on the need to have access to the location, and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. This Frequency has been found to be sufficient to detect abnormal degradation and is confirmed by operating experience.

REFERENCES

1. Letter from R. A. Purple, NRC, to L. D. White, RG&E, Subject: "Issuance of Amendment 7 to Provisional Operating License No. DPR-18," dated May 14, 1975.

2. Branch Technical Position (BTP) ICSB-18, "Application of the Single Failure Criterion to Manually-Controlled Electrically Operated Valves."

3. Letter from A. R. Johnson, NRC, to R. C. Mecredy, RG&E, Subject: "Issuance of Amendment No. 42 to Facility Operating License No. DPR-18, R. E. Ginna Nuclear Power Plant (TAC No. 79829)," dated June 3, 1991.

4. Letter from D. M. Crutchfield, NRC, to J. E. Maier, RG&E, Subject: "SEP Topic VI-7.B: ESF Switchover from Injection to Recirculation Mode, Automatic ECCS Realignment, Ginna," dated December 31, 1981.

5. NUREG-0821.

6. UFSAR, Section 6.3.

7. Letter from D. M. Crutchfield, NRC, to J. E. Maier, RG&E, Subject: "SEP Topic IX-4, Boron Addition System, R. E. Ginna," dated August 26, 1981.

8. Atomic Industrial Forum (AIF) GDC 44, Issued for comment July 10, 1967.

(continued)

BASES

REFERENCES (continued)

9. 10 CFR 50.46.

10. UFSAR, Section 15.6.

11. UFSAR, Section 6.2.

12. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS — MODE 4

BASES

BACKGROUND

The Background section for Bases 3.5.2, "ECCS — MODES 1, 2, and 3," is applicable to these Bases, with the following modifications.

In MODE 4, the required ECCS train consists of two separate subsystems: safety injection (SI) and residual heat removal (RHR).

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the refueling water storage tank (RWST) can be injected into the Reactor Coolant System (RCS). The RHR subsystem must also be capable of taking suction from containment Sump B to provide recirculation.

APPLICABLE SAFETY ANALYSES

There are no Applicable Safety Analyses which apply to the ECCS in MODE 4 due to the stable conditions associated with operation in MODE 4 and the reduced probability of occurrence of a Design Basis Accident. Therefore, the ECCS operational requirements are reduced in MODE 4. It is understood in these reductions that certain automatic SI actuations are not available. In this MODE, sufficient time is expected for manual actuation of the required ECCS to mitigate the consequences of a DBA. This time is also required since the RHR System may be aligned to provide normal shutdown cooling while the SI System may be isolated from the RCS due to low temperature overpressure protection (LTOP) concerns.

Therefore, only one train of ECCS is required for MODE 4. This requirement dictates that single failures are not considered for this LCO due to the time available for operators to respond to an accident. The ECCS trains satisfy Criterion 4 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

In MODE 4, one of the two independent (and redundant) ECCS trains is required to be OPERABLE to ensure that sufficient ECCS flow is available to the core following an accident.

In MODE 4, an ECCS train consists of an SI subsystem and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST and transferring suction to the containment sump. The major components of an ECCS train during MODE 4 consists of an RHR pump and heat exchanger, capable of taking suction from the RWST (and eventually Containment Sump B), and able to inject through one of two isolation valves to the reactor vessel upper plenum. Also included within the ECCS train are one of three SI pumps capable of taking suction from the RWST and injecting through one of two RCS cold leg injection lines. The high-head recirculation flow path from RHR to the SI pumps is not required in the MODE 4 since there is no accident scenario which prevents depressurization to the RHR pump shutoff head prior to depletion of the RWST.

Based on the expected time available to respond to accident conditions during MODE 4, and the configuration of the RHR and SI trains, ECCS components are OPERABLE if they are capable of being reconfigured to the injection mode (remotely or locally) within 10 minutes. This includes taking credit for an RHR pump and heat exchanger as being OPERABLE if they are being used for shutdown cooling purposes. LCO 3.4.12, "LTOP System" contains additional requirements for the configuration of the SI system.

APPLICABILITY

In MODES 1, 2, and 3, the OPERABILITY requirements for ECCS are covered by LCO 3.5.2.

In MODE 4 with RCS temperature below 350°F, one OPERABLE ECCS train is acceptable without single failure consideration, on the basis of the stable reactivity of the reactor and the limited core cooling requirements.

(continued)

BASES

APPLICABILITY (continued)

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation—Water Level ≥ 23 Ft," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—Water Level < 23 Ft."

ACTIONS

A.1

With no ECCS RHR subsystem OPERABLE, the plant is not prepared to respond to a loss of coolant accident or to continue a cooldown using the RHR pumps and heat exchangers. The Completion Time of immediately to initiate actions that would restore at least one ECCS RHR subsystem to OPERABLE status ensures that prompt action is taken to restore the required cooling capacity. Normally, in MODE 4, reactor decay heat is removed from the RCS by an RHR loop. If no RHR loop is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generators. The alternate means of heat removal must continue until the inoperable RHR loop components can be restored to operation so that decay heat removal is continuous.

With both RHR pumps and heat exchangers inoperable, it would be unwise to require the plant to go to MODE 5, where the only available heat removal system is the RHR subsystem. Therefore, the appropriate action is to initiate measures to restore one ECCS RHR subsystem and to continue the actions until the subsystem is restored to OPERABLE status.

(continued)

BASES

ACTIONS (continued)

B.1

With no ECCS SI subsystem OPERABLE, due to the inoperability of the SI pump or flow path from the RWST, the plant is not prepared to provide high pressure response to an accident requiring SI. The 1 hour Completion Time to restore at least one SI subsystem to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the plant in MODE 5, where an ECCS train is not required.

C.1

When the Required Actions of Condition B cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Twenty-four hours is a reasonable time, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems or operators.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance description from Bases 3.5.2 apply. This SR is modified by a Note that allows an RHR train to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the ECCS mode of operation and not otherwise inoperable. This allows operation in the RHR mode during MODE 4, if necessary.

REFERENCES

None.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Refueling Water Storage Tank (RWST)

BASES

BACKGROUND

The RWST supplies borated water to both trains of the ECCS and the Containment Spray (CS) System during the injection phase of a loss of coolant accident (LOCA) recovery. A common supply header is used from the RWST to the safety injection (SI) and CS pumps. A separate supply header is used for the residual heat removal (RHR) pumps. Isolation valves and check valves are used to isolate the RWST from the ECCS and CS System prior to transferring to the recirculation mode. The recirculation mode is entered when pump suction is transferred to the containment sump based on RWST level. Use of a single RWST to supply both trains of the ECCS and CS System is acceptable since the RWST is a passive component, and passive failures are not required to be assumed to occur coincidentally with Design Basis Events.

The RWST is located in the Auxiliary Building which is normally maintained between 50°F and 104°F (Ref. 1). These moderate temperatures provide adequate margin with respect to potential freezing or overheating of the borated water contained in the RWST.

During normal operation in MODES 1, 2, and 3, the safety injection (SI), RHR, and CS pumps are aligned to take suction from the RWST.

The ECCS and CS pumps are provided with recirculation lines that ensure each pump can maintain minimum flow requirements when operating at or near shutoff head conditions. The recirculation lines for the RHR and CS pumps are directed from the discharge of the pumps to the pump suction. The recirculation lines for the SI pumps are directed back to the RWST.

(continued)

BASES

BACKGROUND (continued)

When the suction for the ECCS and CS pumps is transferred to the containment sump, the RWST and SI pump recirculation flow paths must be isolated to prevent a release of the containment sump contents to the RWST, which could result in a release of contaminants to the Auxiliary Building and the eventual loss of suction head for the ECCS pumps.

This LCO ensures that:

a. The RWST contains sufficient borated water to support the ECCS and CS system during the injection phase;

b. Sufficient water volume exists in the containment sump to support continued operation of the ECCS and CS pumps at the time of transfer to the recirculation mode of cooling; and

c. The reactor remains subcritical following a LOCA.

Insufficient water in the RWST could result in inadequate NPSH for the RHR pumps when the transfer to the recirculation mode occurs. Improper boron concentrations could result in a reduction of SDM or excessive boric acid precipitation in the core following the LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment.

APPLICABLE SAFETY ANALYSES

During accident conditions, the RWST provides a source of borated water to the ECCS and CS pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Ref. 3). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of LCO 3.5.2, "ECCS—MODES 1, 2, and 3"; LCO 3.5.3, "ECCS—MODE 4"; and LCO 3.6.6, "Containment Spray (CS), Containment Recirculation Fan Cooler (CRFC), NaOH, and Containment Post-Accident Charcoal Systems." These analyses are used to assess changes to the RWST in order to evaluate their effects in relation to the acceptance limits in the analyses.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The RWST must also meet volume, boron concentration, and temperature requirements for non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the volume required for Reactor Coolant System (RCS) makeup is a small fraction of the available RCS volume. The deliverable volume limit is set by the LOCA and containment analyses. For the RWST, the deliverable volume is selected such that switchover to recirculation does not occur until sufficient water has been pumped into containment to provide necessary NPSH for the RHR pumps. The minimum boron concentration is an explicit assumption in the steam line break (SLB) analysis to ensure the required shutdown capability. The maximum boron concentration is an explicit assumption in the evaluation of chemical effects resulting from the operation of the CS System.

For a large break LOCA analysis, the minimum water volume limit of 300,000 gallons and the lower boron concentration limit are used to compute the post LOCA sump boron concentration necessary to assure subcriticality. The large break LOCA is the limiting case since the safety analysis assumes that all control rods are out of the core.

The upper limit on boron concentration is used to determine the time frame in which boron precipitation is addressed post LOCA. The maximum boron concentration limit is based on the coldest expected temperature of the RWST water volume and on chemical effects resulting from operation of the ECCS and the CS System. A value ≤ 2600 ppm would not create the potential for boron precipitation in the RWST assuming an Auxiliary Building temperature of 50°F (Ref. 1). Analyses performed in response to 10 CFR 50.49 (Ref. 2) assumed a chemical spray solution of 2000 to 3000 ppm boron concentration (Ref. 1). The chemical spray solution impacts sump pH and the resulting effect of chloride and caustic stress corrosion on mechanical systems and components. The sump pH also affects the rate of hydrogen generation within containment due to the interaction of CS and sump fluid with aluminum components.

The RWST satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

The RWST ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and to ensure adequate level in the containment sump to support ECCS and CS pump operation in the recirculation mode.

To be considered OPERABLE, the RWST must meet the water volume and boron concentration limits established in the SRs.

APPLICABILITY

In MODES 1, 2, 3, and 4, RWST OPERABILITY requirements are dictated by ECCS and CS System OPERABILITY requirements. Since both the ECCS and the CS System must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also be OPERABLE to support their operation. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops – MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation – Water Level ≥ 23 Ft," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Water Level < 23 Ft."

ACTIONS

A.1

With RWST boron concentration not within limits, it must be returned to within limits within 8 hours. Under these conditions neither the ECCS nor the CS System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE condition. The 8 hour limit to restore the RWST boron concentration to within limits was developed considering the time required to change the boron concentration and the fact that the contents of the tank are still available for injection.

(continued)

BASES

ACTIONS (continued)

B.1

With the RWST water volume not within limits, it must be restored to OPERABLE status within 1 hour. In this Condition, neither the ECCS nor the CS System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains.

C.1 and C.2

If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST water volume should be verified every 7 days to be above the required minimum level in order to ensure that a sufficient initial supply is available for injection and to support continued ECCS and CS System pump operation on recirculation. Since the RWST volume is normally stable and the RWST is located in the Auxiliary Building which provides sufficient leak detection capability, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.4.2

The boron concentration of the RWST should be verified every 7 days to be within the required limits. This SR ensures that the reactor will remain subcritical following a LOCA. Further, it assures that the resulting sump pH will be maintained in an acceptable range so that boron precipitation in the core will not occur and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. Since the RWST volume is normally stable, a 7 day sampling Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.

REFERENCES

1. UFSAR, Section 3.11.
2. 10 CFR 50.49.
3. UFSAR, Section 6.3 and Chapter 15.

3.6 CONTAINMENT SYSTEMS

3.6.1 Containment

LCO 3.6.1 Containment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment inoperable.	A.1 Restore containment to OPERABLE status.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1	-------------------NOTE------------------- SR 3.0.2 is not applicable. -- Perform required visual examinations and leakage rate testing except for containment air lock and containment mini-purge valve testing, in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program
SR 3.6.1.2	Verify containment structural integrity in accordance with the Containment Tendon Surveillance Program.	In accordance with the Containment Tendon Surveillance Program

3.6 CONTAINMENT SYSTEMS

3.6.2 Containment Air Locks

LCO 3.6.2 Two containment air locks shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-----------------------------------NOTES-----------------------------------

1. Entry and exit is permissible to perform repairs on the affected air lock components.
2. Separate Condition entry is allowed for each air lock.
3. Enter applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when air lock leakage results in exceeding the overall containment leakage rate acceptance criteria.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment air locks with one containment air lock door inoperable.	------------NOTES------------ 1. Required Actions A.1, A.2, and A.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit is permissible for 7 days under administrative controls if both air locks are inoperable. -----------------------------	

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.1	Verify the OPERABLE door is closed in the affected air lock.	1 hour
	AND		
	A.2	Lock the OPERABLE door closed in the affected air lock.	24 hours
	AND		
	A.3	--------NOTE--------- Air lock doors in high radiation areas may be verified locked closed by administrative means. ---------------------	
		Verify the OPERABLE door is locked closed in the affected air lock.	Once per 31 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more containment air locks with containment air lock interlock mechanism inoperable.	------------NOTES------------ 1. Required Actions B.1, B.2, and B.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit of containment is permissible under the control of a dedicated individual. ----------------------------	
	B.1 Verify an OPERABLE door is closed in the affected air lock.	1 hour
	<u>AND</u>	
	B.2 Lock an OPERABLE door closed in the affected air lock.	24 hours
	<u>AND</u>	
	B.3 --------NOTE--------- Air lock doors in high radiation areas may be verified locked closed by administrative means. ---------------------	
	Verify an OPERABLE door is locked closed in the affected air lock.	Once per 31 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more containment air locks inoperable for reasons other than Condition A or B.	C.1	Initiate action to evaluate overall containment leakage rate per LCO 3.6.1.	Immediately
	AND		
	C.2	Verify a door is closed in the affected air lock.	1 hour
	AND		
	C.3	Restore air lock to OPERABLE status.	24 hours
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1	-------------------NOTES------------------- 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1. --- Perform required air lock leakage rate testing in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program
SR 3.6.2.2	Verify only one door in each air lock can be opened at a time.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.3 Containment Isolation Boundaries

LCO 3.6.3 Each containment isolation boundary shall be OPERABLE.

-------------------------NOTES-------------------------

1. Not applicable to the main steam safety valves in MODES 1, 2, and 3.
2. Not applicable to the main steam isolation valves (MSIVs) in MODE 1, and in MODES 2 and 3 with the MSIVs open or not deactivated.
3. Not applicable to the atmospheric relief valves in MODES 1 and 2, and in MODE 3 with the Reactor Coolant System average temperature (T_{avg}) $\geq$ 500°F.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-------------------------NOTES-------------------------

1. Penetration flow path(s), except for Shutdown Purge System valve flow paths, may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each penetration flow path.
3. Enter applicable Conditions and Required Actions for systems made inoperable by containment isolation boundaries.
4. Enter applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when isolation boundary leakage results in exceeding the overall containment leakage rate acceptance criteria.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. ---------NOTE--------- Only applicable to penetration flow paths which do not use a closed system as a containment isolation boundary. --------------------- One or more penetration flow paths with one containment isolation boundary inoperable except for mini-purge valve leakage not within limit.	A.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	4 hours
	<u>AND</u>		
	A.2	--------NOTE--------- Isolation boundaries in high radiation areas may be verified by use of administrative means. --------------------- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation boundaries outside containment <u>AND</u> Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation boundaries inside containment

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. ---------NOTE--------- Only applicable to penetration flow paths which do not use a closed system as a containment isolation boundary. ---------------------- One or more penetration flow paths with two containment isolation boundaries inoperable except for mini-purge valve leakage not within limit.	B.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. ---------NOTE--------- Only applicable to penetration flow paths which use a closed system as a containment isolation boundary. ---------------------	C.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	72 hours
One or more penetration flow paths with one containment isolation boundary inoperable.	AND		
	C.2	--------NOTE--------- Isolation boundaries in high radiation areas may be verified by use of administrative means. --------------------	
		Verify the affected penetration flow path is isolated.	Once per 31 days for isolation boundaries outside containment AND Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation boundaries inside containment

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One or more mini-purge penetration flow paths with one valve not within leakage limits.	D.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	24 hours
	<u>AND</u>		
	D.2	--------NOTE--------- Isolation boundaries in high radiation areas may be verified by use of administrative means. --------------------	
		Verify the affected penetration flow path is isolated.	Once per 31 days for isolation boundaries outside containment <u>AND</u> Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation boundaries inside containment

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. One or more mini-purge penetration flow paths with two valves not within leakage limits.	E.1	Initiate action to evaluate overall containment leakage rate per LCO 3.6.1.	Immediately
	<u>AND</u>		
	E.2	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour
F. Required Action and associated Completion Time not met.	F.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	F.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1	Verify each mini-purge valve is closed, except when the penetration flowpath(s) are permitted to be open under administrative control.	31 days
SR 3.6.3.2	-------------------NOTES------------------ 1. Isolation boundaries in high radiation areas may be verified by use of administrative controls. 2. Not applicable to containment isolation boundaries which receive an automatic containment isolation signal. --- Verify each containment isolation boundary that is located outside containment and not locked, sealed, or otherwise secured in the required position is performing its containment isolation accident function except for containment isolation boundaries that are open under administrative controls.	92 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.3.3	-------------------NOTES------------------- 1. Isolation boundaries in high radiation areas may be verified by use of administrative means. 2. Not applicable to containment isolation boundaries which receive an automatic containment isolation signal. --- Verify each containment isolation boundary that is located inside containment and not locked, sealed, or otherwise secured in the required position is performing its containment isolation accident function, except for containment isolation boundaries that are open under administrative controls.	Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days
SR 3.6.3.4	Verify the isolation time of each automatic containment isolation valve is within limits.	In accordance with the Inservice Testing Program
SR 3.6.3.5	Perform required leakage rate testing of containment mini-purge valves with resilient seals in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Program.
SR 3.6.3.6	Verify each automatic containment isolation valve that is not locked, sealed, or otherwise secured in the required position actuates to the isolation position on an actual or simulated actuation signal.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.4 Containment Pressure

LCO 3.6.4 Containment pressure shall be ≥ -2.0 psig and ≤ 1.0 psig.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment pressure not within limits.	A.1 Restore containment pressure to within limits.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.4.1 Verify containment pressure is within limits.	12 hours

3.6 CONTAINMENT SYSTEMS

3.6.5 Containment Air Temperature

LCO 3.6.5 Containment average air temperature shall be ≤ 120°F.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment average air temperature not within limit.	A.1 Restore containment average air temperature to within limit.	24 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.5.1 Verify containment average air temperature is within limit.	12 hours

3.6 CONTAINMENT SYSTEMS

3.6.6 Containment Spray (CS), Containment Recirculation Fan Cooler (CRFC), NaOH, and Containment Post-Accident Charcoal Systems

LCO 3.6.6 Two CS trains, four CRFC units, two post-accident charcoal filter trains, and the NaOH system shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CS train inoperable.	A.1 Restore CS train to OPERABLE status.	72 hours
B. One post-accident charcoal filter train inoperable.	B.1 Restore post-accident charcoal filter to OPERABLE status.	7 days
C. Two post-accident charcoal filter trains inoperable.	C.1 Restore one post-accident charcoal filter train to OPERABLE status.	72 hours
D. NaOH system inoperable.	D.1 Restore NaOH System to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	E.2	Be in MODE 5.	84 hours
F. One or two CRFC units inoperable.	F.1	--------NOTE--------- Required Action F.1 only required if CRFC unit A or C is inoperable. ---------------------	
		Declare associated post-accident charcoal filter train inoperable.	Immediately
	<u>AND</u>		
	F.2	Restore CRFC unit(s) to OPERABLE status.	7 days
G. Required Action and associated Completion Time of Condition F not met.	G.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	G.2	Be in MODE 5.	36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. Two CS trains inoperable. OR NaOH System and one or both post-accident charcoal filter trains inoperable. OR Three or more CRFC units inoperable. OR One CS and two post-accident charcoal filter trains inoperable.	H.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.6.1	Perform SR 3.5.2.1 and SR 3.5.2.3 for valves 896A and 896B.	In accordance with applicable SRs.
SR 3.6.6.2	Verify each CS manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days
SR 3.6.6.3	Verify each NaOH System manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days
SR 3.6.6.4	Operate each CRFC unit for ≥ 15 minutes.	31 days
SR 3.6.6.5	Verify cooling water flow through each CRFC unit.	31 days
SR 3.6.6.6	Operate each post-accident charcoal filter train for ≥ 15 minutes.	31 days
SR 3.6.6.7	Verify each CS pump's developed head at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.6.8	Verify NaOH System solution volume is ≥ 4500 gal.	184 days
SR 3.6.6.9	Verify NaOH System tank NaOH solution concentration is ≥ 30% by weight.	184 days
SR 3.6.6.10	Perform required post-accident charcoal filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.6.6.11	Perform required CRFC unit testing in accordance with the VFTP.	In accordance with the VFTP
SR 3.6.6.12	Verify each automatic CS valve in the flow path that is not locked, sealed, or otherwise secured in position actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.6.6.13	Verify each CS pump starts automatically on an actual or simulated actuation signal.	24 months
SR 3.6.6.14	Verify each CRFC unit starts automatically on an actual or simulated actuation signal.	24 months
SR 3.6.6.15	Verify each post-accident charcoal filter train damper actuates on an actual or simulated actuation signal.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.6.16	Verify each automatic NaOH System valve in the flow path that is not locked, sealed, or otherwise secured in position actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.6.6.17	Verify spray additive flow through each eductor path.	5 years
SR 3.6.6.18	Verify each spray nozzle is unobstructed.	10 years

3.6 CONTAINMENT SYSTEMS

3.6.7 Hydrogen Recombiners

LCO 3.6.7 Two hydrogen recombiners shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One hydrogen recombiner inoperable.	A.1	--------NOTE--------- LCO 3.0.4 is not applicable. ---------------------	
		Restore hydrogen recombiner to OPERABLE status.	30 days
B. Two hydrogen recombiners inoperable.	B.1	Verify by administrative means that the hydrogen control function is maintained.	1 hour <u>AND</u> Once per 12 hours thereafter
	<u>AND</u>		
	B.2	Restore one hydrogen recombiner to OPERABLE status.	7 days
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.7.1	Perform a system functional check for each hydrogen recombiner.	24 months
SR 3.6.7.2	Perform CHANNEL CALIBRATION for each hydrogen recombiner actuation and control channel.	24 months

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment consists of the concrete containment structure, its steel liner, and the penetrations through this structure. The structure is designed to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA) in accordance with Atomic Industry Forum (AIF) GDC 10 and 49 (Ref. 1). Additionally, this structure provides shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment is a reinforced concrete structure with a cylindrical wall, a flat base mat, and a hemispherical dome roof. The inside surface of the containment is lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions. Each weld seam on the inside of the liner has a leak test channel welded over it to allow independent testing of the liner when the containment is open. The liner is also insulated with closed-cell polyvinyl foam covered with metal sheeting up to the containment spray ring headers. The function of the liner insulation is to limit the mean temperature rise of the liner to only 10°F at the time associated with maximum pressure following a DBA (Ref. 2).

The containment hemispherical dome is constructed of reinforced concrete designed for all DBA related moments, axial loads, and shear forces. The cylinder wall is prestressed vertically and reinforced circumferentially with mild steel deformed bars. The base mat is a reinforced concrete slab that is connected to the cylinder wall by use of a hinge design which prevents the transfer of imposed shear from the cylinder wall to the base mat. This hinge consists of elastomer bearing pads located between the bottom of the cylinder wall and the base mat, and high strength steel bars which connect the cylinder walls horizontally to the base mat (Ref. 2).

(continued)

BASES

BACKGROUND (continued)

The cylinder wall is connected to sandstone rock located beneath the containment by use of 160 post-tensioned rock anchors that are coupled with tendons located in the cylinder wall. This design ensures that the rock acts as an integral part of the containment structure.

The concrete containment structure is required for structural integrity of the containment under DBA conditions. The steel liner and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the outside environment to within the limits of 10 CFR 100 (Ref. 3). SR 3.6.1.1 leakage rate requirements comply with 10 CFR 50, Appendix J, Option B (Ref. 4), as modified by approved exemptions.

The isolation devices for the penetrations in the containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE automatic containment isolation system, or

   2. Closed by OPERABLE containment isolation boundaries, except as provided in LCO 3.6.3, "Containment Isolation Boundaries."

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks."

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss of coolant accident (LOCA), a steam line break, and a rod ejection accident (REA) (Ref. 5). In addition, release of significant fission product radioactivity within containment can occur from a LOCA or REA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment was originally strength tested at 69 psig (115% of design). The acceptance criteria for this test was 0.1% of the containment air weight per day at 60 psig which was based on the construction techniques that were used (Ref. 5). Following successful completion of this test, the accident analyses were performed assuming a leakage rate of 0.2% of the containment air weight per day. This leakage rate, in combination with the minimum containment engineered safeguards operating (i.e., either 2 post-accident charcoal filter trains and no containment spray, 1 post-accident charcoal filter train and 1 containment spray train, or no post-accident charcoal filter trains and 2 containment spray trains) results in offsite doses well within the limits of 10 CFR 100 (Ref. 3) in the event of a DBA.

The leakage rate of 0.2% of the containment air weight per day is defined in 10 CFR 50, Appendix J, Option B (Ref. 4), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the design basis LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.2% per day in the safety analysis at P_a = 60 psig.

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

Containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$ except prior to entering MODE 4 for the first time following performance of periodic testing performed in accordance with 10 CFR 50, Appendix J, Option B. At that time, the combined Type B and C leakage must be < 0.6 L_a on a maximum pathway leakage rate (MXPLR) basis, and the overall Type A leakage must be < 0.75 L_a. At all other times prior to performing as found testing, the acceptance criteria for Type B and C testing is < 0.6 L_a on a minimum pathway leakage rate (MNPLR) basis. In addition to leakness considerations following a design basis LOCA, containment OPERABILITY also requires structural integrity following a DBA.

Compliance with this LCO will ensure a containment configuration, including personnel and equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

Individual leakage rates specified for the containment air lock (LCO 3.6.2) and mini-purge valves with resilient seals (LCO 3.6.3) and administrative limits for individual isolation boundaries are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the acceptance criteria of Appendix J.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODE 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of this MODE. Therefore, containment is not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from containment. The requirements for containment during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

(continued)

BASES (continued)

ACTIONS

A.1

In the event containment is inoperable, the containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods when containment is inoperable is minimal.

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock and mini-purge valve with resilient seal leakage limits specified in LCO 3.6.2 and LCO 3.6.3 does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes these limits to be exceeded. As left leakage prior to entering MODE 4 for the first time following performance of required 10 CFR 50, Appendix J periodic testing, is required to be < 0.6 L_a for combined Type B and C leakage on a MXPLR basis, and < 0.75 L_a for overall Type A leakage (Ref. 6). At all other times between the required leakage tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. This is maintained by limiting combined Type B and C leakage to < 0.6 L_a on a MXPLR basis until performance of as found testing. At ≤ 1.0 L_a, the offsite dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

SR 3.6.1.2

This SR ensures that the structural integrity of the containment will be maintained in accordance with the provisions of the Containment Tendon Surveillance Program. Testing and Frequency are generally consistent with the recommendations of Regulatory Guide 1.35 (Ref. 7) except that tendon material tests and inspections are not required (Ref. 8).

BASES (continued)

REFERENCES

1. Atomic Industry Forum, GDC 10 and 49, issued for comment July 10, 1967.

2. UFSAR, Section 3.8.1.

3. 10 CFR 100.

4. 10 CFR 50, Appendix J, Option B.

5. UFSAR, Section 6.2.

6. NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 0.

7. Regulatory Guide 1.35, Revision 2.

8. Letter from J. A. Zwolinski, NRC, to R. W. Kober, RG&E, Subject: "Safety Evaluation, Containment Vessel Tendon Surveillance Program," dated August 19, 1985.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

There are two containment air locks installed at Ginna Station, an equipment hatch and a personnel hatch. Both air locks are nominally a right circular cylinder with a door at each end to allow personnel access. The two doors on each airlock are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains a double-tongue, single gasketed seal and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

Each personnel air lock is provided with limit switches on both doors that provide a control board alarm if any door is opened. A single control board alarm exists for all four access doors. Additionally, a control board alarm is provided if high pressure exists between the two doors for either airlock.

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the plant safety analyses.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident (Ref. 1). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.2% of containment air weight per day (Ref. 1). This leakage rate is defined in 10 CFR 50, Appendix J, Option B (Ref. 2), as L_a = 0.2% of containment air weight per day, the maximum allowable containment leakage rate at the calculated peak containment internal pressure P_a = 60 psig following the design basis LOCA. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of the NRC Policy Statement.

LCO

The equipment hatch and personnel hatch containment air locks form part of the containment pressure boundary. As part of containment, the air lock safety function is related to control of the containment leakage rate following a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

(continued)

BASES

LCO (continued)

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the 10 CFR 50, Appendix J Type B air lock leakage test (i.e., SR 3.6.2.1), and both air lock doors must be OPERABLE such that they are closed with leakage within acceptable limits. The interlock allows only one door of an air lock to be opened at a time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into and exit from containment. Normal entry into and exit from containment does not rendered the airlock inoperable.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODE 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of this MODE. Therefore, the containment air locks are not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

(continued)

BASES (continued)

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed to repair. If the inner door is the one that is inoperable, however, then a short time exists when the containment boundary is not intact (during access through the outer door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed. If ALARA conditions permit, entry and exit should be via an OPERABLE air lock.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock.

In the event the air lock leakage results in exceeding the overall containment leakage rate acceptance criteria, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, "Containment." This evaluation should be initiated immediately after declaring a containment air lock inoperable. This is required since the inoperability of an air lock may result in a significant increase in the overall containment leakage rate.

(continued)

BASES

ACTIONS (continued)

A.1, A.2, and A.3

With one air lock door in one or more containment air locks inoperable, the OPERABLE door must be verified closed (Required Action A.1) in each affected containment air lock. If the between air lock door volume exceeds the allowed leakage criteria, and leakage is verified to be into containment (e.g., leakage through the equalizing valve), then the inner airlock door shall be declared inoperable and this Condition entered. If leakage exists from containment to the outside environment, then Condition C is entered. This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour and may consist of verifying the control board alarm status for the airlock doors. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

Required Action A.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means (e.g., procedure control) is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 specifies that Required Actions A.1, A.2, and A.3 are not applicable if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed and Required Actions C.1, C.2, and C.3 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls if both air locks have an inoperable door. This 7 day restriction begins when the second air lock is discovered to be inoperable. Containment entry may be required on a periodic basis to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside containment that are required by TS or activities on equipment that support TS-required equipment. This Note allows performing other activities (i.e., non TS-required activities) if the containment is entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the containment during the short time that the OPERABLE door is expected to be open.

(continued)

BASES

ACTIONS (continued)

B.1, B.2, and B.3

With an air lock interlock mechanism inoperable in one or more air locks, the Required Actions and associated Completion Times are consistent with those specified in Condition A with the exception that both air lock doors are still OPERABLE and either door can be used to isolate the air lock penetration.

The Required Actions have been modified by two Notes. Note 1 specifies that Required Actions B.1, B.2, and B.3 are not applicable if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed and Required Actions C.1, C.2, and C.3 are the appropriate remedial actions. Note 2 allows entry into and exit from containment through an air lock with an inoperable air lock interlock mechanism under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means (e.g., procedure control) is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

(continued)

BASES

ACTIONS (continued)

C.1, C.2, and C.3

With one or more air locks inoperable for reasons other than those described in Condition A or B (e.g., both doors of an airlock are inoperable), Required Action C.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation per LCO 3.6.1 is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within the limits of SR 3.6.2.1. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE per LCO 3.6.1 and it is not necessary to require restoration of the inoperable air lock door within the 1 hour Completion Time specified in LCO 3.6.1 before requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits due to the large margin between the airlock leakage and the containment overall leakage acceptance criteria.

Required Action C.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air lock must be restored to OPERABLE status within the 24 hour Completion Time. The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock and the containment overall leakage rate is acceptable.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established based on industry experience. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is as required by the Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 requires that the results of this SR be evaluated against the acceptance criteria of the Containment Leakage Rate Testing Program. This ensures that air lock leakage is properly accounted for in determining the overall containment leakage rate.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.2.2

The air lock interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and outer doors will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is only challenged when the containment airlock door is opened, this test is only required to be performed once every 24 months. The 24 month Frequency is based on engineering judgment and is considered adequate in view of other indications of door and interlock mechanism status available to operations personnel.

REFERENCES

1. UFSAR, Section 6.2.1.1.
2. 10 CFR 50, Appendix J, Option B.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Boundaries

BASES

BACKGROUND

The containment isolation boundaries form part of the containment pressure barrier and provide a means for fluid penetrations to be provided with two isolation boundaries. These isolation boundaries are either passive or active (automatic). Manual valves, check valves, de-activated automatic valves secured in their closed position, blind flanges, and closed systems are considered passive boundaries. Automatic valves designed to close without operator action following an accident, are considered active boundaries. Two boundaries in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses in accordance with Atomic Industry Forum (AIF) GDC 53 and 57 (Ref. 1). These active and passive boundaries make up the Containment Isolation System.

The Containment Isolation System is designed to provide isolation capability following a Design Basis Accident (DBA) for all fluid lines which penetrate containment. All major nonessential lines (i.e., fluid systems which do not perform an immediate accident mitigation function) which penetrate containment, except for the main feedwater lines, component cooling water to the reactor coolant pumps, and main steam lines, are either automatically isolated following an accident or are normally maintained closed in MODES 1, 2, 3, and 4. Automatic containment isolation valves are designed to close on a containment isolation signal which is generated by either an automatic safety injection (SI) signal or by manual actuation. The Containment Isolation System can also isolate essential lines at the discretion of the operators depending on the accident progression and mitigation. As a result, the containment isolation boundaries help ensure that the containment atmosphere will be isolated from the outside environment in the event of a release of fission product radioactivity to the containment atmosphere as a result of a DBA.

(continued)

BASES

BACKGROUND (continued)

The OPERABILITY requirements for containment isolation boundaries help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

In addition to the normal fluid systems which penetrate containment, there are two systems which can provide direct access from inside containment to the outside environment.

Shutdown Purge System (36 inch purge valves)

The Shutdown Purge System operates to supply outside air into the containment for ventilation and cooling or heating and may also be used to reduce the concentration of noble gases within containment prior to and during personnel access below MODE 4. The supply and exhaust lines each contain one isolation valve and one double gasketed blind flange. Because of their large size, the shutdown purge valves are not qualified for automatic closure from their open position under DBA conditions. Also, due to the design of the blind flange assembly, the isolation valve is not required to be credited as a containment isolation barrier. Therefore, the blind flanges are installed in MODES 1, 2, 3, and 4 to ensure that the containment barrier is maintained (Ref. 2).

Mini-Purge System (6 inch purge valves)

The Mini-Purge System operates to:

a. Reduce the concentration of noble gases within containment prior to and during personnel access, and

b. Equalize internal and external pressures.

(continued)

BASES

BACKGROUND

Mini-Purge System (6 inch purge valves) (continued)

The system is designed with supply and exhaust lines both of which contain two air operated isolation valves. Since the valves used in the Mini-Purge System are designed to meet the requirements for automatic containment isolation valves, these valves may be opened as needed in MODES 1, 2, 3, and 4; however, emphasis shall be placed on limiting purging and venting times to as low as reasonably achievable.

APPLICABLE SAFETY ANALYSES

The containment isolation boundary LCO was derived from the assumptions related to minimizing the loss of reactor inventory and establishing the containment barrier during major accidents. As part of the containment barrier, OPERABILITY of devices which act as containment isolation boundaries supports leak tightness of the containment. Therefore, the safety analyses of any event requiring isolation of containment is applicable to this LCO.

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident (LOCA) and a rod ejection accident (Ref. 3). Other DBAs (e.g., locked rotor) result in the release of radioactive material within the reactor coolant system. In the analyses for each of these accidents, it is assumed that containment isolation boundaries are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment and other systems through containment isolation boundaries (including containment mini-purge valves) are minimized. The safety analyses assume that the Shutdown Purge System is isolated at event initiation.

In the calculation of control room and offsite doses following a LOCA (rod ejection accident is assumed to be bounding), the accident analyses assume that 25% of the equilibrium iodine inventory and 100% of the equilibrium noble gas inventory developed from maximum full power operation of the core is immediately available for leakage from containment (Ref. 4). The containment is assumed to leak at the design leakage rate, L_a, for the first 24 hours of the accident and at 50% of this leakage rate for the remaining duration of the accident.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The containment isolation boundaries ensure that the containment design leakage rate remains within L_a by automatically isolating penetrations that do not serve post accident functions and providing isolation capability for penetrations associated with Engineered Safeguards Functions. The maximum isolation time for automatic containment isolation valves is 60 seconds (Ref. 3). This isolation time is based on engineering judgement since the control room and offsite dose calculations are performed assuming that leakage from containment begins immediately following the accident with no credit for transport time or radionuclide decay. The 60 second isolation time takes into consideration the time required to drain piping of fluid which can provide an initial containment barrier before the containment isolation valves are required to close and the conservative assumptions with respect to core damage occurring immediately following the accident. The containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (only for motor operated valves affected by a loss of offsite power), and containment isolation valve stroke times.

The containment mini-purge valves are air operated valves which have isolation times shorter than 60 seconds since these penetrations may be opened and provide direct access to the outside environment. The accident analyses assume that these valves close prior to a hot rod burst (20 seconds) which occurs following a large break LOCA since the hot rod burst directly leads to higher radiation concentrations within containment. A 5 second isolation time for the mini-purge valves is used for additional conservatism (Ref. 3). The 5 second total isolation response time includes signal delay and containment isolation valve stroke times.

Containment isolation is also required for events which result in hot rod bursts but do not breach the integrity of the RCS (e.g., locked rotor accident). The isolation of containment following these events also isolates the RCS from all non essential systems to prevent the release of radioactive material outside the RCS. The containment isolation time requirements for these events are bounded by those for the LOCA.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The Containment Isolation System is designed to provide two in series boundaries for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds the limits in the safety analyses. This system was originally designed in accordance with AIF GDC 53 (Ref. 1) which does not contain the specific design criteria specified in 10 CFR 50, Appendix A, GDC 55, 56, and 57 (Ref. 5). In general, the Containment Isolation System meets the current GDC requirements; however, several penetrations differ from the GDC from the standpoint of installed valve type (e.g., check valve versus automatic isolation valve) or valve location (e.g., both containment isolation boundaries are located inside containment). The evaluation of these penetrations is provided in Reference 3.

The containment isolation boundaries satisfy Criterion 3 of the NRC Policy Statement.

LCO

Containment isolation boundaries form a part of the containment pressure barrier. The containment isolation boundaries' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment barrier leakage rates during a DBA.

The boundaries covered by this LCO are listed in Reference 6. These boundaries consist of isolation valves (manual valves, check valves, air operated valves, and motor operated valves), pipe and end caps, closed systems, and blind flanges. There are three major categories of containment isolation boundaries which are used depending on the type of penetration and the safety function of the associated piping system:

a. Automatic containment isolation boundaries which receive a containment isolation signal to close following an accident;

(continued)

BASES

LCO
(continued)

b. Normally closed containment isolation boundaries which are maintained closed in MODES 1, 2, 3, and 4 since they do not receive a containment isolation signal to close and the penetration is not used for normal power operation (but may be used for a long term accident mitigation function); and

c. Normally open, but nonautomatic containment isolation boundaries which are maintained open since the penetrations are required for normal power operation. Penetrations which utilize these type of isolation boundaries also contain a passive device (i.e., closed system), such that the normally open, but nonautomatic isolation boundary is only closed after the first passive boundary has failed.

The automatic containment isolation boundaries (i.e., valves) are considered OPERABLE when they are capable of closing within the stroke time specified in Reference 6. The normally closed containment isolation boundaries are considered OPERABLE when the manual valves are closed, air operated or motor operated valves are de-activated and secured in their closed position, check valves are closed with flow secured through the valve, blind flanges, pipe and end caps are in place, and closed systems are intact. The normally open, but nonautomatic, containment isolation boundaries (e.g. check valves and manual valves) are considered OPERABLE when they are capable of being closed. In addition, both penetrations associated with the Shutdown Purge System must be isolated by a blind flange containing redundant gaskets, or a single gasketed blind flange with a de-activated automatic isolation valve (i.e., two passive barriers).

Containment isolation boundary leakage per 10 CFR 50, Appendix J, Type B and C testing, is only addressed by LCO 3.6.1, "Containment," and is not a consideration in determination of containment isolation boundary OPERABILITY.

(continued)

BASES

LCO (continued)

This LCO provides assurance that the containment isolation boundaries will perform their designed safety functions to control leakage from the containment during DBAs.

The LCO is modified by three Notes. The first Note states that the LCO is not applicable to the main steam safety valves in MODES 1, 2, and 3. These valves are addressed by LCO 3.7.1, "Main Steam Safety Valves (MSSVs)," which provides appropriate Required Actions in the event these valves are declared inoperable.

The second Note states that the LCO is not applicable to the main steam isolation valves (MSIVs) in MODE 1, and in MODES 2 and 3 with the MSIVs open or closed and not deactivated. These valves are addressed by LCO 3.7.2, "Main Steam Isolation Valves (MSIVs) and Non-Return Check Valves."

The third Note states that the atmospheric relief valves are not addressed by this LCO in MODES 1 and 2, and MODE 3 when the Reactor Coolant System average temperature (T_{avg}) is ≥ 500°F. These valves are addressed by LCO 3.7.4, "Atmospheric Relief Valves (ARVs)," which provides appropriate Required Actions in the event these valves are declared inoperable.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODE 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of this MODE. Therefore, the containment isolation boundaries are not required to be OPERABLE in MODE 5. The requirements for containment isolation boundaries during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

(continued)

BASES (continued)

ACTIONS

The ACTIONS are modified by four Notes. The first Note allows penetration flow paths, except for the Shutdown Purge System valve penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated individual qualified in accordance with plant procedures at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated. Due to the size of the shutdown purge line penetration and the fact that these penetrations exhaust directly from the containment atmosphere to the outside environment, the penetration flow path containing these valves may not be opened under administrative controls.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable containment isolation boundary. Complying with the Required Actions may allow for continued operation, and subsequent inoperable containment isolation boundaries are governed by subsequent Condition entry and application of associated Required Actions.

A third Note has been added which ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation boundary, or as the result of performing the Required Actions described below.

(continued)

BASES

ACTIONS (continued)

Finally, in the event the isolation boundary leakage results in exceeding the overall containment leakage rate acceptance criteria, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1. This evaluation should be initiated immediately after declaring a containment isolation boundary inoperable. This is required since the inability of an isolation boundary to close may result in a significant increase in the overall containment leakage rate if the in-series and redundant isolation boundary has a large "as-left" leakage rate associated with it.

<u>A.1 and A.2</u>

In the event one containment isolation boundary in one or more penetration flow paths is inoperable (except for mini-purge valve leakage not within limit), the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation boundary that cannot be adversely affected by a single active failure. Isolation boundaries that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For a penetration flow path isolated in accordance with Required Action A.1, the boundary used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no longer capable of being isolated following a single failure will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification, through a system walkdown, that those isolation boundaries capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation boundaries outside containment" is appropriate considering the fact that the boundaries are operated under administrative controls and the probability of their misalignment is low. For the isolation boundaries inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation boundaries and other administrative controls that will ensure that isolation boundary misalignment is an unlikely possibility.

Required Action A.2 is modified by a Note that applies to isolation boundaries located in high radiation areas and allows these boundaries to be verified closed by use of administrative means (e.g., ensuring that all valve manipulations in these areas have been independently verified). Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these boundaries, once they have been verified to be in the proper position, is small.

Condition A has been modified by a Note indicating that this Condition is only applicable to those penetration flowpaths which do not use a closed system as a containment isolation boundary. For those penetrations which do use a closed system, Condition C provides the appropriate actions.

(continued)

BASES

ACTIONS (continued)

B.1

With two containment isolation boundaries in one or more penetration flow paths inoperable (except for mini-purge valve leakage not within limit), the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation boundary that cannot be adversely affected by a single active failure. Isolation boundaries that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. Check valves and closed systems are not acceptable isolation boundaries in this instance since they cannot be assured to meet the design requirements of a normal containment isolation boundary. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.

Following completion of Required Action B.1, verification that the affected penetration flow path remains isolated must be performed in accordance with Required Action A.2.

Condition B is modified by a Note indicating that this Condition is only applicable to penetration flow paths which do not use a closed system as containment isolation boundary. For those penetrations which do use a closed system, Condition C provides the appropriate actions.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With one or more penetration flow paths with one containment isolation boundary inoperable, the inoperable boundary flow path must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. This Required Action does not require any testing or device manipulation. Rather, it involves verification through a system walkdown, that these isolation boundaries capable of being mispositioned are in the correct position. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of "once per 31 days for isolation boundaries outside containment" is appropriate considering the fact that the boundaries are operated under administrative controls and the probability of their misalignment is low. For the isolation boundaries inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation boundaries and other administrative controls that will ensure that isolation boundary misalignment is an unlikely possibility.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths which use a closed system as a containment isolation boundary. This Note is necessary since this Condition is written to specifically address those penetration flow paths which utilize a closed system as defined in Reference 7.

Required Action C.2 is modified by a Note that applies to isolation boundaries located in high radiation areas and allows these boundaries to be verified closed by use of administrative means (e.g., ensuring that all valve manipulations in these areas have been independently verified). Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these devices, once they have been verified to be in the proper position, is small.

D.1

In the event one or more containment mini-purge penetration flow paths contain one valve not within the mini-purge valve leakage limits, mini-purge valve leakage must be restored to within limits, or the affected penetration flow path must be isolated. The method of isolation must be by the use of at least one isolation boundary that cannot be adversely affected by a single active failure. Isolation boundaries that meet this criterion are a closed and de-activated automatic valve, closed manual valve, or blind flange. A purge valve with resilient seals utilized to satisfy Required Action D.1 must have been demonstrated to meet the leakage requirements of SR 3.6.3.5. The specified Completion Time is reasonable, considering that one containment purge valve remains closed so that a major violation of containment does not exist.

(continued)

BASES

ACTIONS (continued)

D.2

In accordance with Required Action D.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those isolation boundaries and capable of being mispositioned are in the correct position. The Completion Time of "once every 31 days for isolation boundaries outside containment" is appropriate considering the fact that the boundaries are operated under administrative controls and the probability of their misalignment is low. For the isolation boundaries inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation boundaries and other administrative controls that will ensure that isolation boundary misalignment is an unlikely possibility.

Required Action D.2 is modified by a Note that applies to isolation boundaries located in high radiation areas and allows these boundaries to be verified closed by use of administrative means (e.g., ensuring that all valve manipulations in these areas have been independently verified). Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these boundaries, once they have been verified to be in the proper position, is small.

(continued)

BASES

ACTIONS (continued)

E.1

In the event one or more containment mini-purge penetration flow paths contain two valves not within the mini-purge valve leakage limits, Required Action E.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current mini-purge results. An evaluation per LCO 3.6.1 is acceptable, since it is overly conservative to immediately declare the containment inoperable if both mini-purge valves have failed a leakage test or are not within the limits of SR 3.6.3.5. In many instances, containment remains OPERABLE per LCO 3.6.1 and it is not necessary to require restoration of the mini-purge penetration flow path within the 1 hour Completion Time specified in LCO 3.6.1 before requiring a plant shutdown. In addition, even with both valves failing the leakage test, the overall containment leakage rate can still be within limits due to the large margin between the mini-purge valve leakage and the containment overall leakage acceptance criteria.

E.2

Required Action E.2 requires that the mini-purge valve leakage must be restored to within limits, or the affected penetration flow path must be isolated within 1 hour. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, closed manual valve, or blind flange. A purge valve with resilient seals utilized to satisfy Required Action E.2 must have been demonstrated to meet the leakage requirements of SR 3.6.3.5. The specified Completion Time is reasonable, considering that one containment purge valve remains closed so that a major violation of containment does not exist.

Following completion of Required Action E.1, verification that the affected penetration flow path remains isolated must be performed in accordance with Required Action D.2.

(continued)

BASES

ACTIONS (continued)	F.1 and F.2

ACTIONS (continued)

F.1 and F.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

This SR ensures that the mini-purge valves are closed except when the valves are opened under administrative control. The mini-purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The valves may be opened for pressure control, ALARA or air quality considerations for personnel entry, maintenance activities, or for Surveillances that require the valves to be open. To be opened, the valves must be capable of closing under accident conditions, the containment isolation signal to the valves must be OPERABLE, and the effluent release must be monitored to ensure that it remains within regulatory limits. The 31 day Frequency is based on the relative importance of these valves since they provide a direct path to the outside environment and the administrative controls that are in place.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.2

This SR requires verification that each containment isolation boundary located outside containment and not locked, sealed or otherwise secured in the required position is performing its containment isolation accident function. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment barrier is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those isolation boundaries outside containment and capable of being mispositioned are in the correct position. This includes manual valves, blind flanges, pipe and end caps, and closed systems. Since containment isolation boundaries are maintained under administrative controls with containment isolation boundary tags installed, the probability of their misalignment is low and a 92 day Frequency to verify their correct position is appropriate. The SR specifies that isolation boundaries that are open under administrative controls are not required to meet the SR during the time the boundaries are open.

The SR is modified by two notes. The first Note applies to containment isolation boundaries located in high radiation areas and allows these boundaries to be verified closed by use of administrative means. Allowing verification by administrative means (e.g., procedure control) is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3 and 4 for ALARA reasons. Therefore, the probability of misalignment of these isolation boundaries, once they have been verified to be in the proper position, is small. The Second Note states that this SR is not applicable to containment isolation boundaries which receive an automatic signal since the isolation times of these valves are verified by SR 3.6.3.4 and the boundaries are required to be OPERABLE.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.3

This SR requires verification that each containment isolation boundary located inside containment and not locked, sealed or otherwise secured in the required position and is performing its containment isolation accident function. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment barrier is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those isolation boundaries inside containment and capable of being mispositioned are in the correct position. This includes manual valves, blind flanges, pipe and end caps, and closed systems. Since containment isolation boundaries are maintained under administrative controls with containment isolation boundary tags installed, the probability of their misalignment is low and Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate. The SR specifies that isolation boundaries that are open under administrative controls are not required to meet the SR during the time they are open.

The SR is modified by two notes. The first Note applies to containment isolation boundaries located in high radiation areas and allows these boundaries to be verified closed by use of administrative means. Allowing verification by administrative means (e.g., procedure control) is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4 for ALARA reasons. Therefore, the probability of misalignment of these isolation boundaries, once they have been verified to be in the proper position, is small. The Second Note states that this SR is not applicable to containment isolation boundaries which receive an automatic signal since the signal provides assurance the valve will be closed following an accident.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.4

Verifying that the isolation time of each automatic containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are in accordance with the Inservice Testing Program.

SR 3.6.3.5

For containment mini-purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J, Option B, is required to ensure OPERABILITY. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. Based on this observation and the importance of maintaining this penetration leak tight (due to the direct path between containment and the outside environment), a leakage acceptance criteria of $\leq 0.05\ L_a$ when tested at $\geq P_a$ is specified for each mini-purge isolation valve with resilient seals in the Containment Leakage Rate Testing Program. The Frequency of testing is also specified in the Containment Leakage Rate Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.6

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Atomic Industry Forum GDC 53 and 57, issued for comment July 10, 1967.
2. Branch Technical Position CSB 6-4, "Containment Purging During Normal Operation."
3. UFSAR, Section 6.2.4 and Table 6.2-15.
4. Regulatory Guide 1.4, Revision 2.
5. 10 CFR 50, Appendix A, GDC 55, 56, and 57.
6. Ginna Station Procedure A-3.3.
7. NUREG-0800, Section 6.2.4.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND	The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) and steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere. Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a DBA, post accident containment pressures could exceed calculated values. Exceeding containment design pressure may result in leakage greater than that assumed in the accident analysis. Operation with containment pressure outside the limits of the LCO violates an initial condition assumed in the accident analysis.
APPLICABLE SAFETY ANALYSES	Containment internal pressure is an initial condition used in the DBA analyses performed to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer codes designed to predict the resultant containment pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The worst case SLB generates larger mass and energy releases than the worst case LOCA. Thus, the SLB event bounds the LOCA event from the containment peak pressure standpoint (Ref. 1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The initial pressure condition used in the containment analysis was 15.7 psia (1.0 psig). The maximum containment pressure resulting from the worst case SLB, 59.8 psig, does not exceed the containment design pressure, 60 psig.

The containment was also designed for an external pressure load equivalent to -2.5 psig. However, internal pressure is limited to -2.0 psig based on concerns related to providing continued cooling for the reactor coolant pump motors inside containment.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. Therefore, for the reflood phase, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50, Appendix K (Ref. 2). Service Water System (LCO 3.7.8) temperature plays an important role in both maximizing and minimizing containment pressure following a DBA response.

Containment pressure satisfies Criterion 2 of the NRC Policy Statement.

LCO

Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit ensures that the containment will not exceed the design negative differential pressure. However, the lower pressure limit specified for this LCO is set at a more limiting pressure to ensure continued cooling of the reactor coolant pump motors inside containment which are required to be OPERABLE for a large portion of MODES 1, 2, 3, and 4.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analyses are maintained, the LCO is applicable in MODES 1, 2, 3 and 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODE 5 or 6.

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, it must be restored to within these limits within 8 hours. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is greater than the ACTIONS of LCO 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour. However, due to the large containment free volume and limited size of the containment Mini-Purge System, 8 hours is allowed to restore containment pressure to within limits. This is justified by the low probability of a DBA during this time period.

B.1 and B.2

If containment pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that containment pressure is within limits ensures that plant operation remains within the limits assumed in the containment analysis. This verification should normally be performed using PI-944. The 12 hour Frequency of this SR was developed based on operating experience related to trending of containment pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment pressure condition.

Calibration of PI-944 or other containment pressure monitoring devices should be performed in accordance with industry standards.

REFERENCES

1. UFSAR, Section 6.2.1.2.
2. 10 CFR 50, Appendix K.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Air Temperature

BASES

BACKGROUND

The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment average air temperature is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) and steam line break (SLB).

The containment average air temperature limit is derived from the input conditions used in the containment functional analyses and the containment structure external pressure analyses. This LCO ensures that initial conditions assumed in the analysis of containment response to a DBA are not violated during plant operations. The total amount of energy to be removed from containment by the Containment Spray (CS) and Containment Recirculation Fan Cooler (CRFC) Systems during post accident conditions is dependent upon the energy released to the containment due to the event, as well as the initial containment temperature and pressure. The higher the initial temperature, the more energy that must be removed, resulting in higher peak containment pressure and temperature. Exceeding containment design pressure may result in leakage greater than that assumed in the accident analysis. Operation with containment temperature in excess of the LCO limit violates an initial condition assumed in the accident analysis.

APPLICABLE SAFETY ANALYSES

Containment average air temperature is an initial condition used in the DBA analyses to ensure that the total amount of energy within containment is within the capacity of the CS and CRFC Systems. The containment average air temperature is also an important consideration in establishing the containment environmental qualification operating envelope for both pressure and temperature. The limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analyses for containment (Ref. 1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting DBAs considered relative to containment OPERABILITY are the LOCA and SLB which are analyzed using computer codes designed to predict the resultant containment pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to the capability of the Engineered Safety Feature (ESF) systems to mitigate the accident, assuming the worst case single active failure. Consequently, the ESF systems must continue to function within the environment resulting from the DBA which includes humidity, pressure, temperature, and radiation considerations.

The limiting DBA for the maximum peak containment air temperature is an SLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 120°F. This results in a maximum containment air temperature of 374°F.

The initial temperature limit specified in this LCO is also used to establish the environmental qualification operating envelope for containment. The maximum SLB peak containment air temperature was calculated to exist for only a few seconds during the transient. The basis of the containment design temperature, however, is to ensure the performance of safety related equipment inside containment (Ref. 2). Thermal analyses show that the time interval during which the containment air temperature peaked was short enough that the equipment surface temperatures remained below their design temperatures. Also, the equipment and cabling inside containment are protected against the direct effects of a SLB by concrete floors and shields. Therefore, it was concluded that the calculated transient containment air temperature following a LOCA (286°F) becomes limiting for environmental qualification reasons.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure is a SLB. The temperature limit is used in this analysis to ensure that in the event of an accident the maximum allowable containment internal pressure will not be exceeded.

Containment average air temperature satisfies Criterion 2 of the NRC Policy Statement.

LCO

During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature is maintained below the containment design temperature. As a result, the ability of containment to perform its design function is ensured and the OPERABILITY of equipment within containment is maintained.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODE 5 or 6.

ACTIONS

A.1

When containment average air temperature is not within the limit of the LCO, it must be restored to within the limit within 24 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 24 hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the containment average air temperature cannot be restored to within its limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Verifying that containment average air temperature is within the LCO limit ensures that containment operation remains within the limit assumed for the containment analyses. In order to determine the containment average air temperature, an arithmetic average is calculated using measurements taken at locations within the containment selected to provide a representative sample of the overall containment atmosphere. There are 6 containment air temperature indicators (TE-6031, TE-6035, TE-6036, TE-6037, TE-6038, and TE-6045) such that a minimum of three should be used for calculating the arithmetic average. The 12 hour Frequency of this SR is considered acceptable based on observed slow rates of temperature increase within containment as a result of environmental heat sources (due to the large volume of containment). Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to an abnormal containment temperature condition.

Calibration of these temperature indicators shall be performed in accordance with industry standards.

REFERENCES

1. UFSAR, Section 6.2.1.2.

2. 10 CFR 50.49.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray (CS), Containment Recirculation Fan Cooler (CFRC), NaOH, and Containment Post-Accident Charcoal Systems

BASES

BACKGROUND

The CS and CRFC systems provide containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine removal capability of the CS System, NaOH System, and the Containment Post-Accident Charcoal System connected to the CRFC units reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA), to within limits. The CS, CRFC, NaOH, and Containment Post-Accident Charcoal Systems are designed to meet the requirements of Atomic Industry Forum (AIF) GDC 49, 52, 58, 59, 60, and 61 (Ref. 1). The CS, NaOH, and Post-Accident Charcoal Systems also are designed to limit offsite doses following a DBA within 10 CFR 100 guidelines.

The CRFC System, CS System, NaOH System, and the Containment Post-Accident Charcoal System are Engineered Safety Feature (ESF) systems. They are designed to ensure that the heat removal capability required during the post accident period can be attained and reduce the potential release of radioactive material, principally iodine, from the containment to the outside environment. The CS System, CRFC System, NaOH System, and the Containment Post-Accident Charcoal System provide redundant methods to limit and maintain post accident conditions to less than the containment design values.

(continued)

BASES

BACKGROUND (continued)

Containment Spray and NaOH Systems

The CS System consists of two redundant, 100% capacity trains. Each train includes a pump, spray headers, spray eductors, nozzles, valves, and piping (see Figure B 3.6.6-1). Each train is powered from a separate ESF bus. The refueling water storage tank (RWST) supplies borated water to the CS System during the injection phase of operation through a common supply header shared by the safety injection (SI) system. In the recirculation mode of operation, CS pump suction can be transferred from the RWST to Containment Sump B via the residual heat removal (RHR) system.

The CS System provides a spray of cold borated water mixed with sodium hydroxide (NaOH) from the spray additive tank into the upper regions of containment to reduce the containment pressure and temperature and to scavenge fission products from the containment atmosphere during a DBA. The RWST solution temperature is an important factor in determining the heat removal capability of the CS System during the injection phase. In the recirculation mode of operation, heat is removed from the containment sump water by the residual heat removal coolers. However, the CS System can provide additional containment heat removal capability if required. Each train of the CS System provides adequate spray coverage to meet the system design requirements for containment heat removal.

The NaOH mixture is injected into the CS flowpath via a liquid eductor during the injection phase of an accident. The eductors are designed to ensure that the pH of the spray mixture is between 8.3 and 9.1. The resulting alkaline pH of the spray enhances the ability of the spray to scavenge fission products from the containment atmosphere. The NaOH added in the spray also ensures an alkaline pH for the solution recirculated in the containment sump. The alkaline pH of the containment sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid (Ref. 2).

(continued)

BASES

BACKGROUND

Containment Spray and NaOH Systems (continued)

The CS System is actuated either automatically by a containment Hi-Hi pressure signal or manually. DBAs which can generate an automatic actuation signal include the loss of coolant accident (LOCA) and steam line break (SLB). An automatic actuation opens the CS pump motor operated discharge valves (860A, 860B, 860C, and 860D), opens NaOH addition valves 836A and 836B, starts the two CS pumps, and begins the injection phase. A manual actuation of the CS System requires the operator to actuate two separate pushbuttons simultaneously on the main control board to begin the same sequence. The injection phase continues until an RWST low level alarm is received signaling the start of the recirculation phase of the accident.

During the recirculation phase of LOCA recovery, RHR pump suction is manually transferred to Containment Sump B (Refs. 3 and 4). This transfer is accomplished by stopping the RHR pumps, isolating RHR from the RWST by closing motor operated valve 856, opening the Containment Sump B motor operated isolation valves to RHR (850A and 850B) and then starting the RHR pumps. The SI and CS pumps are then stopped and the RWST isolated by closing motor operated isolation valve 896A or 896B for the SI and CS pump common supply header and closing motor operated isolation valve 897 or 898 for the SI pumps recirculation line.

The RHR pumps then supply the SI pumps if the RCS pressure remains above the RHR pump shutoff head as correlated through core exit temperature, containment pressure, and reactor vessel level indications (Ref. 5). This high-head recirculation path is provided through RHR motor operated isolation valves 857A, 857B, and 857C. These isolation valves are interlocked with 896A, 896B, 897, and 898. This interlock prevents opening of the RHR high head recirculation isolation valves unless either 896A or 896B are closed and either 897 or 898 are closed. If RCS pressure is such that RHR provides adequate injection flow for core cooling, the SI pumps remain in pull-stop.

(continued)

BASES

BACKGROUND

Containment Spray and NaOH Systems (continued)

The CS System is only used during the recirculation phase if containment pressure increases above a pressure at which containment integrity is potentially challenged. Otherwise, the containment heat removal provided by the CRFC units and Containment Sump B (via the RHR system) is adequate to support containment heat removal needs and the limits on sump pH (Refs. 2 and 6).

Operation of the CS System in the recirculation mode is controlled by the operator in accordance with the emergency operating procedures.

Containment Recirculation Fan Cooler System

The CRFC System consists of four fan units (A, B, C, and D). Each cooling unit consists of a motor, fan, cooling coils, dampers, moisture separators, high efficiency particulate air (HEPA) filters, duct distributors and necessary instrumentation and controls (see Figure B 3.6.6-2). The moisture separators function to reduce the moisture content of the airstream to support the effectiveness of the post-accident charcoal filters. CRFC units A and D are supplied by one ESF bus while CRFC units B and C are supplied by a redundant ESF bus. All four CRFC units are supplied cooling water by the Service Water (SW) System via a common loop header. Air is drawn into the coolers through the fan and discharged into the containment atmosphere including the various compartments (e.g., steam generator and pressurizer compartments).

During normal operation, at least two fan units are typically operating. The CRFC System, operating in conjunction with other containment ventilation and air conditioning systems, is designed to limit the ambient containment air temperature during normal plant operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

(continued)

BASES

BACKGROUND

<u>Containment Recirculation Fan Cooler System</u> (continued)

In post accident operation following a SI actuation signal, the CRFC System fans are designed to start automatically if not already running. The discharge of CRFC units A and C then transfer to force flow through the post-accident charcoal filters. The temperature of the cooling water supplied by SW System (LCO 3.7.8) is an important factor in the heat removal capability of the fan units.

<u>Containment Post-Accident Charcoal System</u>

The Containment Post-Accident Charcoal System consists of two redundant, 100% capacity trains. Each train includes an airtight plenum containing two banks of charcoal filter cells for removal of radioiodines (see Figure 3.6.6-2). Air flow enters the plenum through two holes in the bottom (one at each end), passes through the charcoal filter banks to the center, and is exhausted from the plenum through a hole in the top. Two normally closed air operated dampers isolate each post-accident charcoal filter train from CRFC units A and C (dampers 5871 and 5872 for Train A and 5874 and 5876 for Train B). A SI signal opens these dampers and closes two bypass dampers from the CRFC units (dampers 5873 for CRFC unit A and 5875 for CRFC unit C) to force flow through the post-accident charcoal filters.

APPLICABLE SAFETY ANALYSES

The CS System and CRFC System limit the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the LOCA and the SLB which are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF systems, assuming the worst case single active failure.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is 59.8 psig and the peak containment temperature is 374°F (both experienced during an SLB). Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5," Containment Temperature," for a detailed discussion.) The analyses and evaluations assume a plant specific power level of 102%, one CS train and one containment cooling train operating, and initial (pre-accident) containment conditions of 120°F and 1.0 psig. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50, Appendix K (Ref. 7).

The effect of an inadvertent CS actuation is not considered since there is no single failure, including the loss of offsite power, which results in a spurious CS actuation.

The modeled CS System actuation for the containment analysis is based on a response time associated with exceeding the containment Hi-Hi pressure setpoint to achieving full flow through the CS nozzles. To increase the response of the CS System, the injection lines to the spray headers are maintained filled with water. The CS System total response time of 37.5 seconds (assuming the containment Hi-Hi pressure is reached at time zero) includes diesel generator (DG) startup (for loss of offsite power), opening of the motor operated isolation valves, containment spray pump startup, and spray line filling (Ref. 8).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The modeled CRFC System actuation for the containment analysis is based upon a response time associated with exceeding the SI actuation levels to achieving full CRFC System air and safety grade cooling water flow. The CRFC System total response time of 44 seconds, includes signal delay, DG startup (for loss of offsite power), and service water pump and CRFC unit startup times (Ref. 9).

During a SLB or LOCA, a minimum of two CRFC units and one CS train are required to maintain containment peak pressure and temperature below the design limits.

The CS, NaOH, and Containment Post-Accident Charcoal Systems operate to reduce the release of fission product radioactivity from containment to the outside environment in the event of a DBA. The DBAs that result in a release of radioactive iodine within containment are the LOCA or a rod ejection accident (REA). In the analysis for each of these accidents, it is assumed that adequate containment leak tightness is intact at event initiation to limit potential leakage to the environment. Additionally, it is assumed that the amount of radioactive iodine released is limited by reducing the iodine concentration present in the containment atmosphere.

The required iodine removal capability of the CS, NaOH, and Containment Post-Accident Charcoal Systems is established by the consequences of the limiting DBA, which is a LOCA. The accident analyses (Ref. 10) assume that either two trains of CS (taking suction from the NaOH System), one CS train and one post-accident charcoal filter train, or two post-accident charcoal filter trains operate to remove radioactive iodine from the containment atmosphere.

The CS System, NaOH System, CRFC System, NaOH System, and the Containment Post-Accident Charcoal System satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

During a DBA, a minimum of 2 CRFC units and one CS train are required to maintain the containment peak pressure and temperature below the design limits (Ref. 8). Additionally, two CS trains taking suction from the NaOH System, two CRFC units with post accident charcoal filters (i.e., units A and C), or one CRFC unit with post accident charcoal filters in combination with one CS train are also required to remove iodine from the containment atmosphere and maintain concentrations below those assumed in the safety analysis. To ensure that these requirements are met, two CS trains, four CRFC units, and two post-accident charcoal filter trains and the NaOH System must be OPERABLE. Therefore, in the event of an accident, at least one CS and post-accident charcoal filter train, the NaOH System, and two CRFC units operates, assuming the worst case single active failure occurs.

Each CS train includes a spray pump, spray headers, nozzles, valves, spray eductors, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal and manually transferring suction to Containment Sump B via the RHR pumps.

For the NaOH System to be OPERABLE, the volume and concentration of spray additive solution in the tank must be within limits and air operated valves 836A and 836B must be OPERABLE.

Each CRFC unit includes a motor, fan cooling coils, dampers, moisture separators, HEPA filters, duct distributors, instruments, and controls to ensure an OPERABLE flow path. For CRFC units A and C, flow through either the post-accident charcoal filter or the bypass is required for the units to be considered OPERABLE.

Each post-accident charcoal filter train includes a plenum containing charcoal filter banks and isolation dampers to ensure an OPERABLE flow path. CRFC units A and C are also required to be OPERABLE.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature requiring the operation of the CS System, CRFC System, NaOH System, and the Post-Accident Charcoal System.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the CS System, CRFC System, NaOH System, and the Post-Accident Charcoal System are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one CS train inoperable, the inoperable CS train must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE spray and CRFC units are adequate to perform the iodine removal and containment cooling functions. The 72 hour Completion Time takes into account the redundant heat removal capability afforded by the CS System, the redundant iodine removal afforded by the Containment Post-Accident Charcoal System, reasonable time for repairs, and low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

With one post-accident charcoal filter train inoperable, the inoperable train must be restored to OPERABLE status within 7 days. Each post-accident charcoal filter train is capable of providing 50% of the radioactive iodine removal requirements following a DBA. The loss of CRFC unit A or C also results in its associated post-accident charcoal filter train being inoperable since the post-accident charcoal filter trains do not have their own fan assembly. The 7 day Completion Time of Required Action B.1 to restore the inoperable post-accident charcoal filter train, including the CRFC unit, is justified considering the redundant iodine removal capabilities afforded by the CS and NaOH Systems and the low probability of a DBA occurring during this time period.

C.1

With both post-accident charcoal filter trains inoperable, at least one post-accident charcoal filter train must be restored to OPERABLE status within 72 hours. The 72 hour Completion Time to restore one inoperable post-accident charcoal filter train is justified considering the redundant iodine removal capabilities afforded by the CS System and the low probability of a DBA occurring during this time period. The inoperable post-accident charcoal filter train includes, but is not limited to inoperable CRFC units A and C.

D.1

With the NaOH System inoperable, OPERABLE status must be restored within 72 hours. The 72 hour Completion Time to restore the NaOH System is justified considering the redundant iodine removal capabilities afforded by the Containment Post-Accident Charcoal System and the low probability of a DBA occurring during this time period.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

If the inoperable CS train, post-accident charcoal filter trains, or the NaOH System cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows additional time for attempting restoration of the inoperable component(s) and is reasonable when considering the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

F.1 and F.2

With one or two CRFC units inoperable, the affected post-accident charcoal filter must be declared inoperable immediately and the inoperable CRFC unit(s) must be restored to OPERABLE status within 7 days. The inoperable CRFC units provided up to 100% of the containment heat removal needs and up to 50% of the iodine removal needs. The 7 day Completion Time is justified considering the redundant heat removal capabilities afforded by combinations of the CS System and CRFC System and the low probability of DBA occurring during this period. If both CRFC units A and C are inoperable, then Condition C must also be entered.

Required Action F.1 is modified by a Note which states that this required action is only applicable if CRFC unit A or C is inoperable. The loss of CRFC unit A or C results in the associated post-accident charcoal filter train being inoperable since the post-accident charcoal filter trains do not have their own fan assembly.

(continued)

BASES

ACTIONS (continued)

G.1 and G.2

If the Required Action and associated Completion Time of Condition F of this LCO are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1

With two CS trains inoperable, the NaOH System and one or both post-accident charcoal filter trains inoperable, three or more CRFC units inoperable, or one CS and two post-accident charcoal filter trains inoperable, the plant is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

The applicable SR descriptions from Bases 3.5.2 apply. This SR is required since the OPERABILITY of valves 896A and 896B is also required for the CS System.

SR 3.6.6.2

Verifying the correct alignment for manual, power operated, and automatic valves in the CS flow path provides assurance that the proper flow paths will exist for CS System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment (there are no valves inside containment) and capable of potentially being mispositioned are in the correct position.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.3

Verifying the correct alignment for manual, power operated, and automatic valves in the NaOH System flow path provides assurance that the proper flow paths will exist for NaOH System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment (there are no valves inside containment) and capable of potentially being mispositioned are in the correct position.

SR 3.6.6.4

Operating each CRFC unit for ≥ 15 minutes once every 31 days ensures that all CRFC units are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The 31 day Frequency was developed considering the known reliability of the fan units and controls, the redundancy available, and the low probability of significant degradation of the CRFC units occurring between surveillances. It has also been shown to be acceptable through operating experience.

SR 3.6.6.5

Verifying cooling water (i.e., SW) flow to each CRFC unit provides assurance that the energy removal capability of the CRFC assumed in the accident analyses will be achieved (Ref. 11). The minimum and maximum SW flows are not required to be specifically determined by this SR due to the potential for a containment air temperature transient. Instead, this SR verifies that SW flow is available to each CRFC unit. The 31 day Frequency was developed considering the known reliability of the SW System, the two CRFC train redundancy available, and the low probability of a significant degradation of flow occurring between surveillances.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.6

Operating each post-accident charcoal filter train for ≥ 15 minutes once every 31 days ensures that all trains are OPERABLE and that all dampers are functioning properly. It also ensures that blockage can be detected for corrective action. The 31 day Frequency was developed considering the known reliability of the post-accident charcoal filter trains, the redundancy available, and the low probability of significant degradation of the train occurring between surveillances. It has also been shown to be acceptable through operating experience.

SR 3.6.6.7

Verifying each CS pump's developed head at the flow test point is greater than or equal to the required developed head ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by Section XI of the ASME Code (Ref. 12). Since the CS pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice testing confirms component OPERABILITY, trends performance, and detects incipient failures by abnormal performance. The Frequency of the SR is in accordance with the Inservice Testing Program.

SR 3.6.6.8

To provide effective iodine removal, the containment spray must be an alkaline solution. Since the RWST contents are normally acidic, the spray additive tank must provide a sufficient volume of spray additive to adjust pH for all water that is injected. This SR is performed to verify the availability of sufficient NaOH solution in the spray additive tank. The 184 day Frequency was developed based on the low probability of an undetected change in tank volume occurring during the SR interval since the tank is normally isolated. Tank level is also indicated and alarmed in the control room, so that there is high confidence that a substantial change in level would be detected.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.9

This SR provides verification of the NaOH concentration in the spray additive tank and is sufficient to ensure that the spray solution being injected into containment is at the correct pH level. The 184 day Frequency is sufficient to ensure that the concentration level of NaOH in the spray additive tank remains within the established limits. This is based on the low likelihood of an uncontrolled change in concentration since the tank is normally isolated and the probability that any substantial variance in tank volume will be detected.

SR 3.6.6.10

This SR verifies that the required post-accident charcoal filter train testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing charcoal adsorber efficiency, minimum system flowrate, and the physical properties of the activated charcoal. The minimum required flowrate through each of the two post-accident charcoal filters is 33,000 cubic feet per minute at accident conditions (or 38,500 cubic feet per minute at normal operating conditions). Specific test frequencies and additional information are discussed in detail in the VFTP. However, the maximum surveillance interval for refueling outage tests is based on 24 month refueling cycles and not 18 month cycles as defined by Regulatory Guide 1.52 (Ref. 13).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.11

This SR verifies that the required CRFC unit testing is performed in accordance with the VFTP. The VFTP includes testing HEPA filter performance. The minimum required flow rate through each of the four CRFC units is 33,000 cubic feet per minute at accident conditions (or 38,500 cubic feet per minute at normal operating conditions). Specific test frequencies and additional information are discussed in detail in the VFTP. However, the maximum surveillance interval for refueling outage tests is based on 24 month refueling cycles and not 18 month cycles as defined by Regulatory Guide 1.52 (Ref. 13).

SR 3.6.6.12 and SR 3.6.6.13

These SRs require verification that each automatic CS valve in the flowpath (860A, 860B, 860C, and 860D) actuates to its correct position and that each CS pump starts upon receipt of an actual or simulated actuation of a containment High pressure signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillances were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillances when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.6.14

This SR requires verification that each CRFC unit actuates upon receipt of an actual or simulated safety injection signal. The 24 month Frequency is based on engineering judgment and has been shown to be acceptable through operating experience. See SR 3.6.6.12 and SR 3.6.6.13, above, for further discussion of the basis for the 24 month Frequency.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.15

This SR requires verification every 24 months that each train of post-accident charcoal filters actuates upon receipt of an actual or simulated safety injection signal. The 24 month frequency is based on engineering judgement and has been shown to be acceptable through operating experience. See SR 3.6.6.12 and SR 3.6.6.13, above, for further discussion of the basis for the 24 month Frequency.

SR 3.6.6.16

This SR provides verification that each automatic valve in the NaOH System flow path that is not locked, sealed, or otherwise secured in position (836A and 836B) actuates to its correct position upon receipt of an actual or simulated actuation of a containment Hi-Hi pressure signal. The 24 month frequency is based on engineering judgement and has been shown to be acceptable through operating experience. See SR 3.6.6.12 and SR 3.6.6.13, above, for further discussion of the basis for the 24 month Frequency.

SR 3.6.6.17

To ensure that the correct pH level is established in the borated water solution provided by the CS System, flow through the eductor is verified once every 5 years. This SR in conjunction with SR 3.6.6.16 provides assurance that NaOH will be added into the flow path upon CS initiation. A minimum flow of 20 gpm through the eductor must be established as assumed in the accident analyses. A flow path must also be verified from the NaOH tank to the eductors. Due to the passive nature of the spray additive flow controls, the 5 year Frequency is sufficient to identify component degradation that may affect flow injection.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.18

With the CS inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through test connections. This SR ensures that each spray nozzle is unobstructed and provides assurance that spray coverage of the containment during an accident is not degraded. Due to the passive design of the nozzle, a test at 10 year intervals is considered adequate to detect obstruction of the nozzles.

REFERENCES

1. Atomic Industry Forum (AIF) GDC 49, 52, 58, 59, 60, and 61, issued for comment July 10, 1967.
2. Branch Technical Position MTEB 6-1, "pH For Emergency Coolant Water For PWRs."
3. Letter from D. M. Crutchfield, NRC, to J. E. Maier, RG&E, Subject: "SEP Topic VI-7.B: ESF Automatic Switchover from Injection to Recirculation Mode, Automatic ECCS Realignment, Ginna," dated December 31, 1981.
4. NUREG-0821.
5. UFSAR, Section 6.3.
6. UFSAR, Section 6.1.2.4.
7. 10 CFR 50, Appendix K.
8. UFSAR, Section 6.2.1.2.
9. UFSAR, Section 6.2.2.2.
10. UFSAR, Section 6.5.
11. UFSAR, Section 6.2.2.1.
12. ASME, Boiler and Pressure Vessel Code, Section XI.
13. Regulatory Guide 1.52, Revision 2.

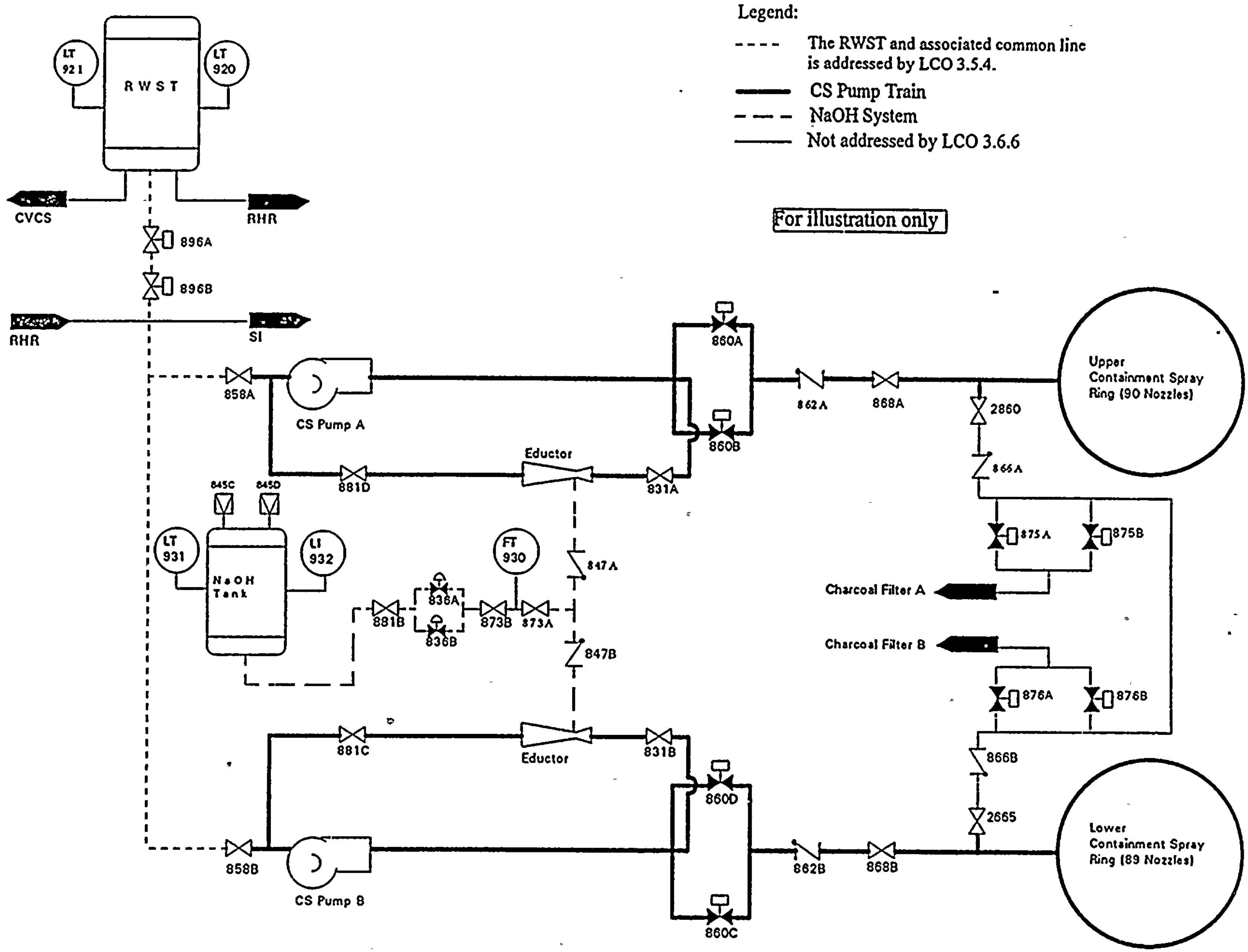
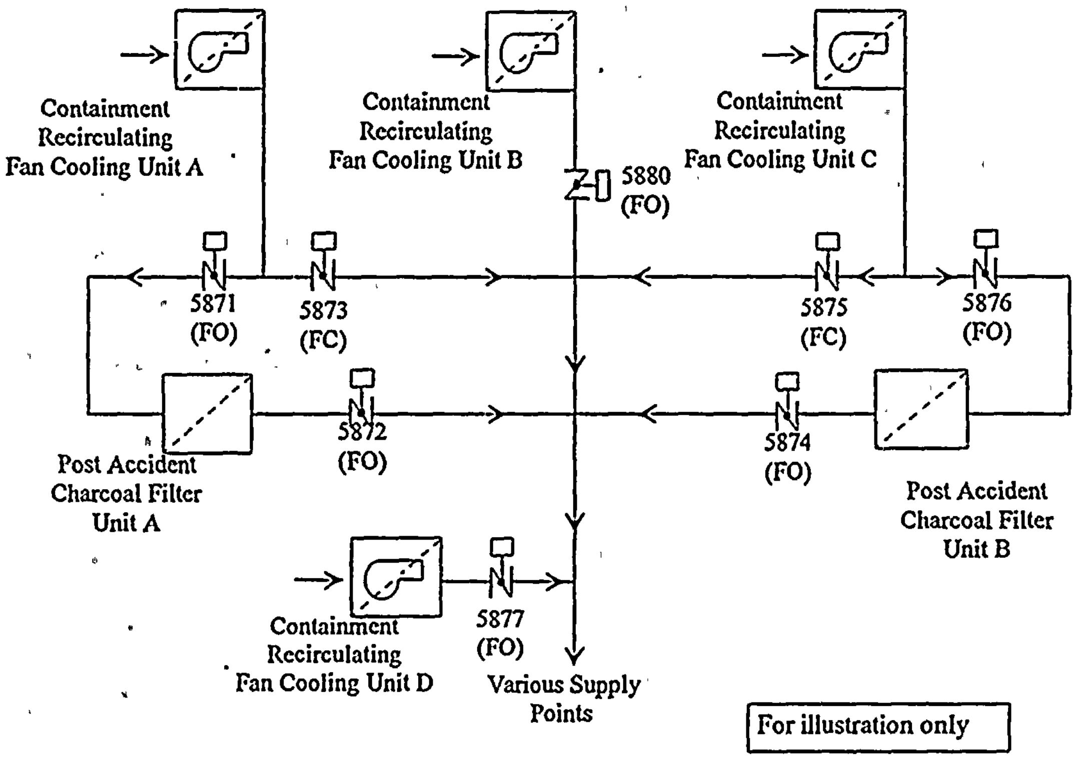


Figure B 3.6.6-1
Containment Spray and NaOH Systems



Notes:

1. Dampers 5871 and 5872 are associated with Post Accident Charcoal Filter Unit A
2. Dampers 5874 and 5876 are associated with Post Accident Charcoal Filter Unit B
3. Damper 5873 is assoicated with both CRFC Unit A and Post Accident Charcoal Filter Unit A
4. Damper 5876 is associated with both CRFC Unit C and Post Accident Charcoal Filter Unit B

Figure B 3.6.6-2
CRFC and Containment Post-Accident Charcoal Systems

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Hydrogen Recombiners

BASES

BACKGROUND

The function of the hydrogen recombiners is to eliminate the potential breach of containment due to a hydrogen oxygen reaction.

Per 10 CFR 50.44, "Standards for Combustible Gas Control Systems in Light-Water-Cooled Reactors" (Ref. 1), hydrogen recombiners are required to reduce the hydrogen concentration in the containment following a loss of coolant accident (LOCA) or steam line break (SLB). The recombiners accomplish this by collecting the hydrogen and oxygen atmospheric mixture inside containment and oxidizing the hydrogen in a combustion chamber. Additional hydrogen is added by the recombiner to ensure that the noncondensible combustion products that could cause a progressive rise in containment pressure are avoided. Oxygen is also added to prevent depletion of oxygen below the concentration required for stable operation of the combuster. The product of combustion, water vapor, is cooled and condensed from the atmosphere by the Containment Recirculation Fan Cooler System. The hydrogen recombiners are manually initiated since flammable limits would not be reached until several days after a Design Basis Accident (DBA). Prevention of hydrogen accumulation during normal operation is accomplished by use of the Mini-Purge System.

(continued)

BASES

BACKGROUND (continued)

Two 100% capacity independent hydrogen recombiner systems are provided. Each consists of controls located in the Intermediate Building, a power supply from a separate Engineered Safety Features bus, and a recombiner. The recombiners are comprised of a blower fan to circulate containment air to the combuster, a combuster chamber with a main burner, two igniters (includes an installed spare), a pilot burner, and a dilution chamber downstream of the flame zone where products of the combustion are mixed with containment air to reduce the temperature of the gas leaving the system. A single recombiner is capable of maintaining the hydrogen concentration in containment at approximately 2.0 volume percent (v/o) which is below the 4.1 v/o flammability limit. Two recombiners are provided to meet the requirement for redundancy and independence.

APPLICABLE SAFETY ANALYSES

The hydrogen recombiners provide for the capability of controlling the bulk hydrogen concentration in containment to less than the lower flammable concentration of 4.1 v/o following a DBA. This control prevents a containment wide hydrogen burn, thus ensuring the pressure and temperature inside containment as assumed in the analyses are not exceeded. The limiting DBA relative to hydrogen generation is a LOCA.

Hydrogen may accumulate in containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant;

b. Radiolytic decomposition of water in the Reactor Coolant System (RCS) and the containment sump;

c. Hydrogen in the RCS at the time of the LOCA (i.e., hydrogen dissolved in the reactor coolant and hydrogen gas in the pressurizer vapor space); or

d. Corrosion of metals exposed to containment spray and Emergency Core Cooling System solutions.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

To evaluate the potential for hydrogen accumulation in containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 2 are used to maximize the amount of hydrogen calculated.

The minimum hydrogen flammability limit is 4.1 v/o, however, to avoid a dynamic overpressurization of containment, all hydrogen must be ignited before a concentration of 6.0 v/o is reached (Ref. 3). An alternative to the ignition of hydrogen at concentrations ≥ 6.0 v/o is venting of containment using the Mini-Purge System. However, venting would most likely require evacuations of the general public within a radius of several miles surrounding the plant.

Based on the conservative assumptions used to calculate the hydrogen concentration versus time after a LOCA, the hydrogen concentration in the primary containment would reach 5.5 v/o about 31 days after the LOCA if no recombiner was functioning (Ref. 3). However, a more realistic model predicts that a hydrogen concentration of 4.1 v/o (the lower flammability limit) will be reached in 31 days. Operation of the hydrogen recombiners ensures that a concentration of 6.0 v/o would not be reached inside containment which could result in an overpressurization given an ignition source.

The hydrogen recombiners are designed such that, with the conservatively calculated hydrogen generation rates discussed above, a single recombiner is capable of limiting the peak hydrogen concentration in containment to less than 4.1 v/o (Ref. 3).

The hydrogen recombiners satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

Two hydrogen recombiners must be OPERABLE and capable of being placed into operation before the minimum hydrogen flammability limit of 4.1 v/o is reached following a DBA. This ensures operation of at least one hydrogen recombiner in the event of a worst case single active failure. The necessary hydrogen or oxygen required to operate the hydrogen recombiner does not have to be available onsite for the hydrogen recombiner to be considered OPERABLE.

Operation with at least one hydrogen recombiner ensures that the post-LOCA hydrogen concentration can be prevented from exceeding the flammability limit or causing an overpressurization of containment given a hydrogen ignition source.

APPLICABILITY

In MODES 1 and 2, two hydrogen recombiners are required to control the hydrogen concentration within containment below its flammability limit of 4.1 v/o following a LOCA, assuming a worst case single failure.

In MODES 3 and 4, both the hydrogen production rate and the total hydrogen produced after a LOCA or SLB would be less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the hydrogen recombiners is low. Therefore, the hydrogen recombiners are not required in MODE 3 or 4.

In MODES 5 and 6, the probability and consequences of a DBA are low, due to the pressure and temperature limitations in these MODES. Therefore, hydrogen recombiners are not required in these MODES.

(continued)

BASES (continued)

ACTIONS

A.1

With one containment hydrogen recombiner inoperable, the inoperable recombiner must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE hydrogen recombiner is adequate to perform the hydrogen control function. However, the overall reliability is reduced because a single failure in the OPERABLE recombiner could result in reduced hydrogen control capability. The 30 day Completion Time is based on the availability of the other hydrogen recombiner, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

Required Action A.1 has been modified by a Note that states the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one recombiner is inoperable. This allowance is based on the availability of the other hydrogen recombiner, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

With two hydrogen recombiners inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by the Mini-Purge System which consists of two isolation valves per penetration flow path that are capable of opening and a supply fan capable of performing purging functions. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. In addition, the alternate hydrogen control system capability must be verified once per 12 hours thereafter to ensure its continued availability. Both the initial verification and all subsequent verifications may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform any Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system (e.g., opening of mini-purge valves). If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen recombiners to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit.

C.1

If the inoperable hydrogen recombiner(s) cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

This SR requires a system functional check of each hydrogen recombiner. A functional check does not require an actual test of the hydrogen recombiner due to the system design which requires oxygen and hydrogen to be pumped into containment. Instead, a functional check is a physical and visual inspection of the hydrogen recombiners to verify that piping is not plugged, the ignitor is OPERABLE, and the recombiners are not fouled. The use of a test gas (e.g., nitrogen) is acceptable. Verification that the recombiners are not fouled requires operation of the blower fan and operation of the system control valves.

The 24 month Frequency for this surveillance was developed considering the incidence of hydrogen recombiners failing the SR in the past is low.

SR 3.6.7.2

This SR requires performance of a CHANNEL CALIBRATION of each hydrogen recombiner actuation and control channel. A CHANNEL CALIBRATION is required to ensure that the hydrogen recombiner will provide the correct hydrogen/oxygen mixture to the combustion chamber.

The 24 month Frequency for this Surveillance was developed considering the incidence of hydrogen recombiners failing the SR in the past is low.

REFERENCES

1. 10 CFR 50.44.
2. Safety Guide 1.7, Rev. 0.
3. UFSAR, Section 6.2.5.

3.7 PLANT SYSTEMS

3.7.1 Main Steam Safety Valves (MSSVs)

LCO 3.7.1 Eight MSSVs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each MSSV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more MSSVs inoperable.	A.1 Restore inoperable MSSV(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	-------------------NOTE------------------- Only required to be performed in MODES 1 and 2. -- Verify each MSSV lift setpoint specified below in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program

VALVE NUMBER		LIFT SETTING
SG A	SG B	(psig +1%, -3%)
3509	3508	1140
3511	3510	1140
3515	3512	1140
3513	3514	1085

3.7 PLANT SYSTEMS

3.7.2 Main Steam Isolation Valves (MSIVs) and Non-Return Check Valves

LCO 3.7.2 Two MSIVs and two non-return check valves shall be OPERABLE.

APPLICABILITY: MODE 1,
MODE 2 and 3 except when all MSIVs are closed and de-activated.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more valves inoperable in flowpath from a steam generator (SG) in MODE 1.	A.1	Restore valve(s) to OPERABLE status.	8 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 2.	6 hours
C. One or more valves inoperable in flowpath from a SG in MODE 2 or 3.	C.1	Close MSIV.	8 hours
	<u>AND</u>		
	C.2	Verify MSIV is closed.	Once per 7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and Associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	6 hours 12 hours
E. One or more valves inoperable in flowpath from each SG.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	Verify closure time of each MSIV is ≤ 5 seconds under no flow and no load conditions.	In accordance with the Inservice Testing Program
SR 3.7.2.2	Verify each main steam non-return check valve can close.	In accordance with the Inservice Testing Program
SR 3.7.2.3	Verify each MSIV can close on an actual or simulated actuation signal.	24 months

3.7 PLANT SYSTEMS

3.7.3 Main Feedwater Regulating Valves (MFRVs), Associated Bypass Valves, and Main Feedwater Pump Discharge Valves (MFPDVs)

LCO 3.7.3 Two MFRVs, associated bypass valves, and two MFPDVs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3 except when both steam generators are isolated from both main feedwater pumps.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more MFPDV(s) inoperable.	A.1 Close MFPDV(s).	24 hours
	<u>AND</u>	
	A.2 Verify MFPDV(s) is closed.	Once per 7 days
B. One or more MFRV(s) inoperable.	B.1 Close or isolate MFRV(s).	24 hours
	<u>AND</u>	
	B.2 Verify MFRV(s) is closed or isolated.	Once per 7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more MFRV bypass valve(s) inoperable.	C.1 Close or isolate MFRV bypass valve(s). AND C.2 Verify MFRV bypass valve(s) is closed or isolated.	24 hours Once per 7 days
D. Required Action and associated Completion Time for Condition A, B, or C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	6 hours 12 hours
E. One or more MFPDV(s) and one or more MFRV(s) inoperable. OR One or more MFPDV(s) and one or more MFRV bypass valve(s) inoperable.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	Verify the closure time of each MFPDV is ≤ 80 seconds on an actual or simulated actuation signal.	In accordance with the Inservice Testing Program
SR 3.7.3.2	Verify the closure time of each MFRV and associated bypass valve is ≤ 10 seconds on an actual or simulated actuation signal.	In accordance with the Inservice Testing Program

3.7 PLANT SYSTEMS

3.7.4 Atmospheric Relief Valves (ARVs)

LCO 3.7.4 Two ARV lines shall be OPERABLE.

APPLICABILITY: MODES 1 and 2,
MODE 3 with Reactor Coolant System average temperature (T_{avg}) $\geq$ 500°F.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One ARV line inoperable.	A.1	--------NOTE--------- LCO 3.0.4 is not applicable. --------------------- Restore ARV line to OPERABLE status.	 7 days
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 3 with T_{avg} < 500°F.	8 hours
C. Two ARV lines inoperable.	C.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Perform a complete cycle of each ARV.	24 months
SR 3.7.4.2	Verify one complete cycle of each ARV block valve.	24 months

3.7 PLANT SYSTEMS

3.7.5 Auxiliary Feedwater (AFW) System

LCO 3.7.5 Two motor driven AFW (MDAFW) trains, one turbine driven AFW (TDAFW) train, and two standby AFW (SAFW) trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One TDAFW train flowpath inoperable.	A.1 Restore TDAFW train flowpath to OPERABLE status.	7 days
B. One MDAFW train inoperable.	B.1 Restore MDAFW train to OPERABLE status.	7 days
C. TDAFW train inoperable. <u>OR</u> Two MDAFW trains inoperable. <u>OR</u> One TDAFW train flowpath and one MDAFW train inoperable to opposite steam generators (SGs).	C.1 Restore one MDAFW train or TDAFW train flowpath to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. All AFW trains to one or more SGs inoperable.	D.1	Restore one AFW train or TDAFW flowpath to each affected SG to OPERABLE status.	4 hours
E. One SAFW train inoperable.	E.1	Restore SAFW train to OPERABLE status.	14 days
F. Both SAFW trains inoperable.	F.1	Restore one SAFW train to OPERABLE status.	7 days
G. Required Action and associated Completion Time for Condition A, B, C, D, E, or F not met.	G.1	Be in MODE 3.	6 hours
	AND		
	G.2	Be in MODE 4.	12 hours
H. Three AFW trains and both SAFW trains inoperable.	H.1	---------NOTE-------- LCO 3.0.3 and all other LCO Required Actions requiring MODE changes are suspended until one MDAFW, TDAFW, or SAFW train is restored to OPERABLE status. --------------------	
		Initiate action to restore one MDAFW, TDAFW, or SAFW train to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.7.5.1	Verify each AFW and SAFW manual, power operated, and automatic valve in each water flow path, and in both steam supply flow paths to the turbine driven pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.5.2	------------------NOTE-------------------- Required to be met prior to entering MODE 1 for the TDAFW pump. -- Verify the developed head of each AFW pump at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.7.5.3	Verify the developed head of each SAFW pump at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.7.5.4	Perform a complete cycle of each AFW and SAFW motor operated suction valve from the Service Water System, each AFW and SAFW discharge motor operated isolation valve, and each SAFW cross-tie motor operated valve.	In accordance with the Inservice Testing Program
SR 3.7.5.5	Verify each AFW automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.5.6	------------------NOTE------------------ Required to be met prior to entering MODE 1 for the TDAFW pump. -- Verify each AFW pump starts automatically on an actual or simulated actuation signal.	24 months
SR 3.7.5.7	Verify each SAFW train can be actuated and controlled from the control room.	24 months

3.7 PLANT SYSTEMS

3.7.6 Condensate Storage Tanks (CSTs)

LCO 3.7.6 The CSTs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. CST water volume not within limit.	A.1 Verify by administrative means OPERABILITY of backup water supply.	4 hours
	<u>AND</u>	
	A.2 Restore CST water volume to within limit.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	B.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.7.6.1 Verify the CST water volume is $\geq$ 22,500 gal.	12 hours

3.7 PLANT SYSTEMS

3.7.7 Component Cooling Water (CCW) System

LCO 3.7.7 Two CCW trains, two CCW heat exchangers, and the CCW loop header shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CCW train inoperable.	A.1 Restore CCW train to OPERABLE status.	72 hours
B. One CCW heat exchanger inoperable.	B.1 Restore CCW heat exchanger to OPERABLE status.	31 days
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two CCW trains, two CCW heat exchangers, or loop header inoperable.	------------NOTE------------ LCO 3.0.3 and all other LCO Required Actions requiring MODE changes are suspended until one CCW train, one CCW heat exchanger, and the loop header are restored to OPERABLE status. ----------------------------	
	D.1 Initiate Action to restore one CCW train, one heat exchanger, and loop header to OPERABLE status.	Immediately
	<u>AND</u>	
	D.2 Be in MODE 3.	6 hours
	<u>AND</u>	
	D.3 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	-------------------NOTE------------------- Isolation of CCW flow to individual components does not render the CCW loop header inoperable. -- Verify each CCW manual and power operated valve in the CCW train and heat exchanger flow path and loop header that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.7.2	Perform a complete cycle of each motor operated isolation valve to the residual heat removal heat exchangers.	In accordance with the Inservice Testing Program

3.7 PLANT SYSTEMS

3.7.8 Service Water (SW) System

LCO 3.7.8 Two SW trains and the SW loop header shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One SW train inoperable.	A.1	Restore SW train to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours
C. Two SW trains or loop header inoperable.	C.1	--------NOTE---------- Enter applicable conditions and Required Actions of LCO 3.7.7, "CCW System," for the component cooling water heat exchanger(s) made inoperable by SW. ---------------------	
		Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.8.1	Verify screenhouse bay water level and temperature are within limits.	24 hours
SR 3.7.8.2	-------------------NOTE------------------- Isolation of SW flow to individual components does not render the SW loop header inoperable. -- Verify each SW manual, power operated, and automatic valve in the SW train flow path and loop header that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.8.3	Verify all SW loop header cross-tie valves are locked in the correct position.	31 days
SR 3.7.8.4	Verify each SW automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.7.8.5	Verify each SW pump starts automatically on an actual or simulated actuation signal.	24 months

3.7 PLANT SYSTEMS

3.7.9 Control Room Emergency Air Treatment System (CREATS)

LCO 3.7.9 The CREATS shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, 4, 5, and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. CREATS filtration train inoperable.	A.1 Restore CREATS filtration train to OPERABLE status. OR A.2 ---------NOTE-------- The control room may be unisolated for ≤ 1 hour every 24 hours while in this condition. --------------------- Place isolation dampers in CREATS Mode F.	48 hours 48 hours
B. --------NOTE--------- Separate Condition entry allowed for each damper. --------------------- One CREATS isolation damper in one or more outside air flowpaths inoperable.	B.1 Restore isolation damper to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, 3, or 4.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 5.	36 hours
D. Required Action and associated Completion Time of Condition A or B not met in MODE 5 or 6 or during movement of irradiated fuel.	D.1	Place OPERABLE isolation damper(s) in CREATS Mode F.	Immediately
	OR		
	D.2.1	Suspend CORE ALTERATIONS.	Immediately
		AND	
	D.2.2	Suspend movement of irradiated fuel assemblies.	Immediately
E. Two CREATS isolation dampers for one or more outside air flow paths inoperable in MODE 1, 2, 3, or 4.	E.1	Enter LCO 3.0.3.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. Two CREATS isolation dampers for one or more outside air flow paths inoperable in MODE 5 or 6 or during movement of irradiated fuel assemblies.	F.1	Initiate actions to restore one isolation damper to OPERABLE status.	Immediately
	AND		
	F.2	Suspend CORE ALTERATIONS.	Immediately
	AND		
	F.3	Suspend movement of irradiated fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.9.1	Operate the CREATS filtration train ≥ 15 minutes.	31 days
SR 3.7.9.2	Perform required CREATS filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with VFTP
SR 3.7.9.3	Verify the CREATS actuates on an actual or simulated actuation signal.	24 months

3.7 PLANT SYSTEMS

3.7.10 Auxiliary Building Ventilation System (ABVS)

LCO 3.7.10 The ABVS shall be OPERABLE and in operation.

APPLICABILITY: During movement of irradiated fuel assemblies in the Auxiliary Building when one or more fuel assemblies in the Auxiliary Building has decayed < 60 days since being irradiated.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ABVS inoperable.	A.1 -------NOTE-------- LCO 3.0.3 is not applicable. ------------------- Suspend movement of irradiated fuel assemblies in the Auxiliary Building.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.7.10.1 Verify ABVS is in operation.	24 hours
SR 3.7.10.2 Verify ABVS maintains a negative pressure with respect to the outside environment at the Auxiliary Building operating floor level.	24 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.10.3	Perform required Spent Fuel Pool Charcoal Adsorber System filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP

3.7 PLANT SYSTEMS

3.7.11 Spent Fuel Pool (SFP) Water Level

LCO 3.7.11 The SFP water level shall be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: During movement of irradiated fuel assemblies in the SFP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SFP water level not within limit.	A.1 --------NOTE--------- LCO 3.0.3 is not applicable. --------------------- Suspend movement of irradiated fuel assemblies in the SFP.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.11.1	Verify the SFP water level is ≥ 23 ft above the top of the irradiated fuel assemblies seated in the storage racks.	7 days

3.7 PLANT SYSTEMS

3.7.12 Spent Fuel Pool (SFP) Boron Concentration

LCO 3.7.12 The SFP boron concentration shall be ≥ 300 ppm.

APPLICABILITY: When fuel assemblies are stored in the SFP and a SFP verification has not been performed since the last movement of fuel assemblies in the SFP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SFP boron concentration not within limit.	------------NOTE------------- LCO 3.0.3 is not applicable. ----------------------------	
	A.1 Suspend movement of fuel assemblies in the SFP.	Immediately
	AND	
	A.2.1 Initiate action to restore SFP boron concentration to within limit.	Immediately
	OR	
	A.2.2 Initiate action to perform SFP verification.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.12.1	Verify the SFP pool boron concentration is within limit.	31 days

3.7 PLANT SYSTEMS

3.7.13 Spent Fuel Pool (SFP) Storage

LCO 3.7.13 Fuel assembly storage in the spent fuel pool shall be maintained as follows:

a. Fuel assemblies in Region 1 shall have a K-infinity of ≤ 1.458; and

b. Fuel assemblies in Region 2 shall have initial enrichment and burnup within the acceptable area of the Figure 3.7.13-1.

APPLICABILITY: Whenever any fuel assembly is stored in the spent fuel pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met for either region.	A.1 --------NOTE--------- LCO 3.0.3 is not applicable. --------------------- Initiate action to move the noncomplying fuel assembly from the applicable region.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.13.1	------------------NOTE------------------ Not required to be performed when transferring a fuel assembly from Region 2 to Region 1. -- Verify by administrative means the K-infinity of the fuel assembly is $\leq$ 1.458.	Prior to storing the fuel assembly in Region 1
SR 3.7.13.2	Verify by administrative means the initial enrichment and burnup of the fuel assembly is in accordance with Figure 3.7.13-1.	Prior to storing the fuel assembly in Region 2

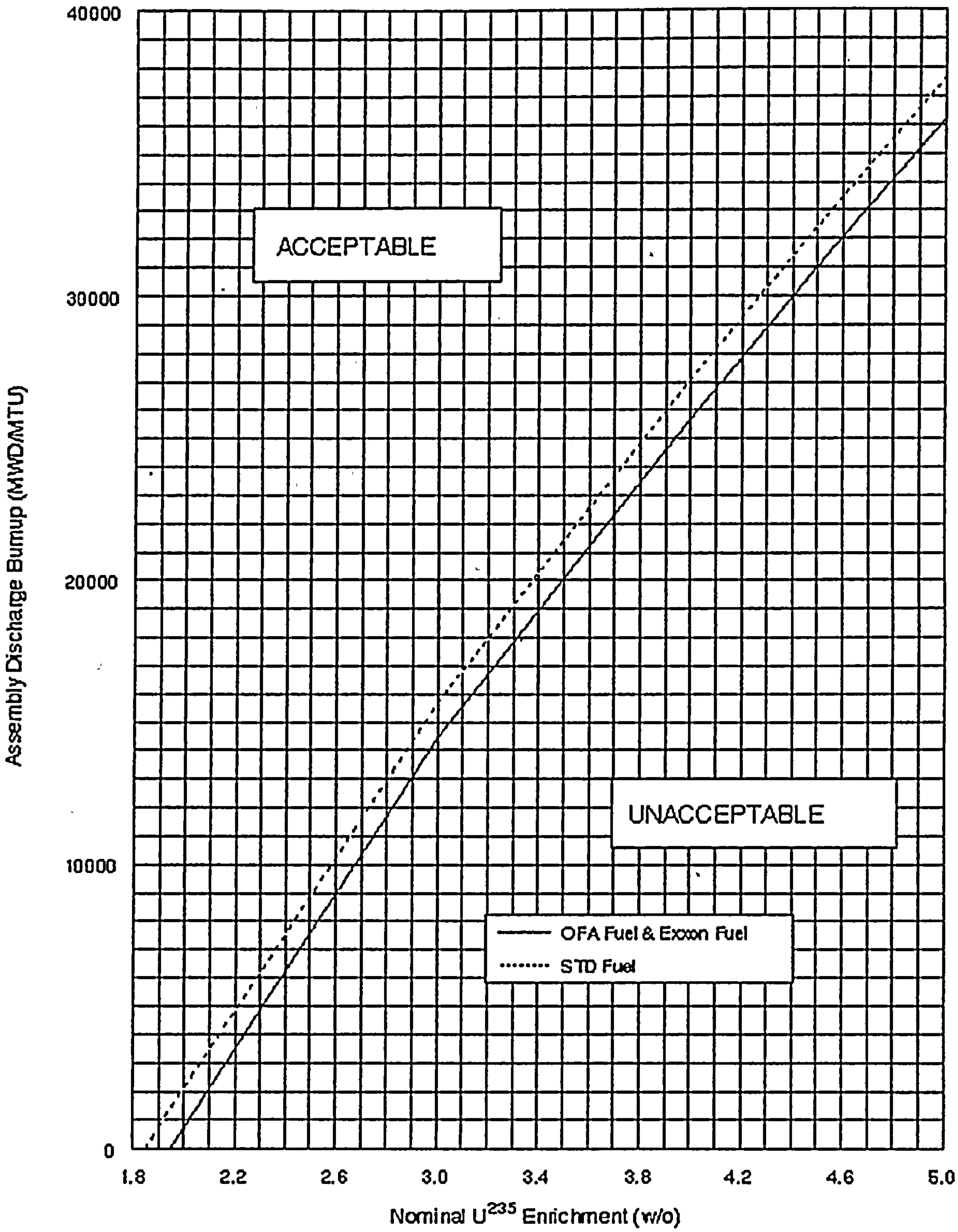


Figure 3.7.13-1
Fuel Assembly Burnup Limits in Region 2

3.7 PLANT SYSTEMS

3.7.14 Secondary Specific Activity

LCO 3.7.14 The specific activity of the secondary coolant shall be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Specific activity not within limit.	A.1 Be in MODE 3. AND A.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.7.14.1 Verify the specific activity of the secondary coolant is ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131.	31 days

B 3.7 PLANT SYSTEMS

B 3.7.1 Main Steam Safety Valves (MSSVs)

BASES

BACKGROUND

The primary purpose of the MSSVs is to provide overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the reactor coolant pressure boundary (RCPB) by providing a heat sink for the removal of energy from the Reactor Coolant System (RCS) if the preferred (but non safety related) heat sink, provided by the condenser and circulating water system, is not available.

Four MSSVs are located on each main steam header, outside containment in the Intermediate Building, upstream of the main steam isolation valves (Ref. 1). MSSVs 3509, 3511, 3513, and 3515 are located on the steam generator (SG) A main steam header while MSSVs 3508, 3510, 3512 and 3514 are located on the SG B main steam header. The MSSVs are designed to limit the secondary system to ≤ 110% of design pressure when passing 100% of design flow. The MSSV design includes staggered setpoints so that only the needed valves will actuate. Staggered setpoints reduce the potential for valve chattering that is due to steam pressure insufficient to fully open all valves following a turbine/reactor trip.

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs is to limit the secondary system pressure to ≤ 110% of design pressure when passing 100% of design steam flow. This design basis is sufficient to cope with any anticipated operational occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis.

The events that challenge the relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased RCS heat removal events (Ref. 2). Of these, the full power loss of external load event is the limiting AOO. This event also results in the loss of normal feedwater flow to the SGs.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The transient response for a loss of external load event without a direct reactor trip (i.e., loss of load when < 50% RTP) presents no hazard to the integrity of the RCS or the Main Steam System. For transients at power levels > 50%, the effect on RCS safety limits is evaluated with no credit taken for the pressure relieving capability of pressurizer spray, the steam dump system, and the SG atmospheric relief valves. The reactor is tripped on high pressurizer pressure with the pressurizer safety valves and MSSVs required to be opened to maintain the RCS and Main Steam System within 110% of their design values.

The MSSVs are assumed to have two active and one passive failure modes. The active failure modes are spurious opening (as an initiating event only), and failure to reclose once opened. The passive failure mode is failure to open upon demand which is not considered in the accident analyses.

The MSSVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

The accident analysis requires four MSSVs per steam generator to provide overpressure protection for design basis transients occurring at 102% RTP. The OPERABILITY of the MSSVs is defined as the ability to open within the setpoint tolerances, relieve SG overpressure, and reseat when pressure has been reduced. The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Testing Program.

The lift settings, according to SR 3.7.1.1 in the accompanying LCO, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB or secondary system.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, four MSSVs per SG are required to be OPERABLE to ensure that the RCS remains within its pressure safety limit and that the secondary system, from the SGs to the main steam isolation valves, is limited to ≤ 110% of design pressure for all DBAs.

In MODES 4 and 5, there are no credible transients requiring the MSSVs. The SGs are not normally used for heat removal in MODES 5 and 6, and thus cannot be overpressurized; there is no requirement for the MSSVs to be OPERABLE in these MODES.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

A.1

With one or more MSSVs inoperable, the assumptions used in the accident analysis for loss of external load may no longer be valid and the safety valve(s) must be restored to OPERABLE status within 4 hours. This Condition specifically addresses the appropriate ACTIONS to be taken in the event that a non-significant discrepancy related to the MSSVs is discovered with the plant operating in MODES 1, 2, or 3. Examples of this type of discrepancy include administrative (e.g., documentation of inspection results) or similar deviations which do not result in a loss of MSSV capability to relieve steam. The 4 hour Completion Time allows a reasonable period of time for correction of administrative only problems or for the plant to contact the NRC to discuss appropriate action. The 4 hour Completion time is based on engineering judgement.

This Condition is not applicable to a situation in which the ability of a MSSV to open or reclose is questionable. In this event, this Condition is no longer applicable and Condition B of this LCO should be entered immediately since no corrective actions can be implemented during MODES 1, 2, and 3.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the MSSV(s) cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME Code, Section XI (Ref. 3), requires that safety and relief valve tests be performed in accordance with ANSI/ASME OM-1-1987 (Ref. 4). According to Reference 4, the following tests are required:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting);

d. Compliance with owner's seat tightness criteria; and

e. Verification of the balancing device integrity on balanced valves.

The ANSI/ASME Standard requires that all valves be tested every 5 years, and a minimum of 20% of the valves be tested every 24 months. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. This SR allows a +1% and -3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1 (continued)

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected to ambient conditions of the valve at operating temperature and pressure.

REFERENCES

1. UFSAR, Section 10.3.2.4.
2. UFSAR, Section 15.2.
3. ASME, Boiler and Pressure Vessel Code, Section XI.
4. ANSI/ASME OM-1-1987.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs) and Non-Return Check Valves

BASES

BACKGROUND

The MSIVs (3516 and 3517) isolate steam flow from the secondary side of the steam generators (SGs) following a Design Basis Accident (DBA). MSIV closure is necessary to isolate a SG affected by a steam generator tube rupture (SGTR) event or a steam line break (SLB) to stop the loss of SG inventory and to protect the integrity of the unaffected SG for decay heat removal. The MSIVs are air operated swing disk check valves that are held open by an air operator against spring pressure. The MSIVs are installed to use steam flow to assist in the closure of the valve (Ref. 1).

A MSIV is located in each main steam line header outside containment in the Intermediate Building. The MSIVs are downstream from the main steam safety valves (MSSVs) and turbine driven auxiliary feedwater (AFW) pump steam supply, to assure the MSSVs prevent overpressure on the secondary side and assure steam is available to the AFW system following MSIV closure. Closing the MSIVs isolates each SG from the other, and isolates the turbine, steam dump system, and other auxiliary steam supplies from the SGs.

The MSIVs close on a main steam isolation signal generated by either high containment pressure, high steam flow coincident with low T_{avg} and safety injection (SI), or high-high steam flow coincident with SI.

The MSIVs are designed to work with non-return check valves (3518 and 3519) located immediately downstream of each MSIV to preclude the blowdown of more than one SG following a SLB. The MSIVs fail closed on loss of control or actuation power and loss of instrument air once the air is bled off from the supply line. The MSIVs may also be actuated manually.

Each MSIV has a normally closed manual MSIV bypass valve.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs and non-return check valves is established by the large SLB (Ref. 2). The SLB is evaluated for two cases, one with respect to reactor core response and the second with respect to containment integrity. The SLB for reactor core response is evaluated assuming initial conditions and single failures which have the highest potential for power peaking or departure from nucleate boiling (DNB). The most limiting single failure for this evaluation is the loss of a safety injection pump which reduces the rate of boron injection into the Reactor Coolant System (RCS) delaying the return to subcriticality. The MSIV on the intact SG for this case is assumed to close to prevent excessive cooldown of the RCS which could result in a lower DNB ratio.

The SLB for containment integrity is evaluated assuming initial conditions and single failures which result in the addition of the largest amount of mass and energy into containment. For this scenario, offsite power is assumed to be available and reactor power is below 100% RTP. With offsite power available, the reactor coolant pumps continue to circulate coolant maximizing the RCS cooldown. At lower power levels, the SG inventory and temperature are at their greatest, which maximizes the analyzed mass and energy release to containment. Due to the non-return check valve on the faulted SG, reverse flow from the steam headers downstream of the MSIV and from the intact SG is prevented from contributing to the energy and mass released inside containment by the SLB. This check valve is a passive device which is not assumed to fail.

SLBs outside of containment can occur in the Intermediate Building and downstream of the MSIVs in the Turbine Building. A SLB in piping > 6 inches diameter in the Intermediate Building is not required to be considered due to an augmented piping inspection program (Ref. 3). For a SLB in the Turbine building, the MSIVs on both SGs must close to isolate the break and terminate the event.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MSIVs are also credited in a SGTR to manually isolate the SG with the ruptured tube. In addition to minimizing the radiological releases, this assists the operator in isolating the RCS flow through the ruptured SG by preventing the SG from continuing to depressurize and creating a higher pressure difference between the secondary system and the primary system.

The MSIVs are also considered in other DBAs such as the feedwater line break in which closure of the MSIV on the intact SG maximizes the effect of the break since the energy removal capability of the intact SG would be reduced with respect to long term heat removal.

In addition to providing isolation of a faulted SG during a SLB, feedwater line break, or a SGTR, the MSIVs also serve as a containment isolation boundary. The MSIVs are the second containment isolation boundary for the main steam line penetrations which use the steam lines and SGs inside containment as the first boundary. The MSIVs do not receive an automatic containment isolation signal since a spurious signal could result in a significant plant transient.

The MSIVs and non-return check valves satisfy Criterion 3 of the NRC Policy Statement.

LCO

This LCO requires that two MSIVs and the non-return check valves in the steam lines be OPERABLE. The MSIVs are considered OPERABLE when their isolation times are within limits and they can close on an isolation actuation signal. A MSIV must also be capable of isolating a SG for containment isolation purposes. The non-return check valves are considered OPERABLE when they are capable of closing.

This LCO provides assurance that the MSIVs and non-return check valves will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 100 (Ref. 4) limits.

(continued)

BASES (continued)

APPLICABILITY

The MSIVs and non-return check valves must be OPERABLE in MODES 1, 2, and 3 when there is significant mass and energy in the RCS and SGs to challenge the integrity of containment, or allow a transient to approach DNBR limits. When the MSIVs are closed and de-activated in MODES 2 and 3, they are already performing their safety function and the MSIVs and their associated non-return check valves are not required to be OPERABLE per this LCO.

In MODE 4, the MSIVs and non-return check valves are normally closed, and the RCS and SG energy is low.

In MODE 5 or 6, the SGs do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs and non-return check valves are not required for isolation of potential main steam pipe breaks in these MODES.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each valve.

A.1

With one or more valves inoperable in flow path from a SG in MODE 1, action must be taken to restore OPERABLE status within 8 hours. Some repairs to these valves can be made with the plant under hot conditions. The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs and non-return check valves and the ability to isolate the affected SG by turbine stop valves.

The 8 hour Completion Time is greater than that normally allowed for containment isolation boundaries because the MSIVs are valves that isolate a closed system penetrating containment. These valves differ from most other containment isolation boundaries in that the closed system provides an additional means for containment isolation. Failure of this closed system can only result from a SGTR which is not postulated to occur with any other DBA (e.g., LOCA).

(continued)

BASES

ACTIONS (continued)

B.1

If the MSIV and/or non-return check valve from a SG cannot be restored to OPERABLE status within 8 hours, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in MODE 2 within 6 hours and Condition C would be entered. The Completion Time is reasonable, based on operating experience, to reach MODE 2 in an orderly manner without challenging plant systems.

C.1 and C.2

Since the MSIVs and non-return check valve are required to be OPERABLE in MODES 2 and 3, the inoperable valve(s) may either be restored to OPERABLE status or the associated MSIV closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis and the non-return check valve is no longer required.

The 8 hour Completion Time is consistent with that allowed in Condition A.

For inoperable valves that cannot be restored to OPERABLE status within the specified Completion Time, but the associated MSIV is closed, the MSIV must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgement, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the MSIVs and/or non-return check valve cannot be restored to OPERABLE status or the associated MSIV is not closed within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from MODE 2 conditions in an orderly manner without challenging plant systems.

E.1

If one or more valves in the flow path from each SG are inoperable, the plant is in a condition outside of the accident analyses; therefore, LCO 3.0.3 must be entered immediately. This Condition must be entered when any combination of MSIVs and non-return check valves are inoperable such that at least one valve is inoperable in each of the two main steam flow paths.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is ≤ 5 seconds under no flow and no load conditions. The MSIVs are swing-disk check valves that are held open by their air operators against spring pressure. Once the MSIVs begin to close during hot conditions, the steam flow will assist the valve closure such that testing under no flow and no load conditions is conservative. The 5 second closure time is consistent with the expected response time for instrumentation associated with the MSIV and the accident analysis assumptions.

As the MSIVs are not tested at power, they are exempt from the ASME Code, Section XI (Ref. 5), requirements during operation in MODE 1, 2, or 3. The Frequency is in accordance with the Inservice Testing Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.2

This SR verifies that each main steam non-return check valve can close. As the non-return check valves are not tested at power, they are exempt from the ASME Code, Section XI (Ref. 5), requirements during operation in MODE 1, 2, or 3. The Frequency is in accordance with the Inservice Testing Program.

SR 3.7.2.3

This SR verifies that each MSIV can close on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage. The MSIVs should not be tested at power, since even a partial stroke exercise increases the risk of a valve closure and plant transient when the plant is above MODE 4. As the MSIVs are not tested at power, they are exempt from the ASME Code, Section XI (Ref. 5), requirements during operation in MODES 1, 2 and 3.

The frequency of MSIV testing is every 24 months. The 24 month Frequency for testing is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 5.4.4.
2. UFSAR, Section 15.1.5.
3. UFSAR, Section 3.6.2.5.1.
4. 10 CFR 100.11.
5. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Regulating Valves (MFRVs), Associated Bypass Valves, and Main Feedwater Pump Discharge Valves (MFPDVs)

BASES

BACKGROUND

The MFRVs (4269 and 4270) and their associated bypass valves (4271 and 4272), and MFPDVs (3977 and 3976) isolate main feedwater (MFW) flow to the secondary side of the steam generators (SGs) following a Design Basis Accident (DBA). The safety related function of the MFRVs, associated bypass valves, and MFPDVs is to provide for isolation of MFW flow to the secondary side of the SGs terminating the DBA for line breaks occurring downstream of the valves. Closure effectively terminates the addition of feedwater to an affected SG, limiting the mass and energy release for steam line breaks (SLBs) or feedwater line breaks (FWLBs) inside containment, and reducing the cooldown effects for SLBs.

The MFRVs, associated bypass valves, and MFPDVs in conjunction with check valves located downstream of the isolation valves also provide a pressure boundary for the controlled addition of auxiliary feedwater (AFW) to the intact SG (see Figure B 3.7.3-1).

One MFPDV is located in the Turbine Building on the discharge line of each MFW pump (Ref. 1). One MFRV and associated bypass valve is located on each MFW line to its respective SG, outside containment in the Turbine Building. The MFRVs, associated bypass valves, and MFPVs are located upstream of the AFW injection point so that AFW may be supplied to the SGs following closure of the MFRVs and bypass valves. The piping volume from these valves to the SGs is accounted for in calculating mass and energy releases, and must be refilled prior to AFW reaching the SG following either an SLB or FWLB.

(continued)

BASES

BACKGROUND (continued)	The MFPDV closes on the opening of the MFW pump breaker which occurs on receipt of a safety injection signal or any other signal which trips the pump breaker. The MFRVs and bypass valves close on receipt of a safety injection signal, a SG high level signal, or on a reactor trip with T_{avg} < 554°F with the associated MFRV in auto. All valves may also be actuated manually. In addition to the MFRVs, associated bypass valves and MFPDVs, a check valve located outside containment for each feedwater line is available. The check valve isolates the feedwater line penetrating containment providing a containment isolation boundary.
APPLICABLE SAFETY ANALYSES	The design basis of the MFRVs, associated bypass valves, and MFPDVs is established by the analyses for the SLB. The SLB is evaluated for two cases, one with respect to reactor core response and the second with respect to containment integrity (Ref. 2). The SLB for reactor core response is evaluated assuming initial conditions and single failures which have the highest potential for power peaking or departure from nucleate boiling (DNB). The most limiting single failure for this evaluation is the loss of a safety injection pump which reduces the rate of boron injection into the Reactor Coolant System (RCS) delaying the return to subcriticality. The MFRV and bypass valve on the intact SG for this case are assumed to close on a safety injection signal to prevent excessive cooldown of the RCS which could result in a lower DNB ratio. The failure of either of these valves is bounded by the eventual coastdown of the MFW pumps, which have their breakers opened by a SI signal, and the MFPDV which close on opening of the MFW pump breakers.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SLB for containment integrity is evaluated assuming initial conditions and single failures which result in the addition of the largest amount of mass and energy into containment. For this scenario, offsite power is assumed to be available and reactor power is below 100% RTP. With offsite power available, the reactor coolant pumps continue to circulate coolant, maximizing the RCS cooldown. At lower power levels, the SG inventory and temperature are at their greatest, which maximizes the analyzed mass and energy release to containment. The MFRV and bypass valve on the faulted SG are assumed to close on a safety injection signal to prevent continued contribution to the energy and mass released inside containment by the SLB. The failure of either of these valves is bounded by the eventual coastdown of the MFW pumps and closure of the MFPDVs.

The MFRVs and bypass valves are also credited for isolation in the feedwater transient analyses (e.g., increase in feedwater flow). These valves close on either a safety injection or high SG level signal depending on the scenario. The valves also must close on a FWLB to limit the amount of additional mass and energy delivered to the SGs and containment.

The failure of the MFRVs to control flow is also considered as an initiating event. This includes consideration of a valve failure coincident with an atmospheric relief valve failure since a single component in the Advanced Digital Feedwater Control System (ADFCS) controls both components (Ref. 3). This combined valve failure accident scenario is evaluated with respect to DNB since a large RCS cooldown is possible with this combination of failures. However, this scenario is bounded by the SLB accident.

The MFRVs, associated bypass valves, and MFPDVs satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

This LCO ensures that the MFRVs, associated bypass valves, and MFPDVs will isolate MFW flow to the SGs, following a FWLB or SLB.

This LCO requires that two MFPDVs, two MFRVs, and two MFRV bypass valves be OPERABLE. The MFRVs, associated bypass valves, and MFPDVs are considered OPERABLE when isolation times are within limits and they can close on an isolation actuation signal.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or FWLB inside containment. It may also result in the introduction of water into the main steam lines for an excess feedwater flow event.

APPLICABILITY

The MFRVs, associated bypass, and MFPDVs valves must be OPERABLE whenever there is significant mass and energy in the RCS and SGs. This ensures that, in the event of a DBA, the accident analysis assumptions are maintained. In MODES 1, 2, and 3, the MFRVs, associated bypass valves, and MFPDVs are required to be OPERABLE to limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment. When the valves are closed and de-activated or isolated by a closed manual valve such that both SGs are isolated from both MFW pumps, they are already performing their safety function and no longer required to be OPERABLE.

In MODE 4, the MFRVs, associated bypass valves, and MFPDVs are normally closed since AFW is providing decay heat removal due to the low SG energy level. In MODE 5 or 6, the SGs do not contain much energy because their temperature is below the boiling point of water; therefore, the MFRVs, associated bypass valves, and MFPDVs are not required for isolation of potential pipe breaks in these MODES.

(continued)

BASES (continued)

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each valve.

A.1 and A.2

With one or more MFPDV(s) inoperable, action must be taken to restore the affected valve to OPERABLE status, or close the inoperable valve within 24 hours. The 24 hour Completion Time takes into account the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 24 hour Completion Time is reasonable, based on operating experience.

An inoperable MFPDV that is closed must be verified on a periodic basis that it remains closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion time is reasonable, based on engineering judgement, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed.

B.1 and B.2

With one or more MFRV(s) inoperable, action must be taken to restore the affected valve to OPERABLE status, or to close or isolate the inoperable valve within 24 hours. The 24 hour Completion Time takes into account the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 24 hour Completion Time is reasonable, based on operating experience.

An inoperable MFRV that is closed must be verified on a periodic basis that it remains closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion time is reasonable, based on engineering judgement, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With one or more MFRV bypass valve(s) inoperable, action must be taken to restore the affected valve to OPERABLE status, or to close or isolate the inoperable valve within 24 hours. The 24 hour Completion Time takes into account the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 24 hour Completion Time is reasonable, based on operating experience.

An inoperable MFRV bypass valve that is closed must be verified on a periodic basis that it remains closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed.

D.1 and D.2

If the MFRV, associated bypass valve, or MFPDV cannot be restored to OPERABLE status or closed within 24 hours or cannot be verified closed once per 31 days, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

E.1

If one or more MFPDV(s) and one or more MFRV(s), or one or more MFPDV(s) and one or more MFRV bypass valve(s) are inoperable, the plant is in a condition outside of the accident analyses; therefore, LCO 3.0.3 must be entered immediately. This Condition must be entered when any combination of MFRVs, associated bypass valves, or MFPDVs are inoperable such that a MFW pump, condensate pump, or condensate booster pump can provide unisolable flow to one or both SGs (see Figure B 3.7.3-1).

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that the closure time of each MFPDV is ≤ 80 seconds from the full open position on an actual or simulated actuation signal (i.e., from opening of MFW pump breakers). The valve closure times are assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the plant to operation following a refueling outage. These valves should not be tested at power since even a partial stroke exercise increases the risk of a valve closure with the plant generating power. As these valves are not tested at power, they are exempt from the ASME Code, Section XI, (Ref. 4) requirements during operation in MODES 1, 2, and 3.

The Frequency for this SR is in accordance with the Inservice Testing Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.3.2

This SR verifies that the closure time of each MFRV and associated bypass valve is ≤ 10 seconds from the full open position on an actual or simulated actuation signal. The valve closure times are assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the plant to operation following a refueling outage. These valves should not be tested at power since even a partial stroke exercise increases the risk of a valve closure with the plant generating power. As these valves are not tested at power, they are exempt from the ASME Code, Section XI (Ref. 4), requirements during operation in MODES 1, 2, and 3.

The Frequency for this SR is in accordance with the Inservice Testing Program.

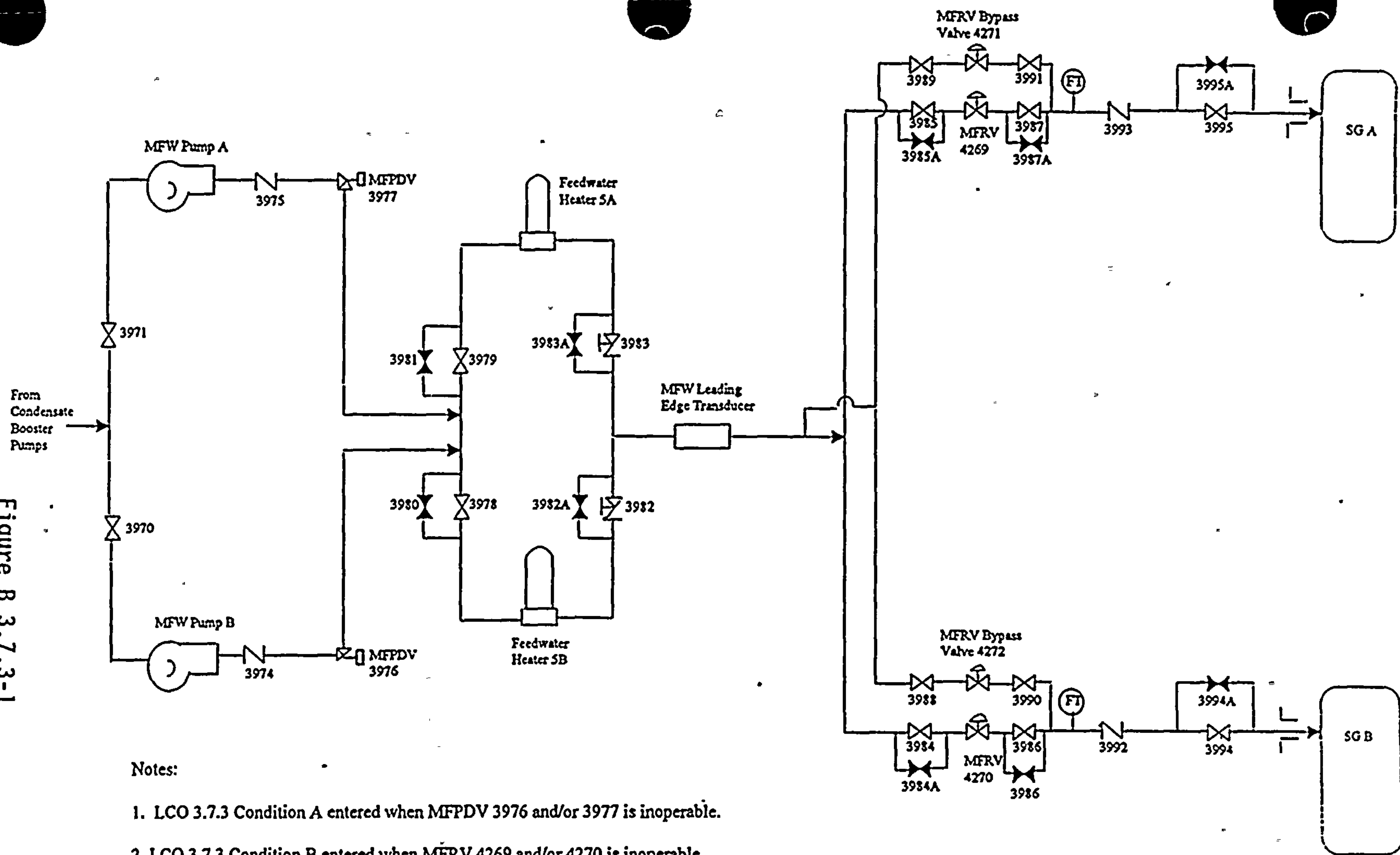
REFERENCES

1. UFSAR, Section 10.4.5.3.

2. UFSAR, Section 15.1.5.

3. UFSAR, Section 15.1.6.

4. ASME, Boiler and Pressure Vessel Code, Section XI.



For illustration only

Notes:

1. LCO 3.7.3 Condition A entered when MFPDV 3976 and/or 3977 is inoperable.
2. LCO 3.7.3 Condition B entered when MFRV 4269 and/or 4270 is inoperable.
3. LCO 3.7.3 Condition C entered when MFRV Bypass Valve 4271 and/or 4272 is inoperable.
4. LCO 3.7.3 Condition E entered when any combination of valve inoperabilities results in an unisolable flowpath from the condensate booster pumps to one or more SGs.

Figure B 3.7.3-1
MFRVs, Associated Bypass Valves and MFPDVs

B 3.7 PLANT SYSTEMS

B 3.7.4 Atmospheric Relief Valves (ARVs)

BASES

BACKGROUND

There is an ARV (3410 and 3411) located on the main steam header from each steam generator (SG). The ARVs are provided with upstream block valves to permit their being tested at power, and to provide an alternate means of isolation. The ARVs have two functions (Ref. 1):

a. provide secondary system overpressure protection below the setpoint of the main steam safety valves (MSSVs); and

b. provide a method for cooling the plant should the preferred heat sink via the steam dump system to the condenser not be available.

The accident analyses do not credit either of these functions since the ARVs do not have a safety-related source of motive air and the accident analyses do not typically require cooldown to the residual heat removal entry conditions since the plant was originally designed to maintain Hot Shutdown conditions indefinitely. The only exception is with respect to steam generator tube rupture (SGTR) events which require the use of at least one ARV to provide heat removal from the Reactor Coolant System (RCS) to prevent saturation conditions from developing.

The ARVs are air operated valves located in the Intermediate Building with a relief capacity of 329,000 lbm/hr each (approximately 5% of RTP). The ARVs are normally closed, fail closed valves which receive motive air from the instrument air system. The valves can also receive motive air from a non-seismic backup nitrogen bottle bank system. The valves are equipped with pneumatic controllers to permit control of the cooldown rate. The ARVs are normally controlled by the Advanced Digital Feedwater Control System (ADFCS) but can also be remote manually operated and opened locally by use of handwheels located on the valves.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The design basis for the ARVs is established by the SGTR event (Ref. 2). For this accident scenario, the operator is required to perform a limited cooldown to establish adequate subcooling as a necessary step to terminate the primary to secondary break flow into the ruptured SG. Following a SGTR, the MSSVs will maintain the secondary system pressure at approximately 1085 psig which could result in the loss of subcooling margin since the RCS average temperature is attempting to stabilize at approximately 547°F. The ARVs are used during the first 30 to 60 minutes of the SGTR to continue the RCS cooldown in an effort to reduce, and eventually terminate, the primary to secondary system flow in the ruptured SG. The inability to cooldown could result in inadequate subcooling margin which would delay the termination of the leakage through the ruptured tube.

The opening of the ARVs is also considered coincident with a failure of a main feedwater regulating valve (Ref. 3) since a single component in the ADFCS controls both components. This combined valve failure accident scenario is evaluated with respect to departure from nucleate boiling since a large RCS cooldown is possible with this combination of failures. However, this scenario is bounded by the steam line break accident.

The ARVs are equipped with block valves in the event the ARV spuriously fails to open or fails to close during use.

The ARVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

Two ARVs and their associated manual block valves are required to be OPERABLE. The ARVs are required for manual operation either locally (using the handwheel or local panel) or remotely to relieve main steam pressure. The ARV block valves must be OPERABLE to isolate a failed open ARV. A closed block valve does not render it or its ARV line inoperable if operator action time to open the block valve can be accomplished within the time frames specified below. Failure to meet the LCO can result in the inability to cool the plant following a SGTR event in which the condenser is unavailable for use with the steam dump system.

(continued)

BASES

LCO (continued)

An ARV line is considered OPERABLE when it is capable of being manually opened within 20 minutes of determining the need to utilize the ARV following a SGTR. The ARV line must also be capable of closing within 15 minutes in the event the ARV spuriously opens on the SG with the ruptured tube. Finally, the ARV line must be capable of closing within 5 minutes in the event that the ARV on the intact SG fails to close following initiation of a cooldown. For the closure requirements, either the ARV or its associated block valve may be credited for OPERABILITY.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS average temperature ≥ 500°F, the ARV lines are required to be OPERABLE.

In MODE 3 with RCS average temperature < 500°F, and in MODE 4, the ARVs are not required since the saturation pressure of the reactor coolant is below the lift settings of the MSSVs. In MODE 5 or 6, an SGTR is not a credible event since the water in the SGs is below the boiling point and RCS pressure is low.

ACTIONS

A.1

With one ARV line inoperable, action must be taken to restore the valve to OPERABLE status within 7 days. The 7 day Completion Time allows for the redundant capability afforded by the remaining OPERABLE ARV line and a nonsafety grade backup in the steam dump system.

Required Action A.1 is modified by a Note indicating that LCO 3.0.4 does not apply since the steam dump system would normally be in service during lower MODES of operation and can provide an acceptable alternative to the inoperable ARV line.

(continued)

BASES

ACTIONS (continued)

B.1

If the ARV line cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 with RCS average temperature < 500°F within 8 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1

If both ARV lines are inoperable, the plant is in a condition outside of the accident analyses for a SGTR event; therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a cooldown of the RCS, the ARVs must be able to be opened either remotely or locally. This SR ensures that the ARVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing or use of an ARV during a plant cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. The Frequency is acceptable from a reliability standpoint.

SR 3.7.4.2

The function of the block valve is to isolate a failed open ARV. Cycling the block valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the block valve during plant cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. The Frequency is acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 10.3.2.5.
2. UFSAR, Section 15.6.3.
3. UFSAR, Section 15.1.6.

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System supplies feedwater to the steam generators (SGs) to remove decay heat from the Reactor Coolant System (RCS) upon the loss of normal feedwater supply. The SGs function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the SGs via the main steam safety valves (MSSVs) or atmospheric relief valves. If the main condenser is available, steam may be released via the steam dump valves. The AFW System is comprised of two separate systems, a preferred AFW System and a Standby AFW (SAFW) System (Ref. 1).

AFW System

The preferred AFW System consists of two motor driven AFW (MDAFW) pumps and one turbine driven AFW (TDAFW) pump configured into three separate trains which are all located in the Intermediate Building (see Figure B 3.7.5-1). Each MDAFW train provides 100% of AFW flow capacity, and the TDAFW pump provides 200% of the required capacity to the SGs, as assumed in the accident analysis. The pumps are equipped with independent recirculation lines to the condensate storage tanks (CSTs). Each MDAFW train is powered from an independent Class 1E power supply and feeds one SG, although each pump has the capability to be realigned from the control room to feed the other SG via cross-tie lines containing normally closed motor operated valves (4000A and 4000B). The two MDAFW trains will actuate automatically on a low-low level signal in either SG, opening of the main feedwater (MFW) pump breakers, a safety injection (SI) signal, or the ATWS mitigation system actuation circuitry (AMSAC). The pumps can also be manually started from the control room.

(continued)

BASES

BACKGROUND (continued)

The TDAFW pump receives steam from each main steam line upstream of the two main steam isolation valves. Either of the steam lines will supply 100% of the requirements of the TDAFW pump. The TDAFW pump supplies a common header capable of feeding both SGs by use of fail-open, air-operated control valves (4297 and 4298). The TDAFW pump will actuate automatically on a low-low level signal in both SGs, loss of voltage on 4160 V Buses 11A and 11B, or the ATWS mitigation system actuation circuitry (AMSAC). The pump can also be manually started from the control room.

The normal source of water for the AFW System is the CSTs which are located in the non-seismic Service Building. The Service Water (SW) System (LCO 3.7.8) can also be used to supply a safety-related source of water through normally closed motor operated valves (4013, 4027, and 4028) which supply each AFW train.

SAFW System

The SAFW System consists of two motor driven pumps configured into two separate trains (see Figure B 3.7.5-2). Each motor driven SAFW train provides 100% of the AFW flow capacity as assumed in the accident analyses and supplies one SG through the use of a normally open motor-operated stop check valve. Each pump has the capability to be realigned from the control room to feed the other SG via normally closed motor operated valves (9703A and 9703B). Each pump is powered from an independent Class 1E power supply and can be powered from the diesel generators provided that the breaker for the associated MDAFW pump is opened. The safety-related source of water for the SAFW System is the SW System through two normally closed motor operated valves (9629A and 9629B). Condensate can also be supplied by a 10,000 gallon condensate test tank and the yard fire hydrant yard loop.

The SAFW System is manually actuated in the event that the preferred AFW System has failed due to a high energy line break (HELB) in the Intermediate Building, a seismic or fire event. The SAFW trains are located in the SAFW Pump Building located adjacent to the Auxiliary Building.

(continued)

BASES

BACKGROUND (continued)

The SAFW Pump Building environment is controlled by room coolers which are supplied by the same SW header as the pump trains. These coolers are required when the outside air temperature is ≥ 80°F to ensure the SAFW Pump Building remains ≤ 120°F during accident conditions.

The AFW System is designed to supply sufficient water to the SG(s) to remove decay heat with SG pressure at the lowest MSSV set pressure plus 1%. Subsequently, the AFW System supplies sufficient water to cool the plant to RHR entry conditions, with steam released through the ARVs.

APPLICABLE SAFETY ANALYSES

The design basis of the AFW System is to supply water to the SG(s) to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the SGs at pressures corresponding to the lowest MSSV set pressure plus 1%.

The AFW System mitigates the consequences of any event with the loss of normal feedwater. The limiting Design Basis Accidents (DBAs) and transients for the AFW System are as follows (Ref. 2):

a. Feedwater Line Break (FWLB);

b. Loss of MFW (with and without offsite power);

c. Steam Line Break (SLB);

d. Small break loss of coolant accident (LOCA);

e. Steam generator tube rupture (SGTR); and

f. External events (tornados and seismic events).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The AFW System design is such that any of the above DBAs can be mitigated using the preferred AFW System or SAFW System. For the FWLB, SLB, and external events DBAs (items a, c, and f), the worst case scenario is the loss of all three preferred AFW trains due to a HELB in the Intermediate or Turbine Building, or a failure of the Intermediate Building block walls. For these three events, the use of the SAFW System within 10 minutes is assumed by the accident analyses. Since a single failure must also be assumed in addition to the HELB or external event, the capability of the SAFW System to supply flow to an intact SG could be compromised if the SAFW cross-tie is not available. For HELBs within containment, use of either the SAFW System or the AFW System to the intact SG is assumed within 10 minutes.

For the SGTR events (item e), the accident analyses assume that one AFW train is available upon a SI signal or low-low SG level signal. Additional inventory is being added to the ruptured SG as a result of the SGTR such that AFW flow is not a critical feature for this DBA.

For the loss of MFW events and small break LOCA (items b and d), two trains of AFW are assumed available (i.e., two MDAFW trains or the TDAFW train) upon a low-low SG level signal and SI signal, respectively. Two AFW trains are assumed available since no single failure can result in the loss of more than one AFW train. The loss of MFW is a Condition 2 event (Ref. 3) which places limits on the response of the RCS from the transient (e.g., no challenge to the pressurizer power operated relief valves is allowed). Two trains of AFW are required to maintain these limits. The small break LOCA analysis requires two trains of AFW to lower RCS pressure below the shutoff head of the SI pumps.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In addition to its accident mitigation function, the energy and mass addition capability of the AFW System is also considered with respect to HELBs within containment. For SLBs and FWLBs within containment, pump runout from all three AFW pumps is assumed for 10 minutes until operations can isolate the flow by tripping the AFW pumps or by closing the respective pump discharge flow path(s). Therefore, the motor operated discharge isolation valves for the motor MDAFW pump trains (4007 and 4008) are designed to limit flow to < 230 gpm. The TDAFW train is assumed to be at runout conditions (i.e., 600 gpm).

The AFW System satisfies the requirements of Criterion 3 of the NRC Policy Statement.

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary or containment.

The AFW System is comprised of two systems which are configured into five trains. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the SGs are OPERABLE (see Figures B 3.7.5-1 and 3.7.5-2). This requires that the following be OPERABLE:

a. Two MDAFW trains taking suction from the CSTs as required by LCO 3.7.6 (and capable of taking suction from the SW system within 10 minutes), and capable of supplying their respective SG with ≥ 200 gpm and ≤ 230 gpm total flow;

b. The TDAFW train taking suction from the CSTs as required by LCO 3.7.6 (and capable of taking suction from the SW system within 10 minutes), provided steam is available from both main steam lines upstream of the MSIVs, and capable of supplying both SGs with ≥ 200 gpm each; and

(continued)

BASES

LCO (continued)

c. Two motor driven SAFW trains capable of being initiated either locally or from the control room within 10 minutes, taking suction from the SW System, and supplying their respective SG and the opposite SG through the SAFW cross-tie line with ≥ 200 gpm.

The piping, valves, instrumentation, and controls in the required flow paths are also required to be OPERABLE. The TDAFW train is comprised of a common pump and two flow paths. A TDAFW train flow path is defined as the steam supply line and the SG injection line from/to the same SG. The failure of the pump or both flow paths renders the TDAFW train inoperable.

The cross-tie line for the preferred MDAFW pumps is not required for this LCO. The recirculation lines for the preferred AFW system and SAFW system pumps are not credited in the accident analysis and are also not required to be OPERABLE for this LCO since the MSSVs maintain the SG pressure below the pump's shutoff head.

The SAFW Pump Building room coolers are required to be OPERABLE when the outside air temperature is ≥ 80°F. If one room cooler is inoperable, the associated SAFW train is inoperable.

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW System is lost. In addition, the AFW System is required to supply enough makeup water to replace the lost SG secondary inventory as the plant cools to MODE 4 conditions.

In MODE 4, 5, or 6, the SGs are not normally used for heat removal, and the AFW System is not required.

(continued)

BASES (continued)

ACTIONS

A.1

If one of the TDAFW train flow paths is inoperable, action must be taken to restore the flow path to OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. The redundant OPERABLE turbine driven AFW pump flow path;

b. The availability of redundant OPERABLE MDAFW and SAFW pumps; and

c. The low probability of an event occurring that requires the inoperable TDAFW pump flow path.

A TDAFW train flow path is defined as the steam supply line and SG injection line from/to the same SG.

B.1

If one MDAFW train is inoperable, action must be taken to restore the train to OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. The redundant OPERABLE MDAFW train;

b. The availability of redundant OPERABLE TDAFW and SAFW pumps; and

c. The low probability of an event occurring that requires the inoperable MDAFW train.

(continued)

BASES

ACTIONS (continued)

C.1

With the TDAFW train inoperable, or both MDAFW trains inoperable, or one TDAFW train flow path and one MDAFW train inoperable to opposite SGs, action must be taken to restore OPERABLE status within 72 hours. If the inoperable MDAFW train supplies the same SG as the inoperable TDAFW flow path, Condition D must be entered.

The combination of failures which requires entry into this Condition all result in the loss of one train (or one flow path) of preferred AFW cooling to each SG such that redundancy is lost. The 72 hour Completion Time is reasonable, based on redundant capabilities afforded by the SAFW System, time needed for repairs, and the low probability of a DBA occurring during this time period.

D.1

With all AFW trains to one or both SGs inoperable, action must be taken to restore at least one train or TDAFW flow path to each affected SG to OPERABLE status within 4 hours.

The combination of failures which require entry into this Condition all result in the loss of preferred AFW cooling to at least one SG. If a SGTR were to occur in this condition, preferred AFW is potentially unavailable to the unaffected SG. If AFW is unavailable to both SGs, the accident analyses for small break LOCAs and loss of MFW would not be met.

(continued)

BASES

ACTIONS

D.1 (continued)

The two MDAFW trains of the preferred AFW System are normally used for decay heat removal during low power operations since air operated bypass control valves are installed in each train to better control SG level (see Figure B 3.7.5-1). Since a feedwater transient is more likely during reduced power conditions, 4 hours is provided to restore at least one train of additional preferred AFW before requiring a controlled cooldown. This will also provide time to find a condensate source other than the SW System for the SAFW System if all three AFW trains are inoperable. The 4 hour Completion Time is reasonable, based on redundant capabilities afforded by the SAFW System, time needed for repairs, and the low probability of a DBA occurring during this time period.

E.1

With one SAFW train inoperable, action must be taken to restore OPERABLE status within 14 days. This Condition includes the inoperability of one of the two SAFW cross-tie valves which requires declaring the associated SAFW train inoperable (e.g., failure of 9703B would result in declaring SAFW train D inoperable). The 14 day Completion Time is reasonable, based on redundant capabilities afforded by the AFW System, time needed for repairs, and the low probability of a HELB or other event which would require the use of the SAFW System during this time period.

F.1

With both SAFW trains inoperable, action must be taken to restore at least one SAFW train to OPERABLE status within 7 days. This Condition includes the inoperability of the SAFW cross-tie. The 7 day Completion Time is reasonable, based on redundant capabilities afforded by the AFW System, time needed for repairs, and the low probability of a HELB or other event which would require the use of the SAFW System during this time period.

(continued)

BASES

ACTIONS (continued)

G.1 and G.2

When Required Action A.1, B.1, C.1, D.1, E.1, or F.1 cannot be completed within the required Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant condition from full power conditions in an orderly manner and without challenging plant systems.

H.1

If all three preferred AFW trains and both SAFW trains are inoperable the plant is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety related equipment. In such a condition, the plant should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one MDAFW, TDAFW, or SAFW train to OPERABLE status. For the purposes of this Required Action, only one TDAFW train flow path and the pump must be restored to exit this Condition.

Required Action H.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one MDAFW, TDAFW, or SAFW train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the plant into a less safe condition.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the AFW and SAFW System water and steam supply flow paths provides assurance that the proper flow paths will exist for AFW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification, through a system walkdown, that those valves capable of being mispositioned are in the correct position.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.5.2

Periodically comparing the reference differential pressure and flow of each AFW pump in accordance with the inservice testing requirements of ASME, Section XI (Ref. 4) detects trends that might be indicative of an incipient failure. The Frequency of this surveillance is specified in the Inservice Testing Program, which encompasses Section XI of the ASME code. Section XI of the ASME code provides the activities and Frequencies necessary to satisfy this requirement.

This SR is modified by a Note indicating that the SR is only required to be met prior to entering MODE 1 for the TDAFW pump since suitable test conditions have not been established. This deferral is required because there is insufficient steam pressure to perform the test.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.3

Periodically comparing the reference differential pressure and flow of each SAFW pump in accordance with the inservice testing requirements of ASME, Section XI (Ref. 4) detects trends that might be indicative of an incipient failure. Because it is undesirable to introduce SW into the SGs while they are operating, this testing is performed using the test condensate tank. The Frequency of this surveillance is specified in the Inservice Testing Program, which encompasses Section XI of the ASME code. Section XI of the ASME code provides the activities and Frequencies necessary to satisfy this requirement.

SR 3.7.5.4

This SR verifies that each AFW and SAFW motor operated suction valve from the SW System (4013, 4027, 4028, 9629A, and 9629B), each AFW and SAFW discharge motor operated valve (4007, 4008, 9704A, 9704B, and 9746), and each SAFW cross-tie motor operated valve (9703A and 9703B) can be operated when required. The Frequency of this Surveillance is specified in the Inservice Test Program and is consistent with ASME Code, Section XI (Ref. 4).

SR 3.7.5.5

This SR verifies that AFW can be delivered to the appropriate SG in the event of any accident or transient that generates an actuation signal, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 24 month Frequency is acceptable based on operating experience and the design reliability of the equipment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.6

This SR verifies that the AFW pumps will start in the event of any accident or transient that generates an actuation signal by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal. The 24 month Frequency is based on the potential need to perform this Surveillance under the conditions that apply during a plant outage.

This SR is modified by a Note indicating that the SR is only required to be met prior to entering MODE 1 for the TDAFW pump since suitable test conditions may have not been established. This deferral is required because there is insufficient steam pressure to perform the test.

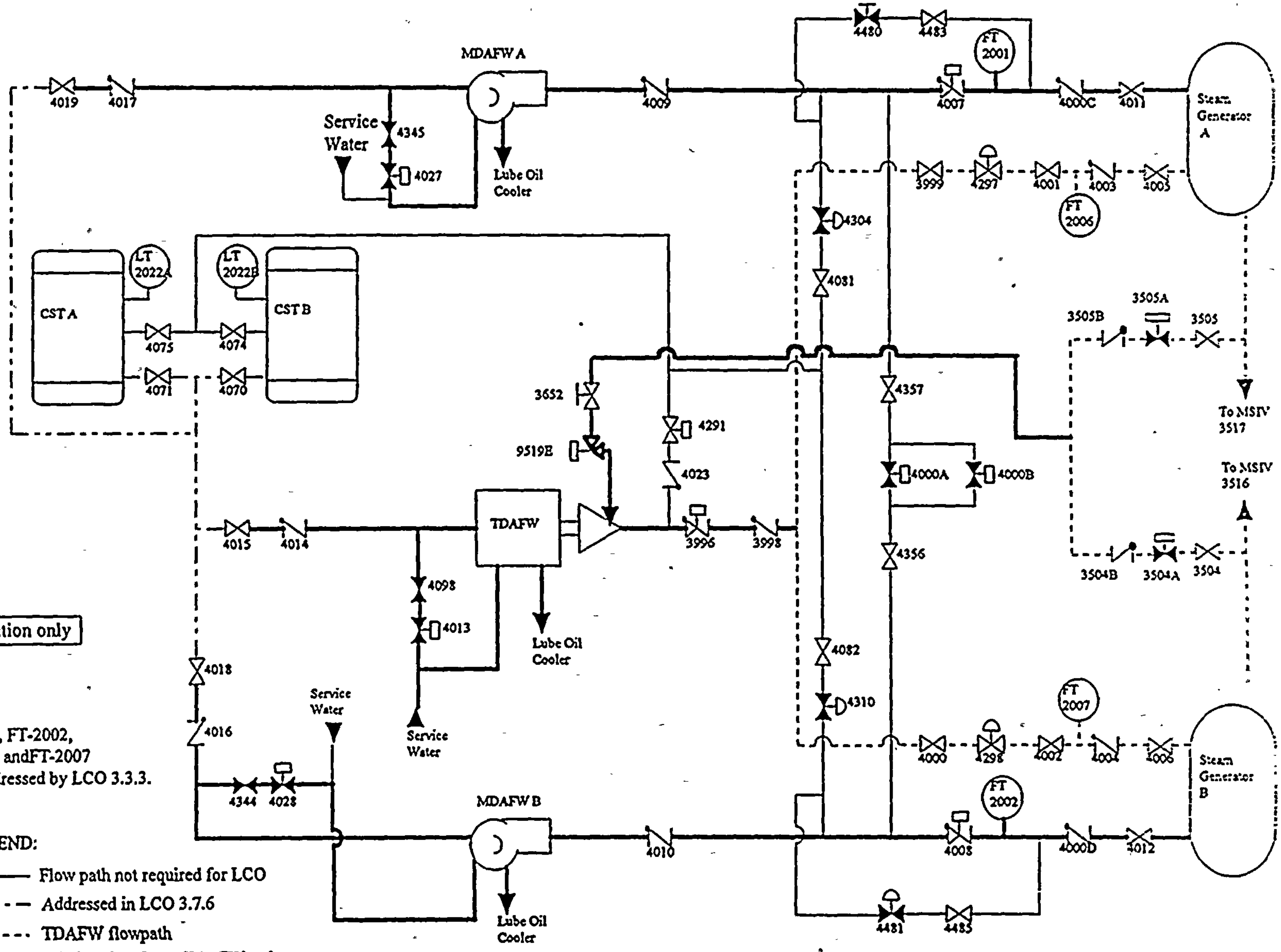
SR 3.7.5.7

This SR verifies that the SAFW System can be actuated and controlled from the control room. The SAFW System is assumed to be manually initiated within 10 minutes in the event that the preferred AFW System is inoperable. The Frequency of 24 months is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed at power.

REFERENCES

1. UFSAR, Section 10.5.
2. UFSAR Chapter 15.
3. American National Standard, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," N18.2-1973.
4. ASME, Boiler and Pressure Vessel Code, Section XI.

Figure B 3.7.5-1
Preferred AFW System

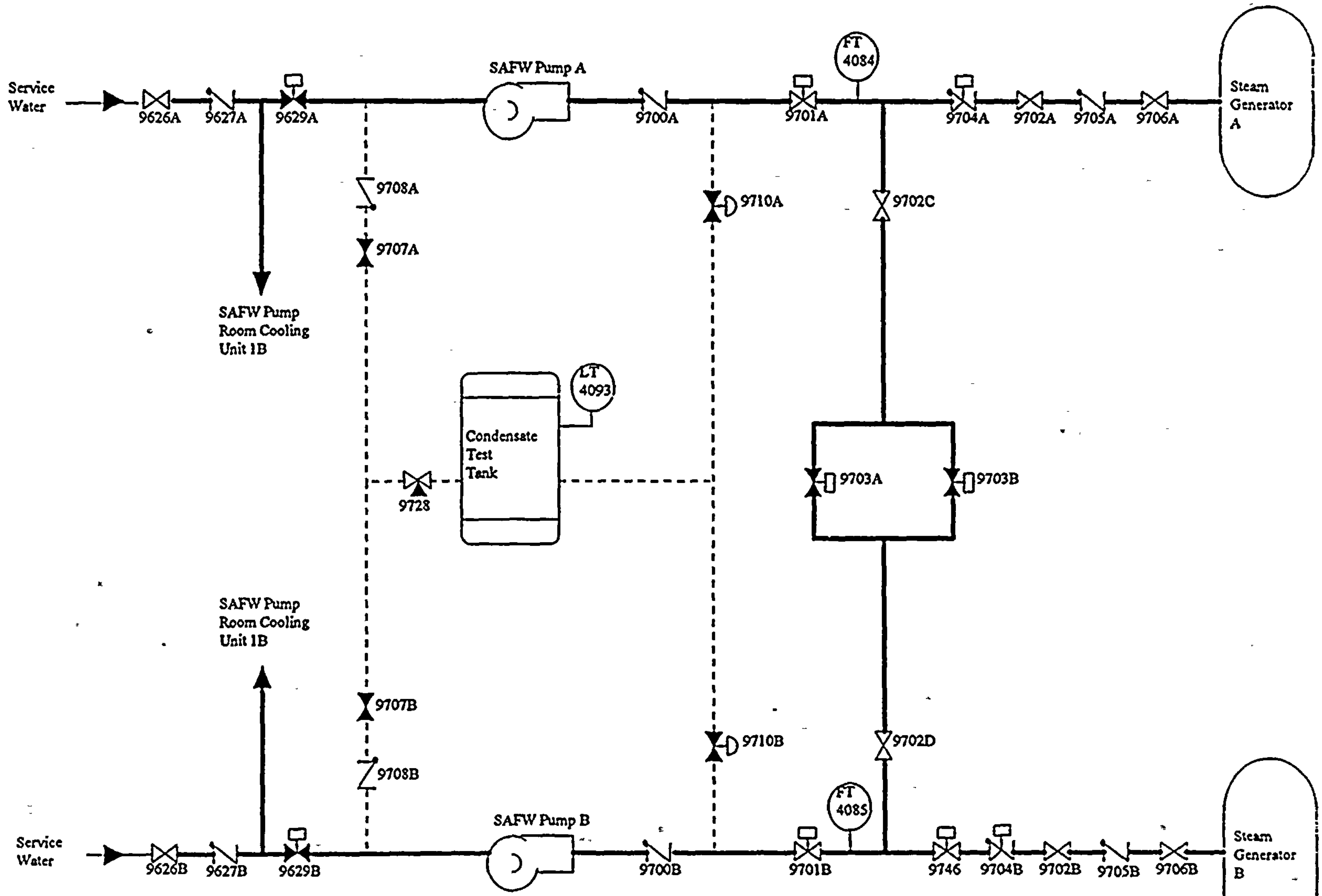


For illustration only

Note - FT-2001, FT-2002,
FT-2006 andFT-2007
also addressed by LCO 3.3.3.

LEGEND:
Flow path not required for LCO
Addressed in LCO 3.7.6
TDAFW flowpath
AFW Train (Note - TDAFW train includes both steam and both injection flowpaths)

Figure B 3.7.5-2
Standby AFW System



Legend:
- - - - - Flow path not required for LCO
——— SAFW Train

For illustration only

B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage Tanks (CSTs)

BASES

BACKGROUND

The CSTs provide a source of water to the steam generators (SGs) for removing decay and sensible heat from the Reactor Coolant System (RCS). The CST provides a passive flow of water, by gravity, to the preferred Auxiliary Feedwater (AFW) System (LCO 3.7.5) (see Figure B 3.7.5-1). The resulting steam produced in the SGs is released to the atmosphere by the main steam safety valves or the atmospheric relief valves.

When the main steam isolation valves are open, the preferred means of heat removal from the RCS is to discharge steam to the condenser by the nonsafety grade path of the steam dump valves. The condensed steam is then returned to the SGs by the main feedwater system. This has the advantage of conserving condensate while minimizing releases to the environment.

There are two 30,000 gallon CSTs located in the non-seismic Service Building (Ref. 1). The CSTs are not considered safety related components since the tanks are not protected against earthquakes or other natural phenomena, including missiles. The safety related source of condensate for the AFW and Standby AFW Systems is the Service Water (SW) System (LCO 3.7.8). The CSTs are connected by a common header which leads to the suction of all three AFW pumps. A single level transmitter is provided for each CST (LT-2022A and LT-2022B). The CSTs can be refilled from the condenser hotwell or the all-volatile-treatment condensate storage tank.

APPLICABLE SAFETY ANALYSES

The CSTs provide cooling water to remove decay heat and to cooldown the plant following all events in the accident analysis (Ref. 2) which assumes that the preferred AFW System is available immediately following an accident. For any event in which AFW is not required for at least 10 minutes following the accident, the SW System provides the source of cooling water to remove decay heat.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting Design Basis Accident (DBA) for the condensate volume is the loss of normal feedwater event and small break loss of coolant accident (LOCA) (Ref. 2). For the loss of normal feedwater event, flow from at least two AFW pumps is required upon a low level signal in either SG to meet the acceptance criteria for a Condition 2 event (Ref. 3). For the small break LOCA, two AFW pumps are required to lower the RCS pressure below the shutoff head of the safety injection pumps. Assuming that all three AFW pumps initiate at their maximum flowrate, the CSTs provide sufficient inventory for at least 20 minutes (at greater than required flowrates) before operator action to refill the CSTs or transfer suction to the SW System is required.

A nonlimiting event considered in CST inventory determinations is a main feedwater line break inside containment. This break has the potential for dumping condensate until terminated by operator action after 10 minutes since there is no automatic re-configuration of the AFW System. Following termination of the AFW flow to the affected SG by closing the AFW train discharge valves or stopping a pump, flow from the remaining AFW train or the SAFW System is directed to the intact SG for decay heat removal. This loss of condensate is partially compensated for by the retention of inventory in the intact SG.

For cooldowns following loss of all onsite and offsite AC electrical power, the CSTs contain sufficient inventory to provide a minimum of 2 hours of decay heat removal as required by NUREG-0737 (Ref. 4), item II.E.1.1. This beyond DBA requirement provides more limiting criteria for CST inventory.

The CSTs satisfy Criterion 3 of the NRC Policy Statement.

LCO

To satisfy accident analysis assumptions, the CST must contain sufficient cooling water to remove decay heat for at least 10 minutes following a loss of MFW event from 102% RTP. After this time period, the accident analyses assume that AFW pump suction can be transferred to the safety related suction source (i.e., the SW System).

(continued)

BASES

LCO (continued)

The required CST water volume is ≥ 22,500 gallons, which is based on the need to provide at least 2 hours of decay heat removal following loss of all AC electrical power. The CSTs are considered OPERABLE when at least 22,500 gallons of water is available. The 22,500 gal minimum volume is met if one CST is ≥ 21.5 ft or if both CSTs are ≥ 12.5 ft. Since the CSTs are 30,000 gallon tanks, only one CST is required to meet the minimum required water volume for this LCO.

The OPERABILITY of the CSTs is determined by maintaining the tank level at or above the minimum required water volume.

APPLICABILITY

In MODES 1, 2, and 3, the CSTs are required to be OPERABLE to support the AFW System requirements.

In MODE 4, 5, or 6, the CST is not required because the AFW System is not required to be OPERABLE.

ACTIONS

A.1 and A.2

If the CST water volume is not within limits, the OPERABILITY of the backup supply should be verified by administrative means within 4 hours. OPERABILITY of the backup feedwater supply must include verification that the flow paths from the backup water supply to the preferred AFW pumps are OPERABLE and immediately available upon AFW initiation, and that the backup supply has the required volume of water available. Alternate sources of water include, but is not limited to, the SW System and the all-volatile-treatment condensate tank. In addition, the CSTs must be restored to OPERABLE status within 7 days, because the backup supply may be performing this function in addition to its normal functions. Continued verification of the backup supply is not required due to the large volume of water typically available from these alternate sources. The 7 day Completion Time is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period requiring the CSTs.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the backup supply cannot be verified or the CSTs cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR verifies that the CSTs contain the required volume of cooling water. The 22,500 gal minimum volume is met if one CST is ≥ 21 ft or if both CSTs are ≥ 12.5 ft. The 12 hour Frequency is based on operating experience and the need for operator awareness of plant evolutions that may affect the CST inventory between checks. Also, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to abnormal deviations in the CST level.

REFERENCES

1. UFSAR, Section 10.7.4.
2. UFSAR, Chapter 15.
3. American National Standard, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," N18.2-1973.
4. NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

B 3.7 PLANT SYSTEMS

B 3.7.7 Component Cooling Water (CCW) System

BASES

BACKGROUND

The CCW System provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the CCW System also provides this function for various safety related and nonsafety related components. The CCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Service Water (SW) System, and thus to the environment. The safety related functions of the CCW system are covered by this LCO.

The CCW System consists of a single loop header supplied by two separate, 100% capacity, safety related pump and heat exchanger trains (Ref. 1) (see Figure B 3.7.7-1). Each CCW train consists of a manual suction and discharge valve, a pump, and a discharge check valve. The trains discharge to a common header which then supplies two heat exchangers, either of which can supply the safety related and non-safety related components cooled by CCW. The CCW loop header begins at the common piping at the discharge of the two parallel heat exchangers, and continues up to the first isolation valve for each component supplied by the CCW System. The CCW loop header then continues from the last isolation valve on the discharge of each supplied load to the common piping at the suction of the CCW pumps. Each pump is powered from a separate Class 1E electrical bus. An open surge tank in the system provides for thermal expansion and contraction of the CCW system and ensures that sufficient net positive suction head is available to the pumps. The CCW System is also provided with a radiation detector (R-17) to isolate the surge tank from the Auxiliary Building environment and to provide indication of a leak of radioactive water into the CCW System.

The CCW System is normally maintained below 100°F by the use of one pump train in conjunction with one heat exchanger. The standby CCW pump will automatically start if the system pressure falls to 50 psig.

(continued)

BASES

BACKGROUND (continued)

The principal safety related function of the CCW System is the removal of decay heat from the reactor via the Residual Heat Removal (RHR) System. Since the removal of decay heat via the RHR System is only performed during the recirculation phase of an accident, the CCW pumps do not receive an automatic start signal. Following the generation of a safety injection signal, the normally operating CCW pump will remain in service unless an undervoltage signal is present on either Class 1E electrical Bus 14 or Bus 16 at which time the pump is stripped from its respective bus. A CCW pump can then be manually placed into service prior to switching to recirculation operations which would not be required until a minimum of 46 minutes following an accident.

APPLICABLE SAFETY ANALYSES

The design basis of the CCW System is for one CCW train and one CCW heat exchanger to remove the loss of coolant accident (LOCA) heat load from the containment sump during the recirculation phase. The Emergency Core Cooling System (ECCS) and containment models for a LOCA each consider the minimum performance of the CCW System. The normal temperature of the CCW is ≤ 100 °F, and, during LOCA conditions, a maximum temperature of 120°F is assumed. This prevents the CCW System from exceeding its design temperature limit of 200°F, and provides for a gradual reduction in the temperature of containment sump fluid as it is recirculated to the Reactor Coolant System (RCS) by the ECCS pumps. The CCW System is designed to perform its function with a single failure of any active component, assuming a coincident loss of offsite power.

The CCW trains, heat exchangers, and loop headers are manually placed into service prior to the recirculation phase of an accident (i.e., 46 minutes following a large break LOCA).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The CCW System can also function to cool the plant from RHR entry conditions (T_{avg} < 350°F), to MODE 5 (T_{avg} < 200°F), during normal cooldown operations. The time required to cool from 350°F to 200°F is a function of the number of CCW and RHR trains operating. Since CCW is comprised of a large loop header, a passive failure can be postulated during this cooldown period which results in draining the CCW System within a short period of time. The CCW System is also vulnerable to external events such as tornados. The plant has been evaluated for the loss of CCW under these conditions with the use of alternate cooling mechanisms (e.g., providing for natural circulation using the atmospheric relief valves and the Auxiliary Feedwater System) with acceptable results (Ref. 1). Leaks within the CCW System during post accident conditions can be mitigated by the available makeup water sources.

The CCW System satisfies Criterion 3 of the NRC Policy Statement.

LCO

In the event of a DBA, one CCW train, one heat exchanger, and the loop header is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water (see Figure B 3.7.7-1). To ensure this requirement is met, two trains of CCW, two heat exchangers, and the loop header must be OPERABLE. At least one CCW train will operate assuming the worst case single active failure occurs coincident with a loss of offsite power.

A CCW train is considered OPERABLE when the pump is OPERABLE and capable of providing cooling water to the loop header. The automatic start logic associated with low CCW system pressure is not required for this LCO. In addition, if a CCW pump fails an Inservice Testing Program surveillance (e.g., pump developed head) the pump is only declared inoperable when the flowrate to required components is below that required to provide the heat removal capability assumed in the accident analyses.

(continued)

BASES

LCO (continued)

The CCW loop header is considered OPERABLE when the associated piping, valves, surge tank, and the instrumentation and controls required to provide cooling water to the following safety related components are available and capable of performing their safety related function:

a. Two RHR heat exchangers;

b. Two RHR pump mechanical seal coolers and bearing water jackets;

c. Three safety injection pump mechanical seal coolers; and

d. Two containment spray pump mechanical seal coolers.

The CCW loop header temperature must also be ≤ 120°F prior to the CCW cooling water reaching the first isolation valve supplying these components.

The CCW loop header begins at the common piping at the discharge of the CCW heat exchangers and continues up to the first isolation valve for each of the above components. The CCW loop header then continues from the last isolation valve on the discharge of each of the above components to the common piping at the suction of the CCW pumps.

The portion of CCW piping, valves, instrumentation and controls between the isolation valves to components a through d above is addressed by the following LCOs:

a. LCO 3.4.6, "RCS Loops - MODE 4,"

b. LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled,"

c. LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled,"

(continued)

BASES

LCO (continued)

d. LCO 3.5.2, "ECCS - MODES 1, 2, and 3,"

e. LCO 3.5.3, "ECCS - MODE 4,"

f. LCO 3.9.3, "RHR and Coolant Circulation - Water Level ≥ 23 Ft," and

g. LCO 3.9.4, "RHR and Coolant Circulation - Water Level < 23 Ft."

The CCW piping inside containment for the reactor coolant pumps (RCPs) and the reactor support coolers also serves as a containment isolation boundary. This is addressed by LCO 3.6.3, "Containment Isolation Boundaries."

The CCW system radiation detector (R-17) is not required to be OPERABLE for this LCO since the CCW system outside containment is not required to be a closed system.

The isolation of CCW from other components or systems not required for safety may render those components or systems inoperable but does not affect the OPERABILITY of the CCW System.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CCW System is a normally operating system, which must be capable to perform its post accident safety functions. The failure to perform this safety function could result in the loss of reactor core cooling and containment integrity during the recirculation phase following a LOCA.

In MODE 5 or 6, the OPERABILITY requirements of the CCW System are determined by LCO 3.4.7, LCO 3.4.8, LCO 3.9.3, and LCO 3.9.4.

(continued)

BASES (continued)

ACTIONS

A.1

If one CCW train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE CCW train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE CCW train could result in loss of CCW function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this period.

B.1

If one CCW heat exchanger is inoperable, action must be taken to restore OPERABLE status within 31 days. In this Condition, the remaining OPERABLE heat exchanger is adequate to perform the heat removal function. However, the overall reliability is reduced because a passive failure in the OPERABLE CCW heat exchanger could result in a loss of CCW function. The 31 day Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a passive failure of the remaining heat exchanger.

C.1 and C.2

If the CCW train or CCW heat exchanger cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

D.1, D.2, and D.3

With both CCW trains, both CCW heat exchangers, or the loop header inoperable, action must be immediately initiated to restore OPERABLE status to one CCW train, one CCW heat exchanger, and the loop header. In this Condition, there is no OPERABLE CCW System available to provide necessary cooling water which is a loss of a safety function. Also, the plant must be placed in a MODE in which the consequences of a loss of CCW coincident with an accident are reduced. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The plant is not required to exit the Applicability for this LCO (i.e., enter MODE 5) until at least one CCW train, one CCW heat exchanger, and the loop header is restored to OPERABLE status to support RHR operation.

Required Actions D.1, D.2, and D.3 are modified by a Note indicating that all required MODE changes or power reductions required by other LCOs are suspended until one CCW train, one CCW heat exchanger, and the loop header are restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the plant into a less safe condition.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

Verifying the correct alignment for manual and power operated valves in the CCW flow path provides assurance that the proper flow paths exist for CCW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification, through a system walkdown, that those valves capable of being mispositioned are in the correct position.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

This SR is modified by a Note indicating that the isolation of the CCW flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CCW loop header.

SR 3.7.7.2

This SR verifies that the two motor operated isolation valves to the RHR heat exchangers (738A and 738B) can be operated when required since the valves are normally maintained closed. The Frequency of this Surveillance is specified in the Inservice Test Program and is consistent with ASME Code, Section XI (Ref. 2).

REFERENCES

1. UFSAR, Section 9.2.2.

2. ASME, Boiler and Pressure Vessel Code, Section XI.

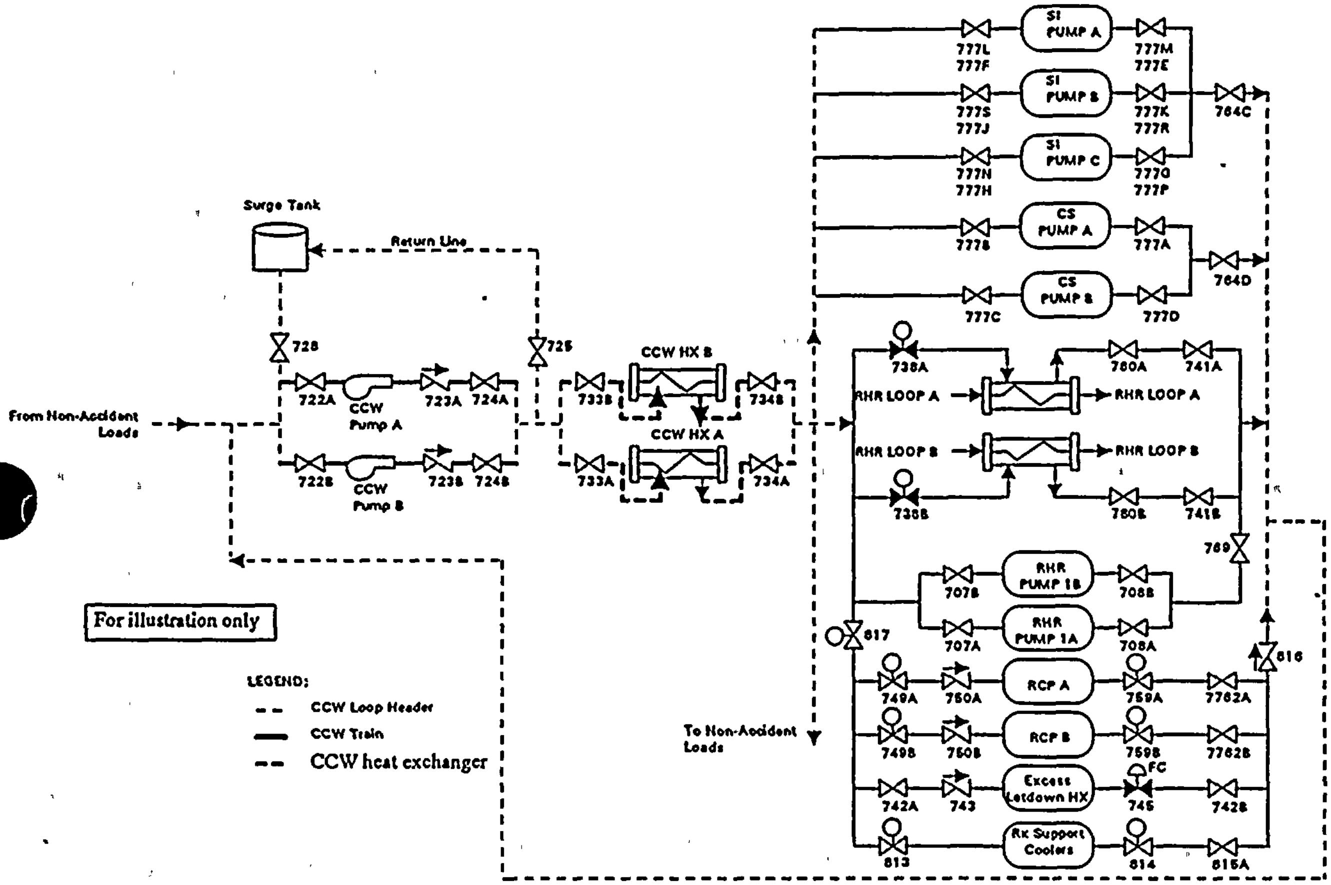


Figure B 3.7.7-1
CCW System

B 3.7 PLANT SYSTEMS

B 3.7.8 Service Water (SW) System

BASES

BACKGROUND

The SW System provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the SW system also provides this function for various safety related and nonsafety related components. The safety related functions of the SW System are covered by this LCO.

The SW System consists of a single loop header supplied by two separate, 100% capacity, safety related pump trains (Ref. 1) (see Figure B 3.7.8-1). The physical design of the SW System is such that one 100% capacity pump from each class 1E electrical bus (Buses 17 and 18) is arranged on a common piping header which then supplies the SW loop header. For the purposes of this LCO, a SW train is based on electrical source only.

Each train is powered from a separate Class 1E electrical bus and consists of two 100% capacity pumps and associated discharge check valves and manual isolation valves. The SW loop header begins from the discharge of the trains and supplies the safety related and nonsafety related components cooled by SW. The pumps in the system are normally manually aligned. One pump in each train is selected to automatically start upon receipt of an undervoltage signal on its respective bus. Upon receipt of a safety injection signal, each SW pump will automatically start in a predetermined sequence.

The SW loop header supplies the cooling water to all safety related and nonsafety related components. The nonsafety related and long-term safety functions (e.g., component cooling water heat exchangers) can be isolated from the loop header through use of redundant motor operated isolation valves. These valves automatically close on a coincident safety injection signal and undervoltage signal on Buses 14 and 16.

(continued)

BASES

BACKGROUND (continued)

The suction source for the SW System is the screenhouse which is a seismic structure located on Lake Ontario. The discharge from the SW System supplied loads returns back to Lake Ontario. The principal safety related functions of the SW system is the removal of decay heat from the reactor via the Component Cooling Water (CCW) System, provide cooling water to the diesel generators (DGs) and containment recirculation fan coolers (CRFCs) and to provide a safety related source of water to the Auxiliary Feedwater (AFW) System.

APPLICABLE SAFETY ANALYSES

The design basis of the SW System is for one SW train in conjunction with a 100% capacity containment cooling system (i.e., CRFC) to provide for heat removal following a steam line break (SLB) inside containment to ensure containment integrity. The SW System is also designed, in conjunction with the CCW System and a 100% capacity Emergency Core Cooling System and containment cooling system, to remove the loss of coolant accident (LOCA) heat load from the containment sump during the recirculation phase (Ref. 2). This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is recirculated to the Reactor Coolant System by the ECCS pumps. The SW System is designed to perform its function with a single failure of any active component, assuming a coincident loss of offsite power.

Following the receipt of a safety injection signal, all four SW pumps are designed to start (if not already running) to supply the system loads. If a coincident safety injection and undervoltage signal occurs, then each nonsafety related and nonessential load within the SW System is isolated by redundant motor operated valves that are powered by separate Class 1E electrical trains. The SW pumps are sequenced to start within 17 seconds following a safety injection signal. The selected SW pumps are sequenced to start after a 40 second time delay following energization of the electrical bus supplying the selected pump (i.e., Bus 17 or Bus 18) after an undervoltage signal.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SW trains and loop header are assumed to supply to following components following an accident:

a. The CRFCs, DGs and safety injection pump bearing housing coolers immediately following a safety injection signal (i.e., after the loop header becomes refilled);

b. The preferred AFW and SAFW pumps within 10 minutes following receipt of a low SG level signal; and

c. The CCW heat exchangers within 46 minutes following a safety injection signal.

The SW system, in conjunction with the CCW System, can also cool the plant from residual heat removal (RHR) entry conditions (T_{avg} < 350°F) to MODE 5 (T_{avg} < 200°F) during normal operations. The time required to cool from 350°F to 200°F is a function of the number of CCW and RHR System trains that are operating. Since SW is comprised of a large loop header, a passive failure can be postulated during this cooldown period which results in failing the SW System to potentially multiple safety related functions. The SW system has been evaluated to demonstrate the capability to meet cooling needs with an assumed 500 gal leak. The SW System is also vulnerable to external events such as tornados. The plant has been evaluated for the loss of SW under these conditions with the use of alternate cooling mechanisms (e.g., providing for natural circulation using the atmospheric relief valves and the AFW Systems) with acceptable results (Ref. 1).

The temperature of the fluid supplied by the SW System is also a consideration in the accident analyses. If the cooling water supply to the containment recirculation fan coolers and CCW heat exchangers is too warm, the accident analyses with respect to containment pressure response following a SLB and the containment sump fluid temperature following a LOCA may no longer be bounding. If the cooling water supply is too cold, the containment heat removal systems may be more efficient than assumed in the accident analysis. This causes the backpressure in containment to be reduced which potentially results in increased peak clad temperatures.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SW system satisfies Criterion 3 of the NRC Policy Statement.

LCO

In the event of a DBA, one SW train and the loop header is required to be OPERABLE to provide the minimum heat removal capability to ensure that the system functions to remove post accident heat loads as assumed in the safety analyses. To ensure this requirement is met, two trains of SW and the loop header must be OPERABLE (see Figure B 3.7.8-1). At least one SW train will operate assuming that the worst case single active failure occurs coincident with the loss of offsite power.

A SW train is defined based on electrical power source such that SW Pumps A and C form one train and SW Pumps B and D form the second train. A SW train is considered OPERABLE when one pump in the train is OPERABLE and capable of taking suction from the screenhouse and providing cooling water to the loop header as assumed in the accident analyses. This includes consideration of available net positive suction head (NPSH) to the SW pumps and the temperature of the suction source. The following are the minimum requirements of the screenhouse bay with respect to OPERABILITY of the SW pumps:

a. Level ≥ 5 feet; and

b. Temperature ≥ 35°F above 50% RTP and ≤ 80°F.

The lower screenhouse bay temperature is only specified above 50% RTP since this value is only a consideration when evaluating LOCA at or near full power conditions. In addition, if a SW pump fails on Inservice Testing Program surveillance (e.g., pump developed head), the pump is only declared inoperable when the flowrate to required components is below that required to provide the heat removal capability assumed in the accident analyses (Ref. 1).

(continued)

BASES

LCO (continued)

An OPERABLE SW train also requires that all nonessential and nonsafety related loads can be isolated by the six motor operated isolation valves which are powered from the same Class 1E electrical train as the pumps. Therefore, motor operated valves 4609, 4614, 4615, 4616, 4663, and 4670 must be OPERABLE and capable of closing for SW Pumps A and C while valves 4613, 4664, 4733, 4734, 4735, and 4780 must be OPERABLE and capable of closing for SW Pumps B and D.

The SW loop header is considered OPERABLE when the associated piping, valves, and the instrumentation and controls required to provide cooling water from each OPERABLE SW train to the following safety related components are available and capable of performing their safety related function:

a. Four CRFCs;

b. Two CCW heat exchangers;

c. Two DGs;

d. Three preferred AFW pumps;

e. Two standby AFW pumps; and

f. Three safety injection pump bearing housing coolers.

An OPERABLE SW loop header also requires a flow path through the diesel generator (4665, 4760, 4669, and 4668B) and CRFC (4623, 4640, 4756 and 4639) cross-ties.

The SW loop header begins at the common piping at the discharge of both SW pump trains and ends at the first isolation valve for each of the above components. Since the SW System discharges back to Lake Ontario, the cooling water flow path through the above components and subsequent discharge is addressed under their respective LCO. This includes:

a. LCO 3.5.2, "ECCS - MODES 1, 2, and 3;"

b. LCO 3.5.3, "ECCS - MODE 4;"

(continued)

BASES

LCO (continued)

c. LCO 3.6.6, "CS, CRFC, and Post-Accident Charcoal Systems;"

d. LCO 3.7.5, "AFW Systems;"

e. LCO 3.7.7, "CCW System;"

f. LCO 3.8.1, "AC Sources - MODES 1, 2, 3, and 4;" and

g. LCO 3.8.2, "AC Sources - MODES 5 and 6."

The SW piping inside containment for the CRFCs and the reactor compartment coolers also serves as a containment isolation boundaries. This is addressed under LCO 3.6.3, "Containment Isolation Boundaries."

APPLICABILITY

In MODES 1, 2, 3, and 4, the SW System is a normally operating system which must be capable of performing its post accident safety functions. The failure to perform this safety function could result in the loss of reactor core cooling during the recirculation phase following a LOCA or loss of containment integrity following a SLB.

In MODES 5 and 6, the OPERABILITY requirements of the SW system are determined by LCO 3.6.6, LCO 3.7.7, and LCO 3.8.2.

ACTIONS

A.1

If one SW train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE SW train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE SW train could result in loss of SW System function. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time period.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the SW train cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1

With both SW trains or the loop header inoperable, the plant is in a condition outside of the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

Required Action C.1 is modified by a Note requiring that the applicable Conditions and Required Actions of LCO 3.7.7, "CCW System," be entered for the component cooling water heat exchanger made inoperable by SW. This note is provided since the inoperable SW system may prevent the plant from reaching MODE 5 as required by LCO 3.0.3 if both CCW heat exchangers are rendered inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR verifies that adequate NPSH is available to operate the SW pumps and that the SW suction source temperature is within the limits assumed by the accident analyses. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.2

Verifying the correct alignment for manual, power operated, and automatic valves in the SW flow path provides assurance that the proper flow paths exist for SW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. This SR does not require any testing or valve manipulation; rather, it involves verification, through a system walkdown, that those valves capable of being mispositioned are in the correct position.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

This SR is modified by a Note indicating that the isolation of the SW flow to individual components or systems may render those components inoperable, but does not affect the OPERABILITY of the SW System.

SR 3.7.8.3

This SR verifies that all SW loop header cross-tie valves are locked in the correct position. This includes verification that manual valves 4623, 4639, 4640, 4665, 4668B, 4669, 4756, and 4760 are locked open and that manual valves 4610, 4611, 4612, and 4779 are locked closed. The 31 day Frequency is based on engineering judgement, is consistent with the procedural controls governing locked valves, and ensures correct valve positions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.4

This SR verifies proper automatic operation of the SW motor operated isolation valves on an actual or simulated actuation signal (i.e., coincident safety injection and undervoltage signal). SW is a normally operating system that cannot be fully actuated as part of normal testing. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.8.5

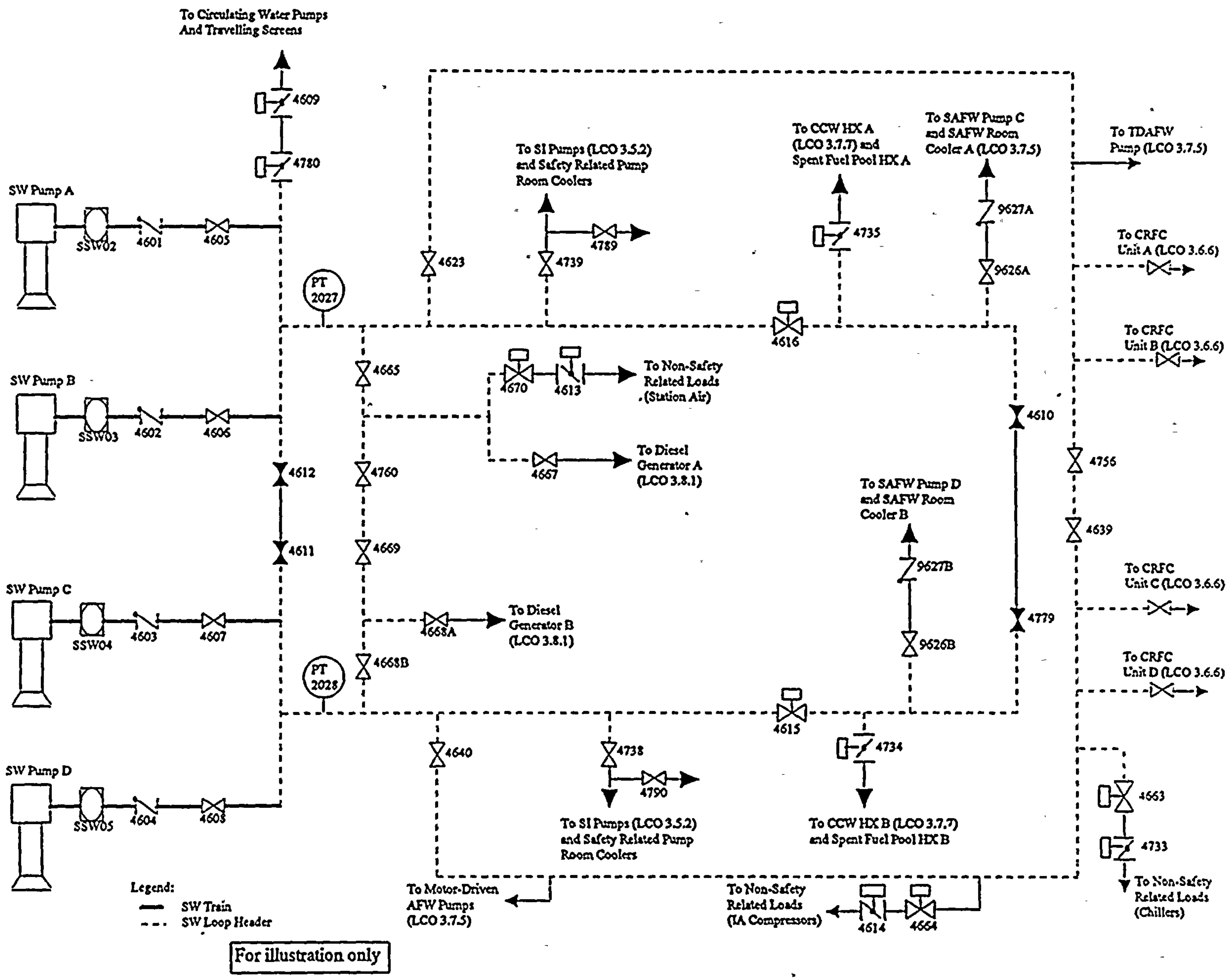
This SR verifies proper automatic operation of the SW pumps on an actual or simulated actuation signal. This includes the actuation of the SW pumps following an undervoltage signal and following a coincident safety injection and undervoltage signal. SW is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 9.2.1.

2. UFSAR, Section 6.2.

Figure B 3.7.8-1
SW System



B 3.7 PLANT SYSTEMS

B 3.7.9 Control Room Emergency Air Treatment System (CREATS)

BASES

BACKGROUND

According to Atomic Industry Forum (AIF) GDC 11 (Ref. 1), a control room shall be provided which permits continuous occupancy under any credible postaccident condition without excessive radiation exposures of personnel. Exposure limits are provided in GDC 19 of 10 CFR 50, Appendix A (Ref. 2) which requires that control room personnel be restricted to 5 rem whole body, or its equivalency, for the duration of the accident. The CREATS provides a protected environment from which operators can control the plant following an uncontrolled release of radioactivity for 30 days without exceeding this 5 rem whole body limit. The CREATS is part of the Control Building ventilation system.

The CREATS consists of a high efficiency particulate air (HEPA) filter, activated charcoal adsorbers for removal of gaseous activity (principally iodines), and two fans (control room return air fan and emergency return air fan) (see Figure B 3.7.9-1). Ductwork, dampers, and instrumentation also form part of the system as well as demisters to remove water droplets from the air stream (Ref. 3).

The CREATS is an emergency system, parts of which may operate during normal plant operations. Actuation of the CREATS places the system in one of five separate states of the emergency mode of operation, depending on the initiation signal. The following are the normal and emergency modes of operation for the CREATS:

<u>CREATS Mode A</u>

The CREATS is in the standby mode with the exception that the control room return air fan is in operation.

(continued)

BASES

BACKGROUND (continued)

CREATS Mode B

This is the CREATS configuration following an accident with a radiation release as detected by radiation monitor R-1. Upon receipt of an actuation signal, the control room emergency return air fan will actuate and system dampers align to recirculate a maximum of 2000 cfm (approximately one fourth of the Control Building Ventilation System design) through the CREATS charcoal and HEPA filters. All outside air that enters the CREATS, as controlled by an air adjust switch (S-81), is also circulated through the CREATS charcoal and HEPA filters.

CREATS Mode C

This is the same CREATS configuration as Mode B with the exception that all outside air is isolated to the control room by one damper in each air supply flow path.

CREATS Mode D

This is the CREATS configuration following the detection of smoke within the Control Building. Upon receipt of an actuation signal, the system continues to draw outside air. However, the control room emergency return air fan will actuate and system dampers align to recirculate a maximum of 2000 cfm through the CREATS and HEPA filters. This effectively purges the control room air environment.

CREATS Mode E

This is the same CREATS configuration as Mode D with exception that all outside air is isolated to the control room by one damper in each air supply flow path.

(continued)

BASES

BACKGROUND (continued)

CREATS Mode F

This is the CREATS configuration following the detection of a toxic gas as indicated by the chlorine or ammonia detectors, or high radiation as detected by R-36 (gas), R-37 (particulate), or R-38 (iodine). Upon receipt of an actuation signal, the system aligns itself consistent with Mode C except that two dampers in each air supply path are isolated.

Normally open air supply isolation dampers are arranged in series so that the failure of one damper to close will not result in a breach of isolation.

The air entering the control room is continuously monitored by radiation and toxic gas detectors. One detector output above the setpoint will cause actuation of the emergency radiation state or toxic gas isolation state, as required. The actions of the toxic gas and high radiation state (Mode F) are more restrictive, and will override the actions of the emergency radiation state (Mode B or C). Only the high radiation state CREATS Mode F is addressed by this LCO.

APPLICABLE SAFETY ANALYSES

The location of components and CREATS related ducting within the control room envelope ensures an adequate supply of filtered air to all areas requiring access. The CREATS provides airborne radiological protection for the control room operators in MODES 1, 2, 3, and 4, as demonstrated by the control room accident dose analyses for the most limiting design basis loss of coolant accident and steam generator tube rupture (Ref. 3). This analysis shows that with credit for the CREATS, or with credit for instantaneous isolation of the control room coincident with the accident initiator and no CREATS filtration train available, the dose rates to control room personnel remain within GDC 19 limits.

In MODES 5 and 6, and during movement of irradiated fuel assemblies, the CREATS ensures control room habitability in the event of a fuel handling accident or waste gas decay tank rupture accident.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The CREATS satisfies Criterion 3 of the NRC Policy Statement.

LCO

The CREATS is comprised of a filtration train and two independent and redundant isolation damper trains all of which are required to be OPERABLE. Total system failure could result in exceeding a dose of 5 rem to the control room operators in the event of a large radioactive release.

The CREATS is considered OPERABLE when the individual components necessary to permit CREATS Mode F operation are OPERABLE (see Figure B 3.7.9-1). The CREATS filtration train is OPERABLE when the associated:

a. Control room return air and emergency return air fans are OPERABLE and capable of providing forced flow;

b. HEPA filters and charcoal adsorbers for the emergency return air fan are not excessively restricting flow, and are capable of performing their filtration functions; and

c. Ductwork, valves, and dampers (including AKD06 and AKD09) are OPERABLE, and air circulation can be maintained.

The CREATS isolation dampers are considered OPERABLE when the damper (AKD01, AKD04, AKD05, AKD08, and AKD10) can close on an actuation signal to isolate outside air or is closed with motive force removed. Two dampers are provided for each outside air path.

(continued)

BASES

LCO (continued)

In addition, the control room boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors. Opening of the access doors for entry and exit does not violate the control room boundary. An access door may be opened for extended periods provided a dedicated individual is stationed at the access door to ensure closure, if required (i.e., the individual performs the isolation function), the door is able to be closed within 30 seconds upon indication of the need to close the door, and the CREATS filtration train is OPERABLE.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CREATS must be OPERABLE to control operator exposure during and following a DBA.

In MODE 5 or 6, the CREATS is required to cope with the release from the rupture of a waste gas decay tank.

During movement of irradiated fuel assemblies, the CREATS must be OPERABLE to cope with the release from a fuel handling accident.

ACTIONS

A.1 and A.2

With the CREATS filtration train inoperable, action must be taken to restore OPERABLE status within 48 hours or isolate the control room from outside air. In this Condition, the isolation dampers are adequate to perform the control room protection function but no means exist to filter the release of radioactive gas within the control room. The 48 hour Completion Time is based on the low probability of a DBA occurring during this time frame, and the ability of the CREATS dampers to isolate the control room.

Required Action A.2 is modified by a Note which allows the control room to be unisolated for ≤ 1 hour every 24 hours. This allows fresh air makeup to improve the working environment within the control room and is acceptable based on the low probability of a DBA occurring during this makeup period.

(continued)

BASES

ACTIONS (continued)

B.1

With one CREATS isolation damper inoperable for one or more outside air flow paths, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CREATS isolation damper is adequate to perform the control room protection function. However, the overall reliability is reduced because a single failure in the OPERABLE CREATS isolation damper could result in loss of CREATS function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining isolation damper to provide the required isolation capability.

C.1 and C.2

In MODE 1, 2, 3, or 4, if the Required Actions of Conditions A or B cannot be completed within the required Completion Time, the plant must be placed in a MODE that minimizes accident risk. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1 , D.2.1, and D.2.2

In MODE 5 or 6 or during movement of irradiated fuel assemblies, if the Required Actions of Conditions A or B cannot be completed within the required Completion Time, action must be taken to immediately place the OPERABLE isolation damper(s) in CREATS Mode F. This action ensures that the remaining damper(s) are OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected.

(continued)

BASES

ACTIONS

D.1 , D.2.1, and D.2.2 (continued)

An alternative to Required Action D.1 is immediately suspend activities that could result in a release of radioactivity that might enter the control room. This requires the suspension of CORE ALTERATIONS and the suspension of movement of irradiated fuel assemblies. This places the plant in a condition that minimizes risk. This does not preclude the movement of fuel or other components to a safe position.

E.1

In MODE 1, 2, 3, or 4, if both CREATS isolation dampers for one or more outside air flow paths are inoperable, the CREATS may not be capable of performing the intended function and the plant is in a condition outside the accident analyses. Failure of the integrity of the control room boundary (i.e., walls, floors, ceilings, ductwork or access doors) also results in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

F.1, and F.2, and F.3

In MODE 5 or 6 or during movement of irradiated fuel assemblies with two CREATS isolation dampers for one or more outside air flow paths inoperable, action must be taken immediately to restore one isolation damper in each affected air supply path to OPERABLE status. In addition, action must be taken immediately to suspend activities that could result in a release of radioactivity that might enter the control room. This requires the suspension of CORE ALTERATIONS and the suspension of movement of irradiated fuel assemblies. This places the plant in a condition that minimizes accident risk. This does not preclude the movement of fuel or other components to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not too severe, testing each CREATS filtration train once every 31 days for ≥ 15 minutes provides an adequate check of this system. The 31 day Frequency is based on the reliability of the equipment.

SR 3.7.9.2

This SR verifies that the required CREATS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The CREATS filter tests are in general accordance with Regulatory Guide 1.52 (Ref. 4). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. The minimum required flowrate through the CREATS filtration train is 2000 cubic feet per minute (±10%). Specific test Frequencies and additional information are discussed in detail in the VFTP. However, the maximum surveillance interval for refueling outage tests is based on 24 month refueling cycles and not 18 month cycles as defined by Regulatory Guide 1.52 (Ref. 4).

SR 3.7.9.3

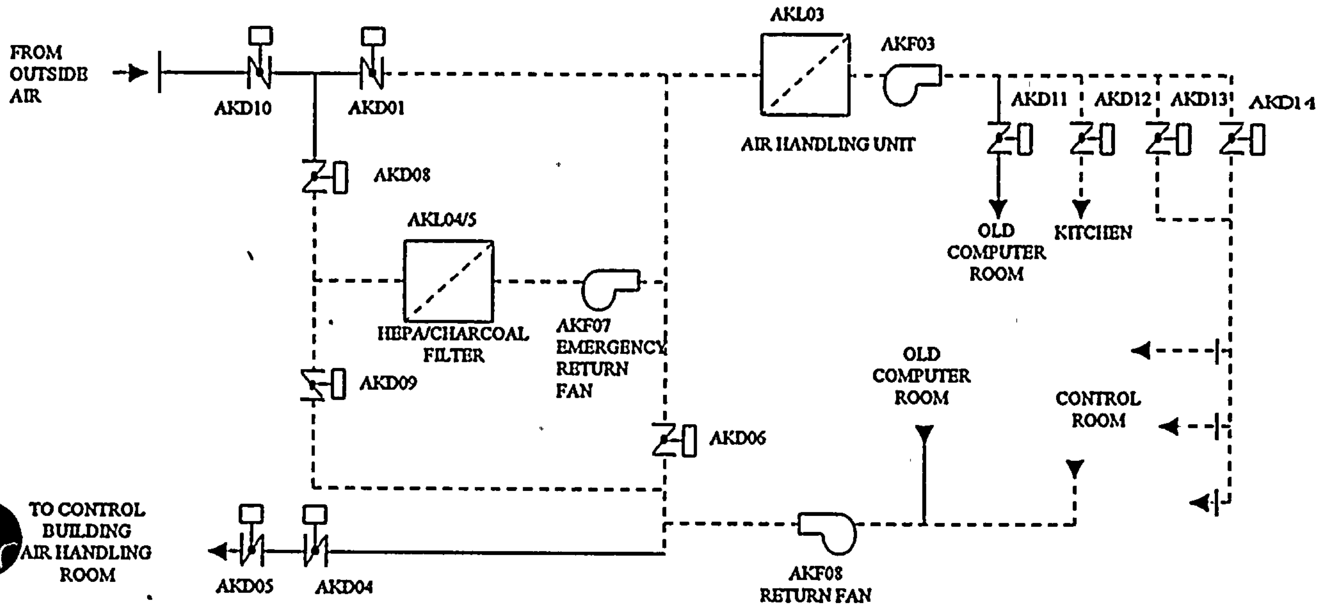
This SR verifies that the CREATS filtration train starts and operates and each CREATS isolation damper actuates on an actual or simulated actuation signal. The Frequency of 24 months is based on Regulatory Guide 1.52 (Ref. 4).

(continued)

BASES (continued)

REFERENCES

1. Atomic Industry Forum (AIF) GDC 11, Issued for comment July 10, 1967.
2. 10 CFR 50, Appendix A, GDC 19.
3. UFSAR, Section 6.4.
4. Regulatory Guide 1.52, Revision 2.



Legend:
- - - - CREATS Filtration Train

For illustration only

Notes:

1. Outside air flowpath isolation dampers includes AKD01, AKD04, AKD05, AKD08, and AKD10.
2. The CREATS filtration train does not include the air handling unit (AKL03 and AKF03).

Figure B 3.7.9-1
CREATS

B 3.7 PLANT SYSTEMS

B 3.7.10 Auxiliary Building Ventilation System (ABVS)

BASES

BACKGROUND

The ABVS filters airborne radioactive particulates from the area of the spent fuel pool (SFP) following a fuel handling accident. The ABVS, in conjunction with other normally operating systems, also provides environmental control of temperature and humidity in the Auxiliary Building including the SFP area.

The ABVS consists of an air handling unit, a series of exhaust fans, charcoal filters, ductwork, and dampers (Ref. 1). The exhaust fans include the following fans which all discharge into a common ductwork that supplies the Auxiliary Building main exhaust fans A and B (see Figure B 3.7.10-1):

a. Intermediate Building exhaust fans A and B;

b. Auxiliary Building exhaust fan C;

c. Auxiliary Building charcoal filter fans A and B;

d. Auxiliary Building exhaust fan G; and

e. Control access exhaust fans A and B.

The only components which filter the environment associated with the SFP are the Auxiliary Building main exhaust fans and Auxiliary Building exhaust fan C. Therefore, these are the only fans considered with respect to the ABVS in this LCO.

(continued)

BASES

BACKGROUND (continued)

Auxiliary Building exhaust fan C takes suction from the SFP and decontamination pit areas on the operating level of the Auxiliary Building. The air is first drawn through the SFP Charcoal Adsorber System which consists of roughing filters and charcoal adsorbers. The roughing filters protect the charcoal adsorbers from being fouled with dirt particles while the charcoal adsorbers remove the radioactive iodines from the atmosphere. Auxiliary Building exhaust fan C then discharges into the common ductwork that supplies the Auxiliary Building main exhaust fans. This common ductwork contains a high efficiency particulate air (HEPA) filter which is not credited in the dose analyses.

The Auxiliary Building main exhaust fans are each 100% capacity fans which can maintain a negative pressure on the operating floor of the Auxiliary Building through orientation of the system dampers. This negative pressure causes air flow on the operating floor to be toward the SFP which ensures that air in the vicinity of the SFP is first filtered through the SFP Charcoal Adsorber System. The Auxiliary Building main exhaust fans and exhaust fan C are powered from non-Engineered Safeguards Features buses.

The Auxiliary Building main exhaust fans discharge to the plant vent stack. The plant vent stack is continuously monitored for noble gases (R-14), particulates (R-13) and iodine (R-10B). During normal power operation, the ABVS is placed in the "out" mode by the interlock mode switch where "out" defines the status of the SFP charcoal filters. This causes all exhaust fans without any HEPA or charcoal filters (excluding the Auxiliary Building Main exhaust fans) and Auxiliary Building exhaust fan C to trip upon a signal from R-10B, R-13 or R-14 to stop the release of any radioactive gases. During fuel movement within the Auxiliary Building, the interlock mode switch is placed in the "in" mode such that only exhaust fans without any HEPA or charcoal filters (excluding Auxiliary Building main exhaust fans) are tripped.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The ABVS design basis is established by the consequences of the limiting Design Basis Accident (DBA), which is a fuel handling accident. The analysis of the fuel handling accident, given in Reference 2, assumes that all fuel rods in an assembly are damaged. The DBA analysis of the fuel handling accident assumes that Auxiliary Building exhaust fan C, the SFP Charcoal Adsorber System, and one Auxiliary Building main exhaust fan are OPERABLE. The accident analysis accounts for the reduction in airborne radioactive material provided by the minimum filtration system components which result in offsite doses well within the limits of 10 CFR 100 (Ref. 3). The failure of any or all of these filtration system components results in doses which are slightly higher but still within 10 CFR 100 limits. The fuel handling accident assumptions and the analysis follow the guidance provided in Regulatory Guide 1.25 (Ref. 4).

The remainder of the ABVS described in the Background is not required for any DBA since it is non-safety related and supplied only from offsite power sources.

The ABVS satisfies Criterion 3 of the NRC Policy Statement.

LCO

The ABVS is required to be OPERABLE to ensure that offsite doses are well within the limits of 10 CFR 100 (Ref. 3) following a fuel handling accident in the Auxiliary Building. The failure of the ABVS coincident with a fuel handling accident results in doses which are slightly higher but still within 10 CFR 100 limits.

The ABVS is considered OPERABLE when the individual components necessary to control exposure in the Auxiliary Building following a fuel handling accident are OPERABLE and in operation (see Figure B 3.7.10-1). The ABVS is considered OPERABLE when its associated:

a. Auxiliary Building exhaust fan C and either Auxiliary Building main exhaust fan A or B is OPERABLE and in operation;

(continued)

BASES

LCO (continued)

b. Auxiliary Building main exhaust fan HEPA filter and SFP charcoal adsorbers are not excessively restricting flow, and the SFP Charcoal Adsorber System is capable of performing its filtration function;

c. Ductwork, valves, and dampers are OPERABLE, and air circulation and negative pressure can be maintained on the Auxiliary Building operating floor; and

d. Interlock mode switch is placed in the "in" mode.

APPLICABILITY

During movement of irradiated fuel in the Auxiliary Building, the ABVS is required to be OPERABLE to alleviate the consequences of a fuel handling accident. The ABVS is only required when one or more fuel assemblies in the Auxiliary Building has decayed < 60 days since being irradiated. Any fuel handling accident which occurs after 60 days results in offsite doses which are well within 10 CFR 100 limits (Ref. 3) due to the decay rate of iodine.

Since a fuel handling accident can only occur as a result of fuel movement, the ABVS is not MODE dependant and only required when irradiated fuel is being moved.

ACTIONS

A.1

When the ABVS is inoperable, action must be taken to place the plant in a condition in which the LCO does not apply. Action must be taken immediately to suspend movement of irradiated fuel assemblies in the Auxiliary Building. This does not preclude the movement of fuel to a safe position.

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies in the Auxiliary Building which have decayed < 60 days since being irradiated, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

This SR verifies the OPERABILITY of the ABVS. During fuel movement operations, the ABVS is designed to maintain a slight negative pressure in the Auxiliary Building to prevent unfiltered LEAKAGE. This SR ensures that Auxiliary Building exhaust fan C, and either Auxiliary Building main exhaust fan A or B are in operation and that the ABVS interlock mode switch is in the correct position. The Frequency of 24 hours is based on engineering judgement and shown to be acceptable through operating experience.

SR 3.7.10.2

This SR verifies the integrity of the Auxiliary Building enclosure. The ability of the Auxiliary Building to maintain negative pressure with respect to the uncontaminated outside environment must be periodically verified to ensure proper functioning of the ABVS. During fuel movement operations, the ABVS is designed to maintain a slight negative pressure in the Auxiliary Building to prevent unfiltered leakage. This SR ensures that a negative pressure is being maintained in the Auxiliary Building. The Frequency of 24 hours is based on engineering judgement and shown to be acceptable through operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10.3

This SR verifies that the required SFP Charcoal Adsorber System testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The SFP Charcoal Adsorber System filter tests are in general accordance with Regulatory Guide 1.52 (Ref. 5). The VFTP includes testing charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). There is no minimum required flowrate through the SFP charcoal adsorbers since SR 3.7.10.2 requires verification that a negative pressure is maintained during fuel movement in the Auxiliary Building. As long as this minimum pressure is maintained by drawing air from the surface of the SFP through the SFP charcoal adsorbers, the assumptions of the accident analyses are met. Specific test frequencies and additional information are discussed in detail in the VFTP. However, the maximum surveillance interval for refueling outage tests is based on 24 month refueling cycles and not 18 month cycles as defined by Regulatory Guide 1.52 (Ref. 5).

REFERENCES

1. UFSAR, Section 9.4.2.
2. UFSAR, Section 15.7.3.2.
3. 10 CFR 100.
4. Regulatory Guide 1.25, Rev. 0.
5. Regulatory Guide 1.52, Rev. 2.

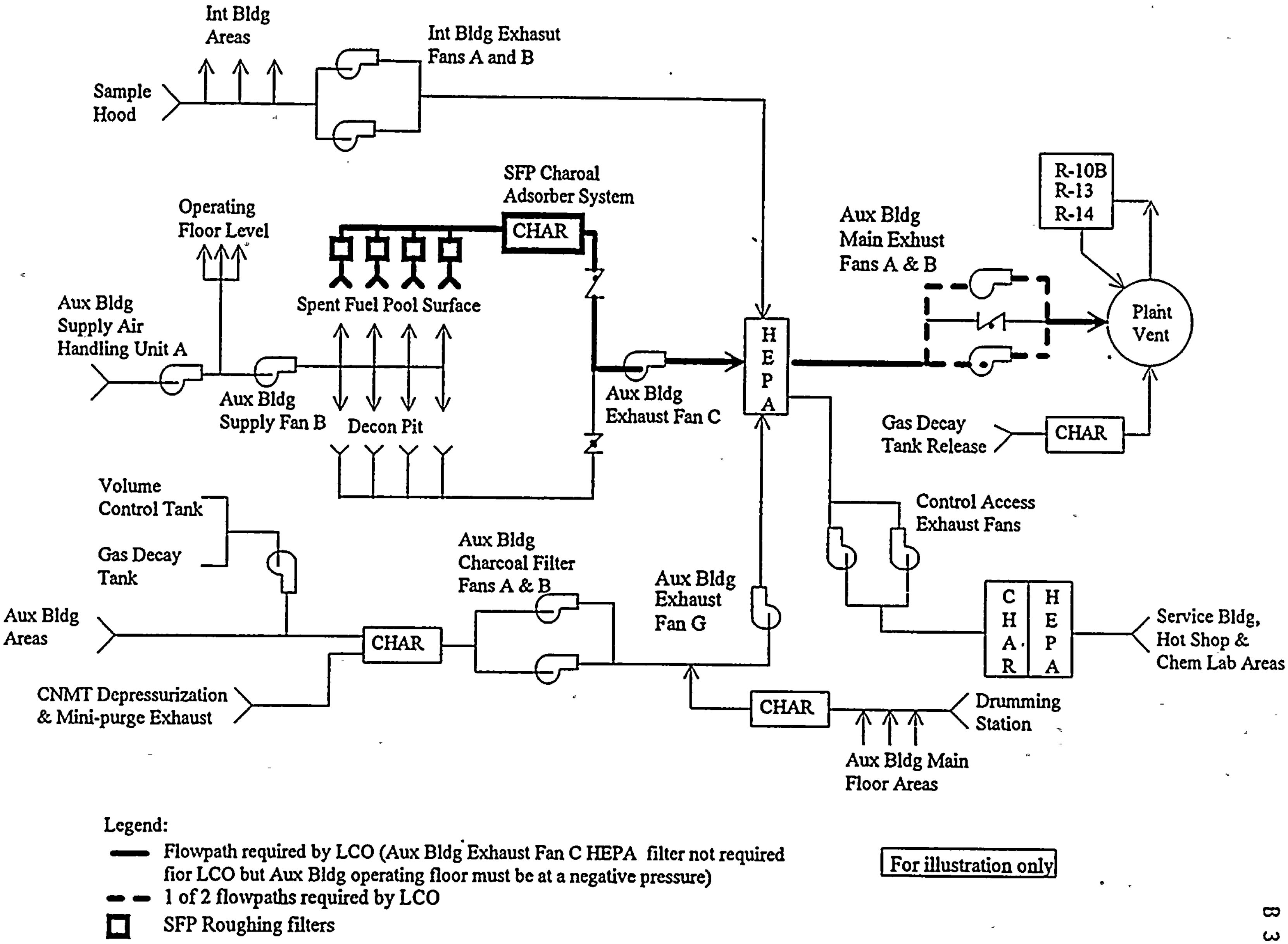


Figure B 3.7.10-1
ABVS

B 3.7 PLANT SYSTEMS

B 3.7.11 Spent Fuel Pool (SFP) Water Level

BASES

BACKGROUND

The minimum water level in the spent fuel pool (SFP) meets the assumptions of iodine decontamination factors following a fuel handling accident. The specified water level provides protection against exceeding the offsite dose limits.

The SFP is a seismically designed structure located in the Auxiliary Building (Ref. 1). The pool is internally clad with stainless steel that has a leak chase system at each weld seam to minimize accidental drainage through the liner. The SFP is also provided with a barrier between the spent fuel storage racks and the fuel transfer system winch. This barrier, up to the height of the spent fuel racks, prevents inadvertent drainage of the SFP via the fuel transfer tube.

The SFP Cooling System is designed to maintain the pool ≤ 120°F during normal conditions and refueling operations (Ref. 2). The cooling system normally takes suction near the surface of the SFP such that a failure of any pipe in the system will not drain the pool. The cooling system return line to the pool also contains a 0.25 inch vent hole located near the SFP surface level to prevent siphoning. Finally, control board alarms exist with respect to the SFP level and temperature. These features all help to prevent inadvertent draining of the SFP.

APPLICABLE SAFETY ANALYSES

The minimum water level in the SFP is an assumption of the fuel handling accident described in the UFSAR (Ref. 3) and Regulatory Guide 1.25 (Ref. 4). The resultant 2 hour thyroid dose per person at the exclusion area boundary as based on this assumption is a small fraction of the 10 CFR 100 (Ref. 5) limits.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Based on the requirements of Reference 4, there must be 23 ft of water between the top of the damaged fuel bundle and the fuel pool surface during a fuel handling accident. With 23 ft of water available, the assumptions of Reference 4 can be used directly. These assumptions include the use of a decontamination factor of 100 in the analysis for iodine. A decontamination factor of 100 enables the analysis to assume that 99% of the total iodine released from the pellet to cladding gap of all dropped fuel assembly rods is retained by the SFP water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory.

In practice, this LCO preserves this assumption for the bulk of the fuel in the storage racks. In the case of a single bundle dropped and lying horizontally on top of the spent fuel storage racks, however, there may be < 23 ft of water between the top of the fuel bundle and the surface, indicated by the width of the bundle and difference between the top of the rack and active fuel. To offset this small nonconservatism, the analysis assumes that all fuel rods fail, although analysis shows that only the first few rows fail from a hypothetical maximum drop.

The SFP water level satisfies Criterion 2 of the NRC Policy Statement.

LCO

The SFP water level is required to be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks. The specified water level preserves the assumptions of the fuel handling accident analysis (Ref. 3). As such, it is the minimum required during movement of irradiated fuel assemblies within the SFP.

(continued)

BASES (continued)

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the spent fuel pool, since the potential for a release of fission products exists. Since a fuel handling accident can only occur during movement of fuel, this LCO is not applicable during other conditions. During refueling operations in MODE 6, the SFP water level (and boron concentration) are in equilibrium with the refueling water cavity. The water level under these conditions is then controlled by LCO 3.9.5, "Refueling Cavity Water Level" which requires the refueling cavity water level to be maintained ≥ 23 feet above the top of the reactor vessel flange. A refueling cavity water level of ≥ 23 feet above the top of the reactor vessel flange will result in > 23 feet of water above the top of the active fuel in the storage racks assuming that atmospheric pressure within containment and the Auxiliary Building are equivalent.

ACTIONS

A.1

When the initial conditions assumed in the fuel handling accident analysis cannot be met, steps should be taken to preclude the accident from occurring. When the SFP water level is lower than the required level, the movement of irradiated fuel assemblies in the SFP is immediately suspended. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position (e.g., movement to an available rack position).

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply since if moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving irradiated fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR verifies sufficient SFP water is available in the event of a fuel handling accident. The water level in the spent fuel pool must be checked periodically during movement of irradiated fuel assemblies to ensure the fuel handling accident assumptions are met. The 7 day Frequency is appropriate because the volume in the pool is normally stable and the SFP is designed to prevent drainage below 23 ft. Water level changes are controlled by plant procedures and are acceptable based on operating experience.

Verification of SFP water level can be accomplished by several means. The top of the upper SFP pump suction line is 23 ft above the fuel stored in the pool. If there is ≥ 23 ft of water above the reactor vessel flange (as required by LCO 3.9.5), with equal pressure in the containment and the Auxiliary Building, then at least 23 ft of water is available above the top of the active fuel in the storage racks.

In addition to the physical design features, there are two SFP level alarms (LAL 634) which are available to alert the operators of changing SFP level. A low level alarm will actuate when the SFP water level falls 4 inches or more from the normal level while a high level alarm will actuate when the SFP water level rises 4 inches or more from the normal level. These alarms must receive a calibration consistent with industry practices before they are to be used to meet this SR.

REFERENCES

1. UFSAR, Section 9.1.2.
2. UFSAR, Section 9.1.3.
3. UFSAR, Section 15.7.3.
4. Regulatory Guide 1.25, Rev. 0.
5. 10 CFR 100.11.

B 3.7 PLANT SYSTEMS

B 3.7.12 Spent Fuel Pool (SFP) Boron Concentration

BASES

BACKGROUND

The water in the spent fuel pool (SFP) normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that a limiting k_{eff} of 0.95 be maintained in the absence of soluble boron. Hence, the design of both SFP regions is based on the use of unborated water such that configuration control (i.e., controlling the movement of the fuel assembly and checking the location of each assembly after movement) maintains each region in a subcritical condition during normal operation with the regions fully loaded.

The double contingency principle discussed in ANSI N-16.1-1975 (Ref. 1) and Reference 2 allows credit for soluble boron under abnormal or accident conditions, since only a single accident need be considered at one time. For example, the most severe accident scenarios are associated with the movement of fuel from Region 1 to Region 2, and accidental misloading of a fuel assembly in Region 2. Either scenario could potentially increase the reactivity of Region 2. To mitigate these postulated criticality related accidents, boron is dissolved in the pool water. Safe operation of the storage racks with no movement of assemblies may therefore be achieved by controlling the location of each assembly in accordance with LCO 3.7.13, "Spent Fuel Pool (SFP) Storage." Within 7 days prior to movement of an assembly into a SFP region, it is necessary to perform SR 3.7.12.1. Prior to moving an assembly into a SFP region, it is also necessary to perform SR 3.7.13.1 or 3.7.13.2 as applicable.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The postulated accidents in the SFP can be divided into two basic categories (Ref. 3 and 4). The first category are events which cause a loss of cooling in the SFP. Changes in the SFP temperature could result in an increase in positive reactivity. However, the positive reactivity is ultimately limited by voiding (which would result in the addition of negative reactivity) and the SFP geometry which is designed assuming use of unborated water even though soluble boron is available (see Specification 4.3.1.1). The second category is related to the movement of fuel assemblies in the SFP (i.e., a fuel handling accident) and is the most limiting accident scenario with respect to reactivity. The types of accidents within this category include an incorrectly transferred fuel assembly (e.g., transfer from Region 1 to Region 2 of an unirradiated or an insufficiently depleted fuel assembly) and a dropped fuel assembly. However, for both of these accidents, the negative reactivity effect of the soluble boron compensates for the increased reactivity. By closely controlling the movement of each assembly and by checking the location of each assembly after movement, the time period for potential accidents which credit use of the soluble boron may be limited to a small fraction of the total operating time.

The concentration of dissolved boron in the SFP satisfies Criterion 2 of the NRC Policy Statement.

LCO

The SFP boron concentration is required to be ≥ 300 ppm. The specified concentration of dissolved boron in the SFP preserves the assumptions used in the analyses of the potential critical accident scenarios as described in References 3 and 4 (i.e., a fuel handling accident). This concentration of dissolved boron is the minimum required concentration for fuel assembly storage and movement within the SFP until the fuel assemblies have been verified to be stored correctly.

(continued)

BASES (continued)

APPLICABILITY

This LCO applies whenever fuel assemblies are stored in the SFP, until a SFP verification has been performed following the last movement of fuel assemblies in the SFP. The SFP verification is accomplished by performing SR 3.7.13.1 or SR 3.7.13.2 after movement of fuel assemblies depending on which SFP region was affected by the fuel movement. If fuel was moved into both regions, then both SR 3.7.13.1 and SR 3.7.13.2 must be performed after the completion of fuel movement before exiting the Applicability of this LCO. This LCO does not apply following the verification, since the verification would confirm that there are no misloaded fuel assemblies. With no further fuel assembly movements in progress, there is no potential for a misloaded fuel assembly or a dropped fuel assembly.

This LCO does not apply to fuel movement within a SFP region since the accident analyses assume each region is completely filled in an infinite array.

ACTIONS

A.1, A.2.1, and A.2.2

When the concentration of boron in the SFP is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. The concentration of boron is restored simultaneously with suspending movement of fuel assemblies. An acceptable alternative is to immediately initiate action to perform a SFP verification (SR 3.7.13.1 and SR 3.7.13.2). The performance of this verification removes the plant from the Applicability of this LCO. This does not preclude movement of a fuel assembly to a safe position (e.g., movement to an available rack position).

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply since if the LCO is not met while moving irradiated fuel assemblies in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

This SR verifies that the concentration of boron in the SFP is within the limit. As long as this SR is met, the analyzed accidents are fully addressed. The 31 day Frequency is appropriate because the volume and boron concentration in the pool is normally stable and all water level changes and boron concentration changes are controlled by plant procedures.

This SR is required to be performed prior to fuel assembly movement into Region 1 or Region 2 and must continue to be performed until the necessary SFP verification is accomplished (i.e., SR 3.7.13.1 and 3.7.13.2).

REFERENCES

1. ANSI N16.1-1975, "American National Standard for Nuclear Criticality Safety in Operations with Fissionable Materials Outside Reactors."

2. Letter from B.K. Grimes, NRC, to All Power Reactor Licensees, Subject: "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," dated April 14, 1978.

3. Westinghouse, "Criticality Analysis of the R.E. Ginna Nuclear Power Plant Fresh and Spent Fuel Racks, and Consolidated Rod Storage Canisters," dated June 1994.

4. UFSAR, Section 15.7.3.

B 3.7 PLANT SYSTEMS

B 3.7.13 Spent Fuel Pool (SFP) Storage

BASES

BACKGROUND

The spent fuel pool (SFP) is divided into two separate and distinct regions (see Figure B 3.7.13-1) which, for the purpose of criticality considerations, are considered as separate pools (Ref. 1). Region 1, with 176 storage positions, is designed to accommodate new or spent fuel utilizing a two of four checkerboard arrangement. A fuel assembly with an enrichment of ≤ 4.05 wt% can be stored at any available location in Region 1 since the accident analyses were performed assuming that Region 1 was filled with fuel assemblies of this enrichment. A fuel assembly with an enrichment > 4.05 wt% U-235 can also be stored in Region 1 provided that integral burnable poisons are present in the assemblies such that k-infinity is ≤ 1.458. The existing design uses Integral Fuel Burnable Absorbers (IFBAs) as the poison for fuel assemblies with enrichments > 4.05 wt%. IFBAs consist of neutron absorbing material which provides equivalencing reactivity holddown (i.e., neutron poison) that allows storage of higher enrichment fuel. The neutron absorbing material is a non-removable or integral part of the fuel assembly once it is applied. The infinite multiplication factor, K-infinity, is a reference criticality point of each fuel assembly that if maintained ≤ 1.458, will result in a k_{eff} ≤ 0.95 for Region 1. The K-infinity limit is derived for constant conditions of normal reactor core configuration (i.e., typical geometry of fuel assemblies in vertical position arranged in an infinite array) at cold conditions (i.e., 68°F and 14.7 psia).

Region 2, with 840 storage positions, is designed to accommodate fuel of various initial enrichments which have accumulated minimum burnups within the acceptable domain according to Figure 3.7.13-1, in the accompanying LCO. The storage of fuel assemblies which are within the acceptable range of Figure 3.7.13-1 in Region 2 ensures a K_{eff} ≤ 0.95 in this region.

(continued)

BASES

BACKGROUND (continued)

Consolidated rod storage canisters can also be stored in either region in the SFP provided that the minimum burnup of Figure 3.7.13-1 is met. In addition, all canisters placed into service after 1994 must have ≤ 144 rods or ≥ 256 rods (Ref. 2). The canisters are stainless steel containers which contain the fuel rods of a maximum of two fuel assemblies (i.e., 358 rods). All bowed, broken, or otherwise failed fuel rods are first stored in a stainless steel tube of 0.75 inch outer diameter before being placed in a canister. Each canister will accommodate 110 failed fuel rod tubes.

The water in the SFP normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that a limiting k_{eff} of 0.95 be maintained in the absence of soluble boron. Hence, the design of both regions is based on the use of unborated water such that configuration control (i.e., controlling the movement of the fuel assembly and checking the location of each assembly after movement) maintains each region in a subcritical condition during normal operation with the regions fully loaded.

The double contingency principle discussed in ANSI N16.1-1975 (Ref. 3) and Reference 4 allows credit for soluble boron under abnormal or accident conditions, since only a single accident need be considered at one time. For example, the most severe accident scenarios are associated with the movement of fuel from Region 1 to Region 2, and accidental misloading of a fuel assembly in Region 2. Either scenario could potentially increase the reactivity of Region 2. To mitigate these postulated criticality related accidents, boron is dissolved in the pool water. Safe operation of the storage racks with no movement of assemblies may therefore be achieved by controlling the location of each assembly in accordance with this LCO. Within 7 days prior to movement of an assembly into a SFP region, it is necessary to perform SR 3.7.12.1. Prior to moving an assembly into a SFP region, it is also necessary to perform SR 3.7.13.1 or 3.7.13.2 as applicable.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The postulated accidents in the SFP can be divided into two basic categories (Refs. 2 and 5). The first category are events which cause a loss of cooling in the SFP. Changes in the SFP temperature could result in an increase in positive reactivity. However, the positive reactivity is ultimately limited by voiding (which would result in the addition of negative reactivity) and the SFP geometry which is designed assuming use of unborated water even though soluble boron is available (see Specification 4.3.1.1). The second category is related to the movement of fuel assemblies in the SFP (i.e., a fuel handling accident) and is the most limiting accident scenario with respect to reactivity. The types of accidents within this category include an incorrectly transferred fuel assembly (e.g., transfer from Region 1 to Region 2 of an unirradiated or an insufficiently depleted fuel assembly) and a dropped fuel assembly. However, for both of these accidents, the negative reactivity effect of the soluble boron compensates for the increased reactivity. By closely controlling the movement of each assembly and by checking the location of each assembly after movement, the time period for potential accidents which credit use of the soluble boron may be limited to a small fraction of the total operating time.

The configuration of fuel assemblies in the spent fuel pool satisfies Criterion 2 of the NRC Policy Statement.

LCO

The restrictions on the placement of fuel assemblies within the SFP ensure the k_{eff} of the SFP will always remain < 0.95, assuming the pool to be flooded with unborated water (Specification 4.3.1.1). For fuel assemblies stored in Region 1, each assembly must have a K-infinity of ≤ 1.458.

For fuel assemblies stored in Region 2, initial enrichment and burnup shall be within the acceptable area of the Figure 3.7.13-1. The x-axis of Figure 3.7.13-1 is the nominal U-235 enrichment wt% which does not include the ± 0.05 wt% tolerance that is allowed for fuel manufacturing and listed in Specification 4.3.1.1.

(continued)

BASES (continued)

APPLICABILITY

This LCO applies whenever any fuel assembly is stored in the SFP.

ACTIONS

A.1

When the configuration of fuel assemblies stored in either Region 1 or Region 2 of the SFP is not within the LCO limits, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with Specification 4.3.1.1. This compliance can be made by relocating the fuel assembly to a different region.

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply since if the LCO is not met while moving irradiated fuel assemblies in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the action is independent of reactor operation. Therefore, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

This SR verifies by administrative means that the K-infinity of each fuel assembly is ≤ 1.458 prior to storage in Region 1. If the initial enrichment of a fuel assembly is ≤ 4.05 wt%, a K-infinity of ≤ 1.458 is always maintained. For fuel assemblies with enrichment > 4.05 wt%, a minimum number of IFBAs must be present in each fuel assembly such that k-infinity ≤ 1.458 prior to storage in Region 1. This verification is only required once for each fuel assembly since the burnable poisons, if required, are an integral part of the fuel assembly and will not be removed. The initial enrichment of each assembly will also not change (i.e., increase) while partially burned assemblies are less reactive than when they were new (i.e., fresh). Performance of this SR ensures compliance with Specification 4.3.1.1.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1 (continued)

Though not required for this LCO, this SR must also be performed after completion of fuel movement into Region 1 to exit the Applicability of LCO 3.7.12, "SFP Boron Concentration."

This SR is modified by a Note which states that this verification is not required when transferring a fuel assembly from Region 2 to Region 1. The verification is not required since Region 2 is the limiting SFP region, and as such, the fuel has already been verified to be acceptable for storage in Region 1.

SR 3.7.13.2

This SR verifies by administrative means that the initial enrichment and burnup of the fuel assembly is in accordance with Figure 3.7.13-1 in the accompanying LCO prior to storage in Region 2. Once a fuel assembly has been verified to be within the acceptable range of Figure 3.7.13-1, further verifications are no longer required since the initial enrichment or burnup will not adversely change. For fuel assemblies in the unacceptable range of Figure 3.7.13-1, performance of this SR will ensure compliance with Specification 4.3.1.1.

Though not required for this LCO, this SR must also be performed after completion of fuel movement into Region 2 to exit the Applicability of LCO 3.7.12.

REFERENCES

1. UFSAR, Section 9.1.2.
2. Westinghouse, "Criticality Analysis of the R.E. Ginna Nuclear Power Plant Fresh and Spent Fuel Racks, and Consolidated Rod Storage Canisters," dated June 1994.
3. ANSI N16.1-1975, "American National Standard for Nuclear Criticality Safety in Operations with Fissionable Materials Outside Reactors."

(continued)

BASES

REFERENCES (continued)

4. Letter from B.K. Grimes, NRC, to All Power Reactor Licensees, Subject: "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," dated April 14, 1978.

5. UFSAR, Section 15.7.3.

(continued)

Spent Fuel Storage Racks

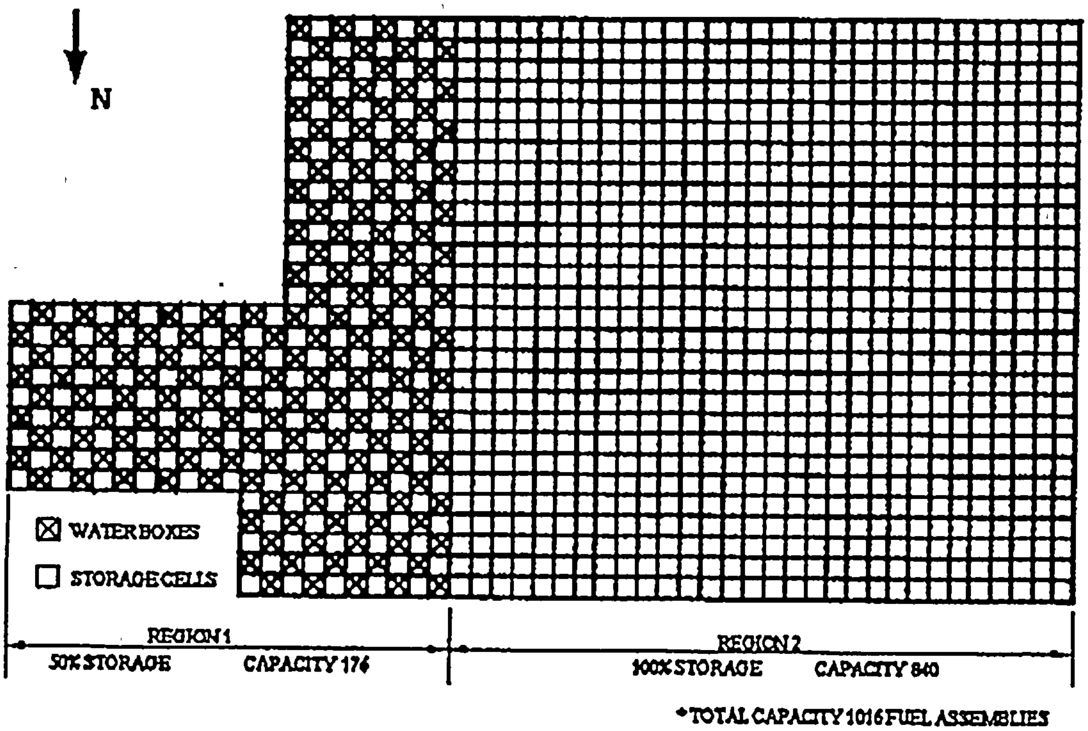


Figure B 3.7.13-1
Spent Fuel Pool

B 3.7 PLANT SYSTEMS

B 3.7.14 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator (SG) tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes can be observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and Design Basis accidents (DBAs).

This limit is based on an activity value that might be expected from a 0.1 gpm tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of 1.0 μCi/gm (LCO 3.4.16, "RCS Specific Activity"). A steam line break (SLB) is assumed to result in the release of the noble gas and iodine activity contained in the SG inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives (i.e., < 20 hours). I-131, with a half life of 8.04 days, concentrates faster than it decays, but does not reach equilibrium because of blowdown and other losses.

With the specified activity limit, the resultant 2 hour thyroid dose to a person at the exclusion area boundary (EAB) would be approximately 10 rem if the main steam safety valves (MSSVs) were left open for 2 hours following a trip from full power. Operating a plant at the allowable limits could result in a 2 hour EAB exposure of a small fraction of the 10 CFR 100 (Ref. 1) limits.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The accident analysis of the SLB, (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological consequences of the postulated accident. The accident analysis, based on this and other assumptions, shows that the radiological consequences of an SLB do not exceed a small fraction of the plant EAB limits (Ref. 1) for whole body and thyroid dose rates.

With the loss of offsite power, the remaining SG is available for core decay heat dissipation by venting steam to the atmosphere through the MSSVs and steam generator atmospheric relief valve (ARV). The Auxiliary Feedwater System supplies the necessary makeup to the SG. Venting continues until the reactor coolant temperature and pressure have decreased sufficiently for the Residual Heat Removal System to complete the cooldown.

In the evaluation of the radiological consequences of this accident, the activity released from the SG connected to the failed steam line is assumed to be released directly to the environment within 60 seconds. The unaffected SG is assumed to discharge steam and any entrained activity through the MSSVs and ARV for the initial two hours of the event. Primary coolant was assumed to be 3.0 μCi/gm for this analysis based on previously allowed limits which is a factor of three greater than current limits specified in LCO 3.4.16. Since no credit is taken in the analysis for activity plateout or retention, the resultant radiological consequences represent a conservative estimate of the potential integrated dose due to the postulated steam line failure.

Secondary specific activity limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

The specific activity of the secondary coolant is required to be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131 to limit the radiological consequences of a DBA to a small fraction of the required limit (Ref. 1).

(continued)

BASES

LCO (continued)	Monitoring the specific activity of the secondary coolant ensures that when secondary specific activity limits are exceeded, appropriate actions are taken in a timely manner to place the plant in an operational MODE that would minimize the radiological consequences of a DBA.
APPLICABILITY	In MODES 1, 2, 3, and 4, the limits on secondary specific activity apply due to the potential for secondary steam releases to the atmosphere from a SLB. In MODES 5 and 6, the SGs are not being used for heat removal. Both the RCS and SGs are depressurized, and primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.
ACTIONS	<u>A.1 and A.2</u> DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant, is an indication of a problem in the RCS and contributes to increased post accident doses. If the secondary specific activity is not within limits the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1

This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131, confirms the validity of the safety analysis assumptions as to the source terms in post accident releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE. The 31 day Frequency is based on the detection of increasing trends of the level of DOSE EQUIVALENT I-131, and allows for appropriate action to be taken to maintain levels below the LCO limit.

REFERENCES

1. 10 CFR 100.11.

2. Letter from D. M. Crutchfield, NRC, to J.E. Maier, RG&E, Subject: "SEP Topic, XV-2, Spectrum of Steam System Piping Failures Inside and Outside Containment; XV-12, Spectrum of Rod Ejection Accidents; XV-16, Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment; XV-17, Steam Generator Tube Failure; and XV-20, Radiological Consequences of Fuel Damaging Accidents - R.E. Ginna," dated September 24, 1981.

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources – MODES 1, 2, 3, and 4

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. One qualified independent offsite power circuit connected between the offsite transmission network and each of the onsite 480 V safeguards buses required by LCO 3.8.9, "Distribution Subsystems – MODES 1, 2, 3, and 4"; and

b. Two emergency diesel generators (DGs) capable of supplying their respective onsite 480 V safeguards buses required by LCO 3.8.9.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Offsite power to one or more 480 V safeguards bus(es) inoperable.	A.1	Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition A concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	A.2	Restore offsite circuit to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One DG inoperable.	B.1	Perform SR 3.8.1.1 for the offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND		
	B.2	Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.3.1	Determine OPERABLE DG is not inoperable due to common cause failure.	24 hours
	OR		
	B.3.2	Perform SR 3.8.1.2 for OPERABLE DG.	24 hours
	AND		
	B.4	Restore DG to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Offsite power to one or more 480 V safeguards bus(es) inoperable. AND One DG inoperable.	-----------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems — MODES 1, 2, 3, and 4," when Condition C is entered with no AC power source to one distribution train. ----------------------------	
	C.1 Restore required offsite circuit to OPERABLE status.	12 hours
	OR	
	C.2 Restore DG to OPERABLE status.	12 hours
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Be in MODE 5.	36 hours
E. Two DGs inoperable.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for the offsite circuit to each of the 480 V safeguards buses.	7 days
SR 3.8.1.2	-----------------NOTES-------------------- 1. Performance of SR 3.8.1.9 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. -- Verify each DG starts from standby conditions and achieves rated voltage and frequency.	31 days
SR 3.8.1.3	------------------NOTES------------------ 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.2 or SR 3.8.1.9. -- Verify each DG is synchronized and loaded and operates for $\geq$ 60 minutes and < 120 minutes at a load $\geq$ 1950 kW and < 2250 kW.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.4	Verify the fuel oil level in each day tank.	31 days
SR 3.8.1.5	Verify the DG fuel oil transfer system operates to transfer fuel oil from each storage tank to the associated day tank.	31 days
SR 3.8.1.6	Verify transfer of AC power sources from the 50/50 mode to the 100/0 mode and 0/100 mode.	24 months
SR 3.8.1.7	-------------------NOTES------------------ 1. This Surveillance shall not be performed in MODE 1, 2, 3, or 4. 2. Credit may be taken for unplanned events that satisfy this SR. --- Verify each DG does not trip during and following a load rejection of ≥ 295 kW.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.8	------------------NOTES------------------ 1. This Surveillance shall not be performed in MODE 1, 2, 3, or 4. 2. Credit may be taken for unplanned events that satisfy this SR. --- Verify each DG automatic trips are bypassed on an actual or simulated safety injection (SI) signal except: a. Engine overspeed; b. Low lube oil pressure; and c. Start failure (overcrank) relay.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	-------------------NOTES------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, 3, or 4. 3. Credit may be taken for unplanned events that satisfy this SR. -- Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated SI actuation signal: a. De-energization of 480 V safeguards buses; b. Load shedding from 480 V safeguards buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads, 2. energizes auto-connected emergency loads through the load sequencer, and 3. supplies permanently and auto-connected emergency loads for ≥ 5 minutes.	24 months

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources — MODES 5 and 6

LCO 3.8.2 The following AC electrical power sources shall be OPERABLE:

a. One qualified independent offsite power circuit connected between the offsite transmission network and each of the onsite 480 V safeguard buses required by LCO 3.8.10, "Distribution Systems — MODES 5 and 6"; and

b. One emergency diesel generator (DG) capable of supplying one train of the onsite 480 V safeguard bus(es) required by LCO 3.8.10.

APPLICABILITY: MODES 5 and 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Offsite power to one or more required 480 V safeguards bus(es) inoperable.	------------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.10, with one required train de-energized as a result of Condition A. ----------------------------	
	A.1 Declare affected required feature(s) inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies.	
	<u>AND</u>	(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.3 Initiate action to suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>	
	A.2.4 Initiate action to restore required offsite power circuit to OPERABLE status.	Immediately
B. DG to the required 480 V safeguards bus(es) inoperable.	B.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	B.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	B.3 Initiate action to suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>	
	B.4 Initiate action to restore required DG to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.2.1	For AC sources required to be OPERABLE, the following SRs are applicable: SR 3.8.1.1 SR 3.8.1.4 SR 3.8.1.2 SR 3.8.1.5	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Diesel Fuel Oil

LCO 3.8.3 The stored diesel fuel oil shall be within limits for each required emergency diesel generator (DG).

APPLICABILITY: MODES 1, 2, 3, and 4,
When associated DG is required to be OPERABLE by LCO 3.8.2, "AC Sources — MODES 5 and 6."

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each DG.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required DGs with onsite fuel oil supply not within limit.	A.1 Restore fuel oil level to within limit.	12 hours
B. One or more required DGs with stored fuel oil total particulates not within limit.	B.1 Restore fuel oil total particulates within limit.	7 days
C. One or more DGs with new fuel oil properties not within limits.	C.1 Restore stored fuel oil properties within limits.	30 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time not met. OR One or more required DGs diesel fuel oil not within limits for reasons other than Condition A, B, or C.	D.1 Declare associated DG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify each fuel oil storage tank contains ≥ 5000 gal of diesel fuel oil for each required DG.	31 days
SR 3.8.3.2	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources – MODES 1, 2, 3, and 4

LCO 3.8.4 The Train A and Train B DC electrical power sources shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One DC electrical power source inoperable.	A.1	Restore DC electrical power source to OPERABLE status.	2 hours
B. Required Action and Associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in Mode 5.	36 hours
C. Both DC electrical power sources inoperable.	C.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage is ≥ 129 V on float charge.	7 days
SR 3.8.4.2	-------------------NOTES------------------- 1. SR 3.8.4.3 may be performed in lieu of SR 3.8.4.2. 2. This Surveillance shall not be performed in MODE 1, 2, 3, or 4. --- Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.3	------------------NOTE------------------ This Surveillance shall not be performed in MODE 1, 2, 3, or 4. -- Verify battery capacity is ≥ 80% of the manufacturer's rating when subjected to a performance discharge test.	60 months <u>AND</u> 12 months when battery shows degradation, or has reached 85% of expected life with capacity < 100% of manufacturer's rating <u>AND</u> 24 months when battery has reached 85% of the expected life with capacity ≥ 100% of manufacturer's rating

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 DC Sources - MODES 5 and 6

LCO 3.8.5 DC electrical power sources shall be OPERABLE to support the DC electrical power distribution subsystem required by LCO 3.8.10, "Distribution Systems - MODES 5 and 6."

APPLICABILITY: MODES 5 and 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required DC electrical power source(s) inoperable.	A.1 Declare affected required feature(s) inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	A.2.3 Initiate action to suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>	
	A.2.4 Initiate action to restore required DC electrical power source(s) to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.5.1	For DC sources required to be OPERABLE, SR 3.8.4.1 is applicable.	In accordance with applicable SR

3.8 ELECTRICAL POWER SYSTEMS

3.8.6 Battery Cell Parameters

LCO 3.8.6 Battery cell parameters for Train A and Train B batteries shall be within limits.

APPLICABILITY: MODES 1, 2, 3, and 4,
When associated DC electrical power sources are required to be OPERABLE by LCO 3.8.5, "DC Sources—MODES 5 and 6."

ACTIONS

-----------------------------------NOTE-----------------------------------
Separate Condition entry is allowed for each battery.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more batteries with one or more battery cell parameters not within limits.	A.1 Declare associated battery inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.6.1	Verify electrolyte level of each connected battery cell is above the top of the plates and not overflowing.	31 days
SR 3.8.6.2	Verify the float voltage of each connected battery cell is > 2.07 V.	31 days
SR 3.8.6.3	Verify specific gravity of the designated pilot cell in each battery is ≥ 1.188 for Battery A and ≥ 1.192 for Battery B.	31 days
SR 3.8.6.4	Verify average electrolyte temperature of the designated pilot cell in each battery is ≥ 55°F.	31 days
SR 3.8.6.5	Verify average electrolyte temperature of every fifth cell of each battery is ≥ 55°F.	92 days
SR 3.8.6.6	Verify specific gravity of each connected battery cell is: a. Not more than 0.020 below average of all connected cells, and b. Average of all connected cells is ≥ 1.188 for Battery A and ≥ 1.192 for Battery B.	92 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 AC Instrument Bus Sources – MODES 1, 2, 3, and 4

LCO 3.8.7 The following AC instrument bus power sources shall be OPERABLE:

a. Inverters for Instrument Buses A and C; and

b. Class 1E constant voltage transformer (CVT) for Instrument Bus B.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One inverter inoperable.	A.1 Power AC instrument bus from its Class 1E or non-Class 1E CVT.	2 hours
	<u>AND</u>	
	A.2 Power AC instrument bus from its Class 1E CVT.	24 hours
	<u>AND</u>	
	A.3 Restore inverter to OPERABLE status.	72 hours
B. Class 1E CVT for AC Instrument Bus B inoperable.	B.1 Power AC Instrument Bus B from its non-Class 1E CVT.	2 hours
	<u>AND</u>	
	B.2 Restore Class 1E CVT for AC Instrument Bus B to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours
D. Two or more required instrument bus sources inoperable.	D.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct static switch alignment to Instrument Bus A and C.	7 days
SR 3.8.7.2	Verify correct Class 1E CVT alignment to Instrument Bus B.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.8 AC Instrument Bus Sources — MODES 5 and 6

LCO 3.8.8 AC instrument bus power sources shall be OPERABLE to support the onsite Class 1E AC instrument bus electrical power distribution subsystem required by LCO 3.8.10, "Distribution Systems — MODES 5 and 6."

APPLICABILITY: MODES 5 and 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required AC instrument bus power source(s) inoperable.	A.1 Declare affected required feature(s) inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	A.2.3 Initiate action to suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>	
	A.2.4 Initiate action to restore required AC instrument bus power source(s) to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct static switch alignment to required AC instrument bus(es).	7 days
SR 3.8.8.2	Verify correct Class 1E CVT alignment to the required AC instrument bus.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems – MODES 1, 2, 3, and 4

LCO 3.8.9 Train A and Train B of the following electrical power distribution subsystems shall be OPERABLE:

a. AC power;

b. AC instrument bus power; and

c. DC power.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One AC electrical power distribution train inoperable.	A.1	Restore AC electrical power distribution train to OPERABLE status.	8 hours
B. One AC instrument bus electrical power distribution train inoperable.	B.1	Restore AC instrument bus electrical power distribution train to OPERABLE status.	2 hours
C. One DC electrical power distribution train inoperable.	C.1	Restore DC electrical power distribution train to OPERABLE status.	2 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Conditions A, B, or C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours
E. Two trains with inoperable electrical power distribution subsystems that result in a loss of safety function.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.8.9.1 Verify correct breaker alignments and voltage to required electrical power trains.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.10 Distribution Systems – MODES 5 and 6

LCO 3.8.10 The necessary trains(s) of the following electrical power distribution subsystems shall be OPERABLE to support equipment required to be OPERABLE:

a. AC power;

b. AC instrument bus power; and

c. DC power.

APPLICABILITY: MODES 5 and 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required electrical power distribution train(s) inoperable.	A.1 Declare associated supported required feature(s) inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	A.2.3 Initiate action to suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.4 Initiate actions to restore required electrical power distribution train(s) to OPERABLE status.	Immediately
	AND	
	A.2.5 Declare associated required residual heat removal loop(s) inoperable and not in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.10.1	Verify correct breaker alignments and voltage to required electrical power distribution trains.	7 days

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—MODES 1, 2, 3, and 4

BASES

BACKGROUND

A source of electrical power is required for most safety related and nonessential active components. Two sources of electrical power are available, alternating current (AC) and direct current (DC). Separate distribution systems are developed for each of these electrical power sources which are further divided and organized based on voltage considerations and safety classification. This LCO is provided to specify the minimum sources of AC power which are required to supply the 480 V safeguards buses and associated distribution subsystem during MODES 1, 2, 3, and 4.

The plant AC sources consist of an independent offsite power source and the onsite standby emergency power source (Ref. 1). Atomic Industrial Forum (AIF) GDC 39 (Ref. 2) requires emergency power sources be provided and designed with adequate independence, redundancy, capacity, and testability to permit the functioning of the Engineered Safety Features (ESF) and protection systems. The offsite and onsite AC sources can each supply power to 480 V safeguards buses to ensure that reliable power is available during any normal or emergency mode of plant operation. The 480 V safeguards buses are divided into redundant trains so that the loss of any one train does not prevent the minimum safety functions from being performed. Safeguards Buses 14 and 18 are associated with Train A and safeguards Buses 16 and 17 are associated with Train B. Since only the onsite standby power source is classified as Class 1E, the offsite power source is not required to be separated into redundant trains.

(continued)

BASES

BACKGROUND (continued)

The independent offsite power source consists of breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite 480 V safeguards buses. The independent offsite power source essentially begins from two station auxiliary transformers (SAT 12A and 12B) each supplied from an independent transmission line emanating from separate switchyards (see Figure B 3.8.1-1). SAT 12A is connected to the 34.5 kV transmission system (circuit 751) and SAT 12B is connected to the plant 115 kV switchyard (circuit 767). The SATs may be configured in the following modes:

a. SAT 12A (or SAT 12B) supplies safeguards Buses 16 and 17 and SAT 12B (or SAT 12A) supplies safeguards Buses 14 and 18 (50/50 mode);

b. SAT 12A supplies all safeguards Buses (0/100 mode); or

c. SAT 12B supplies all safeguards Buses (100/0 mode).

The preferred configuration is the 50/50 mode; however, all three modes of operation meet applicable design requirements for normal operation (Ref. 1). Offsite power can also be provided during an emergency through the plant auxiliary transformer 11 by backfeeding from the 115 kV transmission system and main transformer.

SATs 12A and 12B are each connected to two non-Class 1E, 4.16 kV buses (12A and 12B). The 4.16 kV Bus 12A feeds the Class 1E loads on the 480 V safeguards Buses 14 and 18 and 4.16 kV Bus 12B feeds the Class 1E loads on the 480 V safeguards Buses 16 and 17 (see Figure B 3.8.1-1). Loss of power to any of the safeguards buses, as a result of inoperable offsite circuit component(s), is a loss of offsite power. The offsite power source ends after the feeder breaker supplying each 480 V safeguards bus.

(continued)

BASES

BACKGROUND (continued)

The onsite standby power sources consist of two 1950 kW continuous rating emergency diesel generators (DGs) connected to the safeguards buses to supply emergency power in the event of loss of all other AC power. The DGs are located in separate rooms in a Seismic Category I structure located adjacent to the northeast wall of the Turbine Building. Each DG room has its own ventilation system. The ventilation system is designed to maintain the DG room between 60°F and 104°F and to remove any hydrocarbon gases in the room (Ref. 3). Each ventilation system consists of two fans and associated ductwork and dampers that fail open on loss of instrument air and control power. One fan is designed to start on DG actuation with a second fan designed to start when the room temperature reaches 90°F. The second fan's discharge air flow is directed to the DG control panel and has a delayed start to prevent potentially freezing the cooling water jacket piping during cold weather conditions.

The DGs utilize an air motor for starting. The air motor is supplied by two receivers which provide sufficient air for five DG starts before requiring a recharge of the receivers. The DGs are supplied by separate fuel oil day tanks which can be cross-tied if required. Additional fuel oil can be transferred from redundant underground fuel oil storage tanks. A dedicated fuel oil transfer pump is used for this transfer. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve, or tank, to result in the loss of more than one DG.

DG A is dedicated to safeguards Buses 14 and 18 and DG B is dedicated to safeguards Buses 16 and 17. A DG starts automatically on a safety injection (SI) signal or on an undervoltage signal on its corresponding 480 V buses (refer to LCO 3.3.4, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation"). In the event of only an SI signal, the DGs automatically start and operate in the standby mode without tying to the safeguards buses.

(continued)

BASES

BACKGROUND (continued)

In the event of loss of offsite power, or abnormal offsite power where offsite power is tripped as a consequence of bus undervoltage or degraded voltage, the DGs automatically start and tie to their respective buses. All bus loads except for the containment spray (CS) pump, component cooling water (CCW) pump and safety related motor control centers are tripped upon actuation of the undervoltage relays. This is independent of or coincident with an SI signal. Once the undervoltage relay resets independent of a SI signal, the operator may manually connect loads onto the bus(es). During a coincident SI signal, the CCW pump is also tripped and loads are sequentially connected to their respective buses by the automatic load sequencer.

In the event of loss of offsite power to only one safeguards bus in a train, the DG will automatically start and tie only to the affected bus. During a coincident SI signal, the normal feed breaker on the second bus on the affected train will be tripped by the undervoltage relay on the failed bus causing the DG to automatically tie to both buses. This condition will then actuate the automatic load sequencer.

In the event of a loss of offsite power and a coincident SI signal, the electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA). Certain required plant loads are returned to service in a predetermined sequence by the automatic load sequencer in order to prevent overloading the DG during the start process. Within approximately 1 minute after the initiating signal is received, all loads needed to recover the plant or maintain it in a safe condition are returned to service.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses (Refs. 4 and 5) assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, "Power Distribution Limits;" Section 3.4, "Reactor Coolant System (RCS);" and Section 3.6, "Containment Systems."

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This results in maintaining at least one train of the onsite standby power or offsite AC sources OPERABLE in the event of:

a. An assumed loss of all AC offsite power or all onsite standby AC power; and

b. A worst case single failure.

In the event of a DBA, the OPERABILITY requirements of the AC electrical power sources ensures that one train of offsite or onsite standby AC power is available with:

a. An assumed loss of all offsite power; and

b. A worst case single failure (including the loss of one train of onsite standby power).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In general, the accident analyses assume that all offsite power is lost at the time of the initiating event except where the availability of offsite power provides worst case conditions (e.g., steam line break with continued operation of the reactor coolant pumps). The availability of redundant offsite power sources (i.e., circuits 751 and 767) helps to reduce the potential to lose all offsite power. Providing redundant sources of offsite power also ensures that at least one AC power source is available if all onsite standby AC power is unavailable coincident with a single failure of one offsite power source during non accident conditions. In the event the plant is in the 100/0 or 0/100 mode, a redundant source of offsite power can be obtained by backfeeding through the main transformer using a flexible connection that can be tied into the plant auxiliary transformer 11. The plant can survive on the available battery power, alternate power sources, and turbine driven Auxiliary Feedwater pump during the estimated 8 hours required to provide this power transfer (Ref. 1). Therefore, the requirements of GDC 17 (Ref. 6) can be met at all times.

The DGs are designed to operate following a DBA or anticipated operational occurrence (AOO) until offsite power can be restored. An AOO is defined as a Condition 2 event in Reference 7 (i.e., events which can be expected to occur during a calendar year with moderate frequency). The DGs are required to start within 10 seconds and begin loading. The DGs can begin receiving up to 30% of design loads after the 10 second start time and can accept 100% of design loads within 30 seconds. The DGs are manually loaded if only an undervoltage signal is present and load sequenced if a coincident undervoltage and SI signal is present. The loads are sequenced as follows (assume SI signal at 0 seconds):

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

DG Load	DG A Time	DG B Time
480V safeguards buses and CS pumps	10	10
SI pump A and B	15	15
SI pump C	20	22
Residual heat removal pump	25	27
Selected service water pump	30	32
First containment recirculation fan cooler	35	37
Second containment recirculation fan cooler	40	42
Motor driven auxiliary feedwater pump	45	47

Since the DGs must start and begin loading within 10 seconds, only one air start must be available in the air receivers as assumed in the accident analyses. The long term operation of the DGs (until offsite power is restored) is discussed in LCO 3.8.3, "Diesel Fuel Oil."

The AC sources satisfy Criterion 3 of NRC Policy Statement.

LCO

One qualified independent offsite power circuit connected between the offsite transmission network and the onsite 480 V safeguards buses and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA.

An OPERABLE qualified independent offsite power circuit is one that is capable of maintaining rated voltage, and accepting required loads during an accident, while connected to the 480 V safeguards buses required by LCO 3.8.9, "Distribution Subsystems - MODES 1, 2, 3, and 4." Power from either offsite power circuit 751 or 767 satisfies this requirement.

A DG is considered OPERABLE when:

a. The DG is capable of starting, accelerating to rated speed and voltage, and connecting to its respective 480 V safeguards buses on detection of bus undervoltage within 10 seconds;

(continued)

BASES

LCO (continued)

b. All loads on each 480 V safeguards bus except for the safety related motor control centers, CCW pump, and CS pump are capable of being tripped on an undervoltage signal (CCW pump must be capable of being tripped on coincident SI and undervoltage signal);

c. The DG is capable of accepting required loads both manually and within the assumed loading sequence intervals following a coincident SI and undervoltage signal, and continue to operate until offsite power can be restored to the safeguards bus (i.e., 40 hours);

d. The DG day tank is available to provide fuel oil for ≥ 1 hour at 110% design loads;

e. The fuel oil transfer pump from the fuel oil storage tank to the associated day tank is OPERABLE including all required piping, valves, and instrumentation (long-term fuel oil supplies are addressed by LCO 3.8.3, "Diesel Fuel Oil"); and

f. A ventilation train consisting of at least one of two fans and the associated ductwork and dampers is OPERABLE.

The AC sources in one train must be separate and independent of the AC sources in the other train. For the DGs, separation and independence must be complete assuming a single active failure. For the independent offsite power source, separation and independence are to the extent practical (i.e., operation is preferred in the 50/50 mode, but may also exist in the 100/0 or 0/100 mode).

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

(continued)

BASES

APPLICABILITY (continued)

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources - MODES 5 and 6."

ACTIONS

A.1 and A.2

With offsite power to one or more 480V safeguard bus(es) inoperable, assurance must be provided that a coincident single failure will not result in a complete loss of required safety features. If the redundant safety feature to the component or train affected by the loss of offsite power is also unavailable, the assumption that two complete safety trains are OPERABLE may no longer exist. As an example, if offsite power were unavailable to 480 V Bus 14, DG A could supply the necessary power to the bus. If residual heat removal pump (RHR) B (supplied power by Bus 16) were inoperable at the same time, or at any time after the loss of offsite power to Bus 14, a loss of redundant required safety features exists since a failure of DG A would result in the loss of emergency core cooling. Therefore, RHR pump A on Bus 14 would have to be declared inoperable within 12 hours after RHR pump B and offsite power to Bus 14 were declared unavailable.

The Completion Time of 12 hours as provided by Required Action A.1 to declare the required safety features inoperable is based on the fact that it is less than the Completion Time for restoring OPERABILITY of the offsite power circuit and all safety features affected by the loss of the 480 V bus. A shorter Completion Time is provided since the required safety features have been potentially degraded by the loss of offsite power (i.e., using the same example as above, the 72 hour Completion Time for restoring RHR pump B was developed assuming that RHR pump A had both offsite and onsite standby emergency power available). Therefore, a penalty is assessed to only allow 12 hours in this configuration.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

The Completion Time for Required Action A.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time is an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that:

a. There is no offsite power available to one or more 480 V safeguards bus; and

b. A redundant required feature is inoperable on a second 480 V safeguards bus.

If at any time during the existence of Condition A, a redundant required feature becomes inoperable, this Completion Time begins to be tracked. Required Action A.1 can be exited if the inoperable DG or the required feature on the OPERABLE DG is restored to OPERABLE status.

The level of degradation during Condition A means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite standby AC sources have not been degraded. This level of degradation generally corresponds to either:

a. Loss of offsite power sources to SAT 12A and/or SAT 12B;

b. Failure of SAT 12A or 12B or 4.16 kV Bus 12A or 12B; or

c. Failure of a station service transformer supplying a 480 V safeguards bus.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

With a total loss of the offsite power sources to SAT 12A and 12B, the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident for either train. With loss of offsite power to SAT 12A or 12B, failure of SAT 12A or 12B, or failure of Bus 12A or 12B, the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident for a single AC electrical train. With a failure of a station service transformer, the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the consequences of an accident for one 480 V safeguards bus in one AC electrical train. In all cases, sufficient onsite AC sources are available to maintain the plant in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 72 hour Completion Time provides a period of time to effect restoration of the offsite circuit commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

B.1

With one DG inoperable, it is necessary to verify the availability of the offsite circuit to each of the affected 480 V safeguards buses on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met (i.e., Condition D would not apply). However, if a circuit fails to pass SR 3.8.1.1, it is inoperable and Condition C would be entered. The Completion Time of 1 hour to perform SR 3.8.1.1 is based on the importance of this verification to ensure that offsite power is available to the affected bus. The Frequency of once per 8 hours thereafter is based on the alarms and indications of breaker status that are available in the control room.

(continued)

BASES

ACTIONS (continued)

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of a safety feature. These features are designed with redundant safety related trains which are supplied power from separate and independent onsite power sources. If one onsite power source is inoperable, it must be assured that the redundant safety related train supplied by the OPERABLE DG is available to provide the necessary safety function.

The Completion Time of 4 hours for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time is an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other train (Train A or Train B) is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature supported by the OPERABLE DG subsequently becomes inoperable, this Completion Time would begin to be tracked. Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are supplied power by the OPERABLE DG, results in starting the Completion Time for Required Action B.2. In this Condition, the remaining OPERABLE DG and the offsite circuit are adequate to supply electrical power to the onsite 480 V safeguards buses.

(continued)

BASES

ACTIONS

B.2 (continued)

The Completion Time of 4 hours to declare the required safety features inoperable is based on the fact that it is less than the Completion Time for restoring OPERABILITY of the DG and all safety features supported by the DG. A shorter Completion Time is provided since the required safety features have been potentially degraded by the inoperable DG. Therefore, a penalty is assessed to only allow 4 hours in this configuration. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period. Required Action B.2 can be exited if the inoperable DG or the required feature on the OPERABLE DG is restored to OPERABLE status.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of the OPERABLE DG. If it can be determined within 24 hours that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 is not required to be performed. If the cause of inoperability is determined to exist on the other DG, the second DG would be declared inoperable upon discovery and Condition E would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the second DG within 24 hours, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, activities must continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

The 24 hour Completion Time is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG (Ref. 8).

(continued)

BASES

ACTIONS (continued)

B.4

With one inoperable DG, the remaining OPERABLE DG and the offsite circuit are adequate to supply electrical power to the onsite 480 V safeguards buses. The 7 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

C.1

With offsite power to one or more 480 V safeguards bus(es) and one DG inoperable, redundancy is lost in both the offsite and onsite AC electrical power systems. Since power system redundancy is provided by these two diverse sources of power, the AC power sources are only degraded and no loss of safety function has occurred since at least one DG and potentially one offsite AC power source are available. However, the plant is vulnerable to a single failure which could result in the loss of multiple safety functions. Therefore, a Completion Time of 12 hours is provided to either restore the offsite power circuit or the DG to OPERABLE status. This Completion Time is less than that for an inoperable offsite power source or an inoperable DG due to the single failure vulnerability of this configuration.

As discussed in LCO 3.0.6, the AC electrical power distribution subsystem ACTIONS would not be entered even if all AC sources to either train were inoperable, resulting in de-energization. Therefore, the Required Actions of this Condition are modified by a Note which states that the Required Actions of LCO 3.8.9, "Distribution Systems-MODES 1, 2, 3, and 4" must also be immediately entered with no AC power source to one distribution train. This allows Condition C to provide requirements for the loss of an offsite power circuit and one DG, without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

If both DGs are inoperable, a loss of safety function would exist if offsite power were unavailable; therefore, LCO 3.0.3 must be entered.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function (Ref. 2). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions).

SR 3.8.1.1

This SR ensures proper circuit continuity for the independent offsite power source to each of the onsite 480 V safeguards buses and availability of offsite AC electrical power. Checking breaker alignment and indicated power availability verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their qualified power source. The Frequency of 7 days is adequate since breaker position is not likely to change without the operators knowledge and because alarms and indications of breaker status are available in the control room.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.2

This SR verifies that each DG starts from standby conditions and achieves rated voltage and frequency. This ensures the availability of the DG to mitigate DBAs and transients and to maintain the plant in a safe shutdown condition. The DG voltage control may be either in manual or automatic during the performance of this SR. The Frequency of 31 days is adequate to provide assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

This SR is modified by two Notes. Note 1 indicates that performance of SR 3.8.1.9 satisfies this SR since SR 3.8.1.9 is a complete test of the DG. The second Note states that all DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. This minimizes the wear on moving parts that do not get lubricated when the engine is not running.

SR 3.8.1.3

This SR verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures. A maximum run time not to exceed 120 minutes minimizes the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.85 lagging and 0.95 lagging. The upper load band limit of 2250 kW is provided to avoid routine overloading of the DG which may result in more frequent inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. The lower load band limit is the expected maximum load following a DBA.

In addition to verifying the DG capability for synchronizing with the offsite electrical system and accepting loads, the DG ventilation system should also be verified during this surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

The Frequency of 31 days is adequate to provide assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients outside the load band (e.g., due to changing bus loads), do not invalidate this test. Similarly, momentary power factor transients above or below the administrative limit do not invalidate the test. Note 3 indicates that this Surveillance shall be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful performance of SR 3.8.1.2 or SR 3.8.1.9 must precede this surveillance to prevent unnecessary starts of the DGs.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in each day tank is at or above the level at which fuel oil is automatically added when the fuel oil transfer pump is in auto and the DG is operating. This level ensures adequate fuel oil for a minimum of 1 hour of DG operation at 110% of full load. This is equivalent to a day tank level of 8.25 inches above the tank suction line.

The Frequency of 31 days is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and operators would be aware of any large uses of fuel oil during this period.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.5

This SR demonstrates that each DG fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of the DGs. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic or manual fuel transfer systems are OPERABLE.

The Frequency of 31 days is adequate to provide assurance of DG OPERABILITY, since the design of the fuel oil transfer system is such that pumps operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day tanks during or following DG operation.

SR 3.8.1.6

This SR involves the transfer of the 480 V safeguards bus power supply from the 50/50 mode to the 100/0 mode and 0/100 mode which demonstrates the OPERABILITY of the alternate circuit distribution network to power the required loads. The Frequency of 24 months is based on engineering judgment, taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.7

This SR verifies that each DG does not trip during and following a load rejection of ≥ 295 kW. Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This SR demonstrates the DG load response characteristics and capability to reject the largest single load on the buses supplied by the DG (i.e., a safety injection pump).

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≤ 0.9 lagging. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

The Frequency of 24 months is based on engineering judgement, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The first Note states that this Surveillance shall not be performed in MODE 1, 2, 3, or 4. The reason for the Note is that during operation in these MODES, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. The second Note acknowledges that credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.8

This SR demonstrates that DG noncritical protective functions (e.g., overcurrent, reverse power, local stop pushbutton) are bypassed on an actual or simulated SI actuation signal, and critical protective functions (engine overspeed, low lube oil pressure, and start failure (overcrank) relay) trip the DG to avert substantial damage to the DG. The noncritical trips are bypassed during DBAs but still provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The Frequency of 24 months is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

This SR is modified by two Notes. The first Note states that this Surveillance shall not be performed in MODE 1, 2, 3, or 4. The reason for the Note is that performing the Surveillance would remove a required DG from service which is undesirable in these MODES. The second Note acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.9

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

This SR demonstrates the DG operation during an actual or simulated loss of offsite power signal in conjunction with an actual or simulated SI actuation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 24 months is based on engineering judgement, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by three Notes. Note 1 states that all DG starts may be preceded by an engine prelube period which is intended to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine lube oil continuously circulated and temperature maintained consistent with manufacturer recommendations for the DGs. Note 2 states that this Surveillance shall not be performed in MODE 1, 2, 3, or 4 since performing the Surveillance during these MODES would remove a required offsite circuit from service, cause perturbations to the electrical distribution systems, and challenge safety systems. Note 3 acknowledges that credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Chapter 8.
2. Atomic Industrial Forum (AIF) GDC 39, Issued for comment July 10, 1967.
3. UFSAR, Section 9.4.9.5.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. 10 CFR 50, Appendix A, GDC 17.
7. "American National Standard, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," N18.2-1973.
8. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.

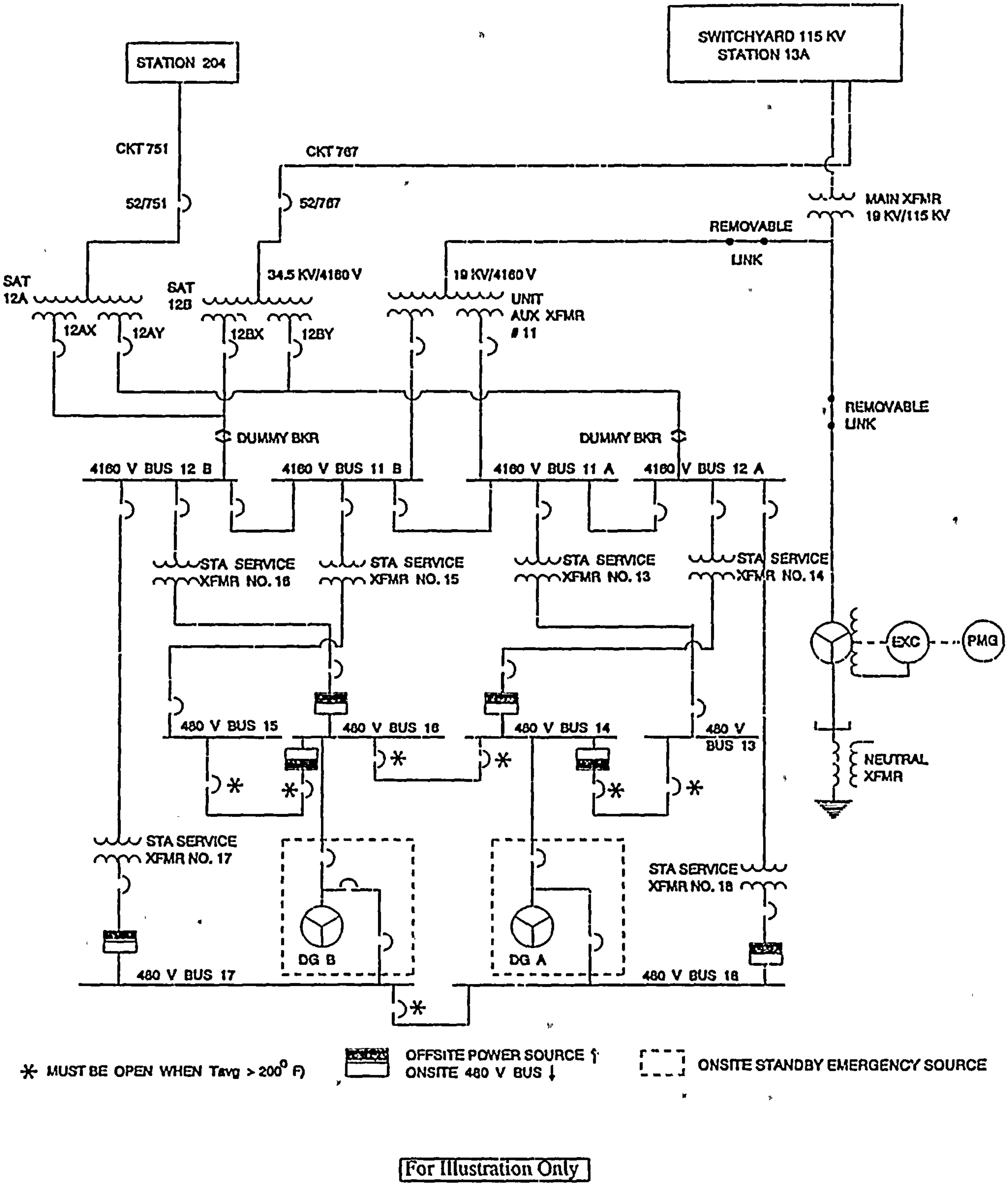


Figure B 3.8.1-1

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources — MODES 5 and 6

BASES

BACKGROUND

The Background section for Bases 3.8.1, "AC Sources — MODES 1, 2, 3, and 4" is applicable to theses Bases, with the following modifications.

In MODE 5 or 6 the minimum required AC sources may be reduced since less energy is retained within the reactor coolant system than during higher MODES. Also, a significant number of required testing and maintenance activities must be performed under these conditions such that equipment and systems, including the AC power sources, must be removed from service. The minimum required AC sources is based on the requirements of LCO 3.8.10, "Distribution Systems — MODES 5 and 6."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC electrical power sources during MODES 5 and 6 ensures that:

a. Systems needed to mitigate a fuel handling accident are available; and

b. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available;

In general, when the plant is shut down, the Technical Specifications requirements ensure that the plant has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. Therefore, the OPERABILITY of the AC electrical power sources ensures that one train of the onsite power or offsite AC sources are OPERABLE in the event of:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. An assumed loss of all offsite AC power;

b. An assumed loss of all onsite standby AC power; or

c. A worst case single failure.

This reduction in required AC sources is allowed because many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary (reactor coolant temperature and pressure) and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and result in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCOs for the systems required in MODES 5 and 6.

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) for systems assumed to function during an event.

In the event of an accident while in MODE 5 or 6 this LCO ensures the capability to support systems necessary to mitigate the postulated events during shutdown, assuming either a loss of all offsite power or a loss of all onsite diesel generator (DG) power.

The AC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

One qualified independent offsite power circuit supplying the associated AC electrical power distribution subsystem required to be OPERABLE by LCO 3.8.10, "Distribution Systems—MODES 5 and 6," ensures that all required loads are powered from offsite power. An OPERABLE DG, capable of supporting the distribution system required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the independent offsite power circuit. Together, OPERABILITY of the required offsite circuit and DG ensures the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

An OPERABLE qualified offsite circuit is one that is capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the 480 V safeguards bus(es). Power from either offsite power circuit 751 or 767, or by backfeeding through auxiliary transformer 11 satisfies this requirement.

(continued)

BASES

LCO (continued)

A DG is considered OPERABLE when:

a. The DG is capable of starting, accelerating to rated speed and voltage, and connecting to its respective 480 V safeguards buses on detection of bus undervoltage within 10 seconds;

b. All loads on each 480 V safeguards bus except for the safety related motor control centers, component cooling water (CCW) pump, and containment spray (CS) pump are capable of being tripped on an undervoltage signal (CCW pump must be capable of being tripped on coincident safety injection (SI) and undervoltage signal);

c. The DG is capable of accepting required loads manually. Since most equipment which receives a SI signal are isolated in these MODES due to maintenance or low temperature overpressure protection concerns, and the DBA of concern (i.e., a fuel handling accident) would not generate a SI signal, manual loading of the DGs will most likely be required. These loads must be capable of being added to the OPERABLE DG within 10 minutes;

d. The DG day tank is available to provide fuel oil for ≥ 1 hour at 110% design loads;

e. The fuel oil transfer pump from the fuel oil storage tank to the associated day tank is OPERABLE including all required piping, valves, and instrumentation (long-term fuel oil supplies are addressed by LCO 3.8.3, "Diesel Fuel Oil"); and

f. A ventilation train consisting of at least one of two fans and the associated ductwork and dampers is OPERABLE.

(continued)

BASES (continued)

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 provide assurance that systems required to mitigate the effects of postulated events and to maintain the plant in the cold shutdown or refueling condition are available.

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1, "AC Sources—MODES 1, 2, 3, and 4."

ACTIONS

A.1

As discussed in LCO 3.0.6, the Distribution System's ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no onsite or offsite AC power to any required 480 V safeguards bus, the ACTIONS for LCO 3.8.10 must also be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite power circuit, whether or not a train is de-energized. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a completely de-energized train.

With offsite power available to one or more required 480 V safeguards bus(es) inoperable, assurance must be provided that there is not a complete loss of required safety features. Although two trains may be required by LCO 3.8.10, one train with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, or operations involving positive reactivity additions. By allowing the option to declare required features inoperable that are not powered from offsite power, appropriate restrictions will be implemented in accordance with the LCO ACTIONS of the affected required features. Required features remaining powered from a qualified offsite power circuit, even if that circuit is considered inoperable because it is not powering other required features, are not declared inoperable by this Required Action.

(continued)

BASES

ACTIONS (continued)

A.2.1, A.2.2, A.2.3, and A.2.4

With the offsite power circuit not available to all required AC electrical trains, the option exists to declare all required features inoperable per Required Action A.1. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. Therefore, immediate suspension of CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions is an acceptable option to Required Action A.1. Performance of Required Actions A.2.1, A.2.2, and A.2.3 shall not preclude completion of movement of a component to a safe position or normal cooldown of the coolant volume for the purpose of system temperature control within established procedures.

It is further required to immediately initiate action to restore the required offsite power AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required offsite power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

B.1, B.2, B.3, and B.4

With the required DG inoperable, the minimum required diversity of AC power sources is not available. Therefore, it is required that CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions be immediately suspended. Performance of Required Action B.1, B.2, and B.3 shall not preclude completion of movement of a component to a safe position or normal cooldown of the coolant volume for the purpose of temperature control within established procedures.

(continued)

BASES

ACTIONS

B.1, B.2, B.3, and B.4 (continued)

It is further required to immediately initiate action to restore the required DG to OPERABLE status and to continue this action until restoration is accomplished in order to provide the necessary AC power redundancy to plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DG should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient redundant power.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

This SR requires the performance of SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in MODES 5 and 6.

This SR precludes requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, precludes de-energizing a required 480 V safeguards bus, and precludes unnecessary transfers of the offsite power source configurations. With limited AC sources available, a single event could compromise both the required circuit and the DG. Therefore, the requirement to perform SR 3.8.1.3, and SR 3.8.1.6 through 3.8.1.9 is suspended. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil

BASES

BACKGROUND

Fuel oil is provided to each emergency diesel generator (DG) by a dedicated 350 gal day tank located near the DG. Each day tank is supplied from an associated 6000 gal underground fuel oil storage tank. Each storage tank provides a minimum fuel oil capacity of 5000 gal. The two storage tanks are sufficient to operate both DGs at design ratings for 24 hours. The total minimum fuel oil capacity also ensures that both DGs can operate for a period of 40 hours while providing for a maximum post loss of coolant accident (LOCA) load demand. The maximum load demand is calculated using the assumption that both DGs are available and is less than the DG design rating. The minimum onsite fuel capacity is sufficient to operate the DGs for longer than 8 hours which is the time required to replenish the onsite supply from outside sources (Ref. 1).

Fuel oil is transferred from each storage tank to the associated day tank by a dedicated fuel oil transfer pump. Each fuel oil transfer pump is powered by a 480 V safeguards bus that is backed by the associated DG. One fuel oil transfer pump has the capability to supply both DGs operating with 110% of their design loads. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve or tank to result in the loss of more than one DG.

All outside tanks, pumps, and piping are located underground to protect them from potential missiles. Heat tracing is provided in the exposed suction piping to the fuel oil pumps in the event that heating is lost in the DG rooms. The heat tracing is thermostatically controlled to maintain the fuel oil in the pipe > 40°F which is above the cloud point temperature of the fuel oil (0°F).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses (Refs. 2 and 3), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, "Power Distribution Limits;" Section 3.4, "Reactor Coolant System (RCS);" and Section 3.6, "Containment Systems." Since diesel fuel oil supports the operation of the standby AC power sources, it satisfies Criterion 3 of the NRC Policy Statement.
LCO	Stored onsite diesel fuel oil is required to have sufficient supply for 40 hours of maximum post-LOCA load demand. It is also required to meet specific standards for quality. This requirement, in conjunction with an ability to obtain replacement fuel oil supplies within 8 hours, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources — MODES 1, 2, 3, and 4," and LCO 3.8.2, "AC Sources — MODES 5 and 6."
APPLICABILITY	The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil supports LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil is required to be within limits in MODES 1, 2, 3 and 4, and when the associated DG is required to be OPERABLE in MODES 5 and 6.

(continued)

BASES (continued)

ACTIONS

A.1

With one or more required DGs with an onsite supply of < 5000 gal of fuel oil, the assumed 40 hour fuel oil supply for a DG is not available. This circumstance may be caused by events, such as full load operation after an inadvertent start with an initial minimum required fuel oil level, or feed and bleed operations, which may be necessitated by increasing fuel oil particulate levels or any number of other oil quality degradations. Required Action A.1 allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of fuel oil to the tank. The Completion Time of 12 hours is considered sufficient to complete restoration of the required level prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity, the fact that actions will be initiated to obtain replenishment, and the low probability of an event during this brief period.

B.1

If one or more DGs has stored fuel oil with total particulates not within limits for reasons not related to new fuel oil, the fuel oil must be restored within limits within 7 days. The fuel oil particulate properties are verified by SR 3.8.3.2. Trending of particulate levels normally allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample practices (bottom sampling), contaminated sampling equipment, or errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7 day Completion Time allows for further evaluation, resampling and re-analysis of the DG fuel oil.

(continued)

BASES

ACTIONS (continued)

C.1

With the new fuel oil properties defined in SR 3.8.3.2 not within required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combinations of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that the DG would still be capable of performing its intended function.

D.1

With a Required Action and associated Completion Time not met, or one or more DG's fuel oil not within limits for reasons other than addressed by Conditions A, B, or C (e.g., cloud point temperature reached), the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR verifies an onsite supply of ≥ 5000 gal of fuel oil is available for each required DG. This ensures that there is an adequate inventory of fuel oil in the storage tanks to support each DG's operation for 40 hours while providing maximum post-LOCA loads. The 40 hour period is sufficient time to place the plant in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The Frequency of 31 days is adequate to ensure that a sufficient supply of fuel oil is available, since indications are available to ensure that operators would be aware of any large uses of fuel oil during this period.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.2

This SR provides a means of determining whether new and stored fuel oil has been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. This ensures the availability of high quality fuel oil for the DGs. Fuel oil degradation during long term storage is indicated by an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which could eventually cause engine failure.

A fuel oil sample is analyzed to establish that properties specified in Table 1 of ASTM D975-78 (Ref. 4) for viscosity, water, and sediment are met for the stored fuel oil.

The Frequency of this SR takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals. The Frequency, as specified in the Diesel Fuel Oil Testing Program, is 92 days.

REFERENCES

1. UFSAR, Section 9.5.4.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.
4. ASTM Standards, D975-78, Table 1.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources—MODES 1, 2, 3, and 4

BASES

BACKGROUND

A source of electrical power is required for most safety related and nonessential active components. Two sources of electrical power are available, alternating current (AC) and direct current (DC). Separate distribution systems are developed for these two electrical power sources which are further divided and organized based on voltage considerations and whether they are Class 1E (i.e., supply safety related or engineered safeguards functions) or nonessential. This LCO is provided to specify the minimum sources of DC power which are required to supply the DC buses and their associated distribution system during MODES 1, 2, 3, and 4.

The station DC electrical power subsystem provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment and preferred AC instrument bus power (via inverters). Atomic Industrial Forum (AIF) GDC 39 (Ref. 1) requires emergency power sources be provided and designed with adequate independence, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems.

The 125 VDC electrical power system consists of two independent and redundant safety related Class 1E DC electrical power distribution train (Train A and Train B). Each subsystem consists of one 125 VDC battery, two battery chargers supplied from the 480 V system, distribution panels and buses, and all the associated control equipment and interconnecting cabling (see Figure B 3.8.4-1). The batteries and battery chargers are addressed by this LCO.

(continued)

BACKGROUND (continued)

Each battery provides a separate source of DC power independent of AC power. Each of the two batteries is capable of carrying its expected shutdown loads following a plant trip and a loss of all AC power for a period of 4 hours without battery terminal voltage falling below 105 V. Major loads and approximate operating times on each battery are discussed in the UFSAR (Ref. 2).

There are four battery chargers available to the batteries. Chargers 1A and 1B are rated at 150 amps and chargers 1A1 and 1B1 are rated at 200 amps. Battery chargers 1A and 1A1 are normally aligned to battery A, and battery chargers 1B and 1B1 are normally aligned to battery B. A charging capacity of at least 150 amps is normally required to supply the necessary DC loads on each train and to provide a full battery charge to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated Design Basis Accident (DBA). The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution Systems — MODES 1, 2, 3, and 4," and LCO 3.8.10, "Distribution Systems — MODES 5 and 6."

The DC electrical power distribution subsystem also provide DC electrical power to the inverters, which in turn power the AC instrument buses. The inverters are described in more detail in Bases for LCO 3.8.7, "AC Instrument Bus Sources- MODES 1, 2, 3, and 4," and LCO 3.8.8, "AC Instrument Bus Sources- MODES 5 and 6."

Train A Engineered Safety Feature (ESF) equipment is supplied from battery A, while Train B ESF equipment is supplied from battery B. Additionally, the 480 V ESF switchgear and diesel generator (DG) control panels are supplied from either battery by means of an automatic transfer circuit in the switchgear and control panels. The normal supply from Train A (Buses 14 and 18 and DG A) is from DC distribution panels A. These panels also provide the emergency DC supply for Train B. Similarly, the normal supply from Train B (Buses 16 and 17 and DG B) is from DC distribution panels B. These panels also provide the emergency dc supply for Train A.

(continued)

BASES

BACKGROUND (continued)

Each 125 VDC battery and associated battery chargers are separately housed in a ventilated room with its associated distribution center. Each subsystem is located in an area separated physically and electrically from the other subsystem to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. The two battery rooms are supplied with ventilation by a common AC powered air conditioning and heating unit which also provides sufficient air changes to prevent hydrogen buildup. A redundant DC powered fan is also available in the event that all AC power is lost. The failure of both the AC powered and DC powered units does not result in unacceptable room service conditions until after 5 hours of continuous battery operation during a DBA (Ref. 2).

The batteries for Train A and Train B DC electrical power distribution subsystem are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. Battery size is based on 125% of required capacity for aging considerations. The minimum voltage limit is 2.13 V per cell, which corresponds to a total minimum voltage output of 128 V per battery.

Each battery charger for the Train A and Train B DC electrical power distribution subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger also has sufficient capacity to restore the battery from the design minimum charge to its fully charged state within 24 hours while supplying normal steady state loads discussed in the UFSAR, Chapter 8 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The initial conditions of a DBA and transient analyses (Refs. 3, 4, and 5), assume that ESF systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining at least one train of DC source OPERABLE in the event of:

a. An assumed loss of all offsite AC power or all onsite standby AC power; and

b. A worst case single failure.

In the event of a DBA, the OPERABILITY requirements of the DC electrical power sources ensures that one train of DC electrical power is available with:

a. An assumed loss of all offsite power; and

b. A worst case single failure (including the loss of one DC electrical power source).

In general, the accident analyses assume that all offsite power is lost at the time of the initiating event except where the availability of offsite power provides worst case conditions (e.g., steam line break with continued operation of the reactor coolant pumps). The availability of redundant offsite power sources (i.e., circuits 751 and 767) helps to reduce the potential to lose all offsite power. Providing redundant sources of DC power ensures that at least one DC power source is available if all onsite standby AC power is unavailable coincident with a single failure of one offsite power source during non accident conditions. In the event the plant is in the 100/0 or 0/100 mode, a redundant source of offsite power can be obtained by backfeeding through the main transformer using a flexible connection that can be tied into the plant auxiliary transformer 11. The plant can survive on the available battery power, alternate power sources, and turbine driven Auxiliary Feedwater pump during the estimated 8 hours required to provide this power transfer (Ref. 6). Therefore, the requirements of GDC 17 (Ref. 7) can be met at all times.

The DC sources satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

The Train A and Train B DC electrical power sources, each consisting of one battery, a charging capacity of at least 150 amps, and the corresponding control equipment and interconnecting cabling within the train are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an AOO or a postulated DBA. Loss of any one train DC electrical power source does not prevent the minimum safety function from being performed.

An OPERABLE DC electrical power source requires the battery and at least one battery charger with a capacity ≥ 150 amps to be operating and connected to the associated DC bus. The AC powered and DC powered fan units are not required to be OPERABLE for this LCO, but some form of ventilation may be required for SR 3.8.6.4 and SR 3.8.6.5.

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe plant operation and to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The DC electrical power requirements for MODES 5 and 6 are addressed in LCO 3.8.5, "DC Sources — MODES 5 and 6."

(continued)

BASES (continued)

ACTIONS

A.1

With one DC electrical power source inoperable, OPERABILITY must be restored within 2 hours. In this Condition, redundancy is lost and only one train is capable to completely respond to an event. If one of the required DC electrical power sources is inoperable, the remaining DC electrical power source has the capacity to support a safe shutdown and to mitigate an accident condition. A subsequent worst case single failure would, however, result in the complete loss of the remaining 125 VDC electrical power distribution subsystem with attendant loss of ESF functions. The 2 hour Completion Time reflects a reasonable time to assess plant status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power source is not restored to OPERABLE status, to prepare to effect an orderly and safe plant shutdown.

B.1 and B.2

If the inoperable DC electrical power source cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1

If both DC electrical power sources are inoperable, a loss of multiple safety functions exists; therefore, LCO 3.0.3 must be immediately entered.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or a battery cell) in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. The 7 day Frequency is consistent with manufacturer recommendations and IEEE-450 (Ref. 8).

SR 3.8.4.2

This SR verifies that the capacity of each battery is adequate to supply and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test. A battery service test is a special test of battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements specified in Reference 2.

The Surveillance Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), which state that the battery service test should be performed during refueling operations or at some other outage, with intervals between tests not to exceed 24 months.

This SR is modified by two Notes. Note 1 states that SR 3.8.4.3 may be performed in lieu of SR 3.8.4.2. This substitution is acceptable because SR 3.8.4.3 represents a more severe test of battery capacity than does SR 3.8.4.2. Note 2 states that this surveillance shall not be performed in MODE 1, 2, 3, or 4 because performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.3

This Surveillance verifies that each battery capacity is ≥ 80% of the manufacturer's rating when subjected to a performance discharge test. A battery performance test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity as determined by specified acceptance criteria. The test is intended to determine overall battery degradation due to age and usage.

A battery should be replaced if its capacity is below 80% of the manufacturer rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Frequency for this SR is 60 months when the battery is < 85% of its expected life with no degradation and 12 months if the battery shows degradation or has reached 85% of its expected life with a capacity < 100% of the manufacturer's rating. When the battery has reached 85% of its expected life with capacity ≥ 100% of the manufacturer's rating, the Frequency becomes 24 months. Battery degradation is indicated when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ 10% below the manufacturer rating. These Frequencies are considered acceptable based on the testing being performed in a conservative manner relative to the battery life and degradation. This ensures that battery capacity is adequately monitored and that the battery remains capable of performing its intended function.

This SR is modified by a Note stating that this SR shall not be performed in MODE 1, 2, 3, or 4. The reason for the Note is that during operation in these MODES, performance of this SR could cause perturbations to the electrical distribution system and challenge safety systems.

(continued)

BASES (continued)

REFERENCES

1. Atomic Industrial Forum (AIF) GDC 39, Issued for comment July 10, 1967.
2. UFSAR, Section 8.3.2.
3. UFSAR, Section 9.4.9.3.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. UFSAR, Section 8.3.1.
7. 10 CFR 50, Appendix A, GDC 17.
8. IEEE-450-1980.
9. Regulatory Guide 1.32, February 1977.
10. Regulatory Guide 1.129, December 1974.

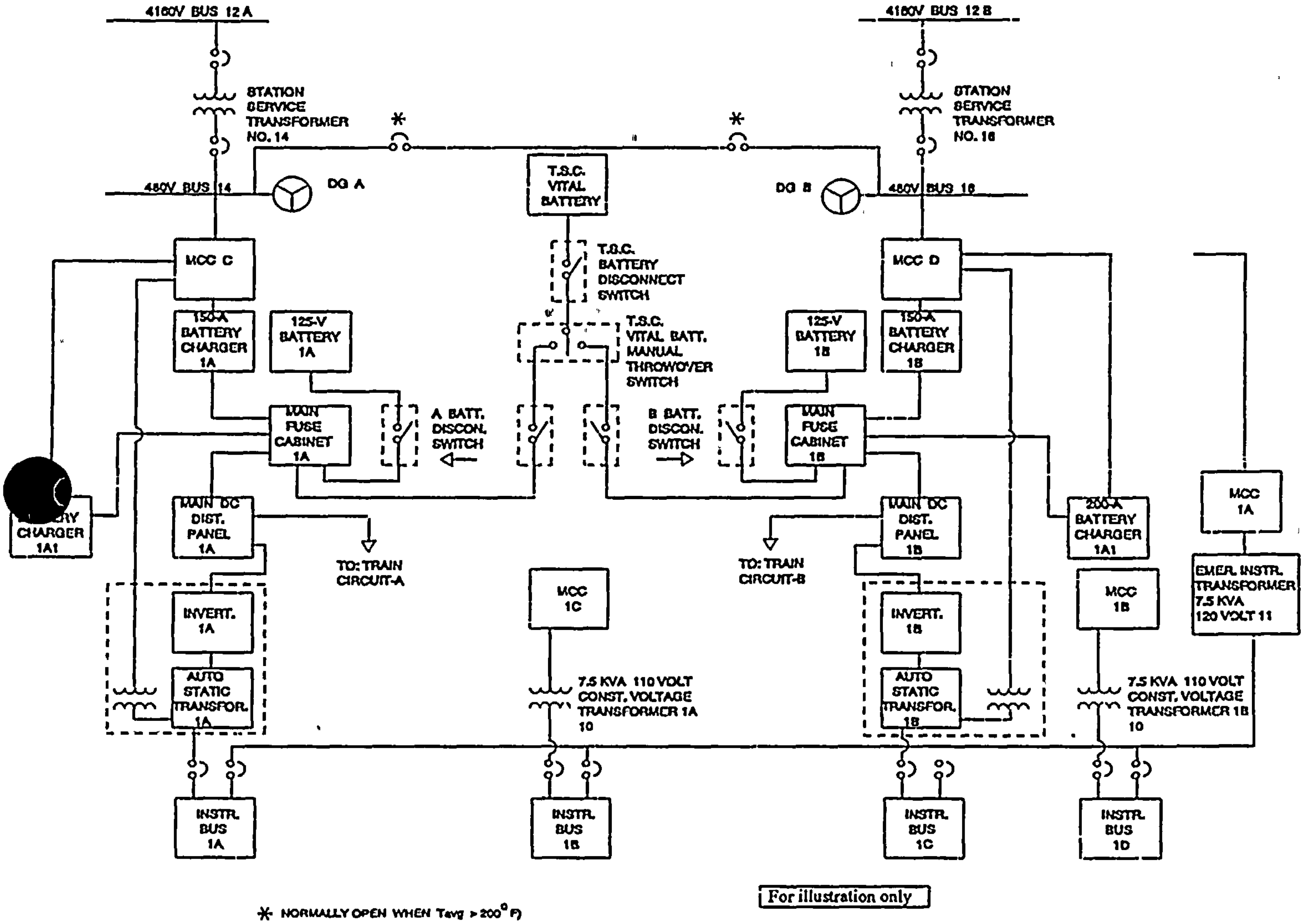


Figure B 3.8.4-1

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources — MODES 5 and 6

BASES

BACKGROUND

The Background section of the Bases for LCO 3.8.5, "DC Sources — MODES 1, 2, 3, and 4" is applicable to these Bases, with the following modifications.

In MODE 5 or 6, the number of required DC electrical sources may be reduced since less energy is retained within the reactor coolant system than during higher MODES. Also, a significant number of required testing and maintenance activities must be performed under these conditions such that equipment and systems, including the DC electrical sources, must be removed from service. The minimum required DC electrical sources is based on the requirements of LCO 3.8.10, "Distribution Systems — MODES 5 and 6.

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum DC electrical power sources during MODES 5 and 6 ensures that:

a. Required features needed to mitigate a fuel handling accident are available;

b. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

c. Instrumentation and control capability is available for monitoring and maintaining the plant in a cold shutdown condition or refueling condition.

In general, when the plant is shut down, the Technical Specifications requirements ensure that the plant has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. Therefore, the OPERABILITY of the DC electrical power sources ensures that one train of DC sources are OPERABLE in the event of:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. An assumed loss of all offsite AC power;

b. An assumed loss of all onsite standby AC power; or

c. A worst case single failure.

This reduction in required AC sources is allowed because many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary (reactor coolant temperature and pressure) and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and result in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCOs for the systems required in MODES 5 and 6.

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) for systems assumed to function during an event.

In the event of an accident while in MODE 5 or 6, this LCO ensures the capability to support systems necessary to mitigate the postulated events during shutdown, assuming either a loss of all offsite power or a loss of all onsite diesel generator (DG) power.

The DC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

The DC electrical power sources are required to be OPERABLE to support the distribution subsystems required OPERABLE by LCO 3.8.10, "Distribution Systems — MODES 5 and 6." If only one DC electrical power distribution train is required to be OPERABLE, the minimum source consists of a battery, a charging capacity of at least 150 amps, and the corresponding control equipment and interconnecting cabling within the required train. If both DC electrical power trains are required, one DC source must contain a battery, a charging capacity of at least 150 amps, and the corresponding control equipment and interconnecting cabling within the train system. The second DC source may consist of only a battery charger with a capacity of at least 150 amps, or a battery, and the corresponding control equipment and interconnecting cabling. The two must be sufficiently independent that a loss of all offsite power sources, a loss of onsite standby power, or a worst case single failure does not affect more than one required DC electrical power train. This ensures the availability of sufficient DC electrical power sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

The AC powered and DC powered fan ventilation units are not required to be OPERABLE for this LCO, but some form of ventilation may be required to meet SR 3.8.6.4 and SR 3.8.6.5.

(continued)

BASES (continued)

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6 provide assurance that systems required to mitigate the affects of a DBA and to maintain the plant in the cold shutdown or refueling condition are available.

The DC electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4, "DC Sources—MODES 1, 2, 3, and 4."

ACTIONS

A.1

Although two trains may be required by LCO 3.8.10, "Distribution Systems—MODES 5 and 6," the remaining DC electrical train may be capable of supporting sufficient systems to allow continuation of CORE ALTERATIONS, and operations with a potential for positive reactivity additions. By allowing the option to declare required features inoperable associated with the required inoperable DC power source(s), appropriate restrictions will be implemented in accordance with the LCO ACTIONS of the affected required features. Required features remaining powered from a DC electrical source, even if that source is considered inoperable because it is not powering other required features, are not declared inoperable by this Required Action.

(continued)

BASES

ACTIONS (continued)

A.2.1, A.2.2, A.2.3, and A.2.4

With one or more required DC electrical power sources inoperable, the option exists to declare all required features inoperable per Required Action A.1. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. Therefore, immediate suspension of CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions is an acceptable option to Required Action A.1. Performance of Required Actions A.2.1, A.2.2, and A.2.3 shall not preclude completion of movement of a component to a safe position or normal cooldown of the coolant volume for the purpose of system temperature control.

It is further required to immediately initiate action to restore the required DC electrical power source and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

This SR requires the performance of SRs from LCO 3.8.4 that are necessary for ensuring the OPERABILITY of the DC electrical power subsystem in MODES 5 and 6.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.8.5.1</u> (continued) This SR precludes requiring the OPERABLE DC electrical power source from being removed from service to perform a battery service test or a performance discharge test. With limited DC sources available, a single event could compromise multiple required safety features. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DC electrical power source is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.4 for a discussion of the specified SR.
REFERENCES	None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND

Each DC electrical power train contains a 125 VDC battery which is capable of carrying the expected shutdown loads following a plant trip and a loss of all AC power for a period of 4 hours without battery terminal voltage falling below 105 V. Major loads and approximate operating times on each battery are discussed in the UFSAR (Ref. 1). The batteries are normally in standby since the associated battery chargers provide for the required DC system loads.

The batteries for Train A and Train B DC electrical power are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and 100% design demand. Battery size is based on 125% of required capacity for aging considerations.

This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC power source batteries to ensure that the batteries are capable of performing their safety function as required by LCO 3.8.4, "DC Sources — MODES 1, 2, 3, and 4," and LCO 3.8.5, "DC Sources — MODES 5 and 6."

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses assume Engineered Safety Feature systems are OPERABLE (Refs. 2 and 3). The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation. The DC sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to Engineered Safety Feature systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, "Power Distribution Limits;" Section 3.4, "Reactor Coolant System (RCS);" and Section 3.6, "Containment Systems."

Battery cell parameters satisfy Criterion 3 of the NRC Policy Statement.

LCO

This LCO requires that battery cell parameters for Train A and B batteries be within limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery cell parameters are defined for electrolyte level, temperature, float voltage, and specific gravity. The limits for electrolyte level, float voltage, and specific gravity are conservatively established for both designated pilot cells and connected cells within plant procedures. Failure to meet these established limits may allow continued DC electrical system function provided that the limit specified in the associated Surveillance Requirement for each connected cell is not exceeded. The term "connected cell" excludes any battery cell that may be jumpered out.

(continued)

BASES (continued)

APPLICABILITY

The battery cell parameters for Train A and Train B batteries are required solely for the support of the associated DC electrical power subsystem. Therefore, the battery cell parameter limits are required to be met when the DC power source is required to be OPERABLE. Since the Train A and Train B batteries support LCO 3.8.4 and LCO 3.8.5, the battery cell parameters are required to be met in MODES 1, 2, 3, and 4, and when the associated DC electrical power subsystems are required to be OPERABLE in MODES 5 and 6.

ACTIONS

The ACTIONS are modified by a Note to provide clarification that separate condition entry is allowed for each battery. Separate Condition entry is acceptable since the battery cell parameters are provided on a battery basis.

A.1

With one or more batteries with one or more battery cell parameters outside the limits for any connected cell, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC electrical power train must be immediately declared inoperable and actions taken per LCO 3.8.4 or LCO 3.8.5.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that the electrolyte level of each connected battery cell is above the top of the plates and not overflowing. This is consistent with IEEE-450 (Ref. 4) and ensures that the plates suffer no physical damage and maintain adequate electron transfer capability. The Frequency of 31 days is consistent with IEEE-450.

SR 3.8.6.2

This SR verifies that the float voltage of each connected battery cell is > 2.07 V. This limit is based on IEEE-450 (Ref. 4) which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement. The frequency of 31 days is also consistent with IEEE-450.

SR 3.8.6.3

This SR verifies the specific gravity of the designated pilot cell in each battery is ≥ 1.188 for Battery A and ≥ 1.192 for Battery B. These values are based on manufacturer recommendations. According to IEEE-450 (Ref. 4), the specific gravity readings are based on a temperature of 77°F (25°C). The specific gravity readings are corrected for actual electrolyte temperature. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is further discussed in IEEE-450. The Frequency of 31 days is consistent with IEEE-450.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.4

This SR verifies the average electrolyte temperature of the designated pilot cell in each battery is ≥ 55°F. This temperature limit is an initial assumption of the battery capacity calculations. The Frequency of 31 days is consistent with IEEE-450 (Ref. 4).

SR 3.8.6.5

This SR verifies that the average temperature of every fifth cell of each battery is ≥ 55°F. This is consistent with the recommendations of IEEE-450 (Ref. 4). Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. The Frequency of 92 days is consistent with IEEE-450.

SR 3.8.6.6

This SR verifies the specific gravity of each connected cell is not more than 0.020 below average of all connected cells and that the average of all connected cells is ≥ 1.188 for Battery A and ≥ 1.192 for Battery B. These values are based on manufacturer recommendations and IEEE-450 (Ref. 4) which ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery. The temperature correction for specific gravity readings is the same as that discussed for SR 3.8.6.3. The Frequency of 92 days is consistent with IEEE-450.

REFERENCES

1. UFSAR, Section 3.8.2.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.
4. IEEE-450-1980.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 AC Instrument Bus Sources — MODES 1, 2, 3, and 4

BASES

BACKGROUND

The AC instrument bus electrical power distribution subsystem consists of four 120 VAC instrument buses. The power source for one 120 VAC instrument bus (Instrument Bus D) is normally supplied from offsite power via a non-Class 1E constant voltage transformer (CVT) such that only three buses are considered safety related (see Figure 3.8.4-1). These three 120 VAC instrument buses (A, B, and C) supply a source of power to instrumentation and controls which are used to monitor and actuate the Reactor Protection System (RPS) and Engineered Safety Features (ESF) and other components (Ref. 1). The loss of Instrument Bus D is addressed in LCO 3.3.2, "Engineered Safety Features Actuation System (ESFAS) Instrumentation," and LCO 3.3.3, "Post-Accident Monitoring Instrumentation."

Instrument Buses A and C can be supplied power either from inverters which are powered from separate and redundant DC power sources, a non-Class 1E CVT (maintenance CVT) powered from offsite power, or a Class 1E CVT (see Figure B 3.8.4-1). The inverters are the preferred source of power for Instrument Bus A and C because of the stability and reliability they achieve.

Instrument Bus B can be supplied power from either a Class 1E CVT or a non-Class 1E CVT (maintenance CVT) powered from offsite power. The Class 1E CVT, supplied by motor control center C (MCC C is supplied by 480 V safeguards Bus 14), is the preferred source of power for Instrument Bus B because of the potential to have a power interruption if offsite power were unavailable.

(continued)

BASES

BACKGROUND (continued)

The majority of instrumentation and controls supplied by the 120 VAC instrument buses are fail safe devices such that they go to their post accident position upon loss of power. However, a notable exception to this is the actuation logic for Containment Spray (CS) System which requires 120 VAC and 125 VDC power in order to function. This prevents a spurious CS actuation from occurring if control power were lost. The actuation logic for CS is powered from all three instrument buses and from both DC electrical power distribution trains.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses (Refs. 2 and 3), assume Engineered Safety Feature systems are OPERABLE. The AC instrument bus power sources are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESF instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, "Power Distribution Limits;" Section 3.4, "Reactor Coolant System (RCS);" and Section 3.6, "Containment Systems."

The OPERABILITY of the AC instrument bus power sources is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the plant. This includes maintaining required AC instrument buses OPERABLE in the event of:

a. An assumed loss of all offsite AC electrical power or all onsite standby AC power; and

b. A worst case single failure.

In the event of a DBA, the OPERABILITY requirements of the AC instrument bus power sources ensures that one train of AC instrument buses are available with:

a. An assumed loss of all offsite power; and

b. A worst case single failure (including the loss of one AC instrument bus power source).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In general, the accident analyses assume that all offsite power is lost at the time of the initiating event except where the availability of offsite power provides worst case conditions (e.g., steam line break with continued operation of the reactor coolant pumps). The availability of redundant offsite power sources (i.e., circuits 751 and 767) helps to reduce the potential to lose all offsite power. Providing redundant sources of AC instrument bus power also ensures that at least one train of AC instrument buses is available if all onsite standby AC power is unavailable coincident with a single failure of one offsite power source during non accident conditions. In the event the plant is in the 100/0 or 0/100 mode, a redundant source of offsite power can be obtained by backfeeding through the main transformer using a flexible connection that can be tied into the plant auxiliary transformer 11. The plant can survive on the available battery power, alternate power sources, and turbine driven Auxiliary Feedwater pump during the estimated 8 hours required to provide this power transfer (Ref. 4). Therefore, the requirements of GDC 17 (Ref. 5) can be met at all times.

The AC instrument bus sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

The AC instrument bus sources ensure the availability of 120 VAC electrical power for the instrumentation for systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required AC instrument bus sources OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESF instrumentation and controls is maintained. The two inverters ensure an uninterruptible supply of AC electrical power to AC Instrument Bus A and C even if the 480 V safeguards buses are de-energized. The Class 1E 480 V safeguard bus supply to Instrument Bus B provides a reliable source for the third instrument bus.

(continued)

BASES

LCO (continued)

For an inverter to be OPERABLE, the associated instrument bus must be powered by the inverter with output voltage within tolerances with power input to the inverter from a 125 VDC power source (see LCO 3.8.4, "DC Sources - MODES 1, 2, 3, and 4").

For a Class 1E CVT to be OPERABLE, the associated instrument bus must be powered by the CVT with the output voltage within tolerances with power to the CVT from a Class 1E 480 V safeguards bus. The 480 V safeguards bus must be powered from an acceptable AC source (see LCO 3.8.1, "AC Sources - MODES 1, 2, 3, and 4").

APPLICABILITY

The AC instrument bus power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

AC instrument bus power requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, " AC Instrument Bus Sources - MODES 5 and 6."

ACTIONS

A.1, A.2, and A.3

With an inverter inoperable, its associated AC instrument bus becomes inoperable until it is re-energized from either its Class 1E or non-Class 1E CVT.

Required Action A.1 allows the instrument bus to be powered from either its associated Class 1E CVT or from a non-Class 1E CVT. For Instrument Buses A and C, the non-Class 1E power is supplied by a non-safety related motor control center (MCC A) which is supplied by 480 V Bus 13. The Completion Time of 2 hours is consistent with LCO 3.8.9, "Distribution Systems - MODES 1, 2, 3, and 4".

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

Required Action A.2 is intended to limit the amount of time that the instrument bus can be connected to a non-Class 1E power supply. The 24 hour Completion Time is based upon engineering judgement, taking into consideration the time required to repair the Class 1E CVT or the inverter and the additional risk to which the plant is exposed because of the connection to a non-Class 1E power supply.

Required Action A.3 allows 72 hours to fix the inoperable inverter and restore it to OPERABLE status. The 72 hour Completion Time is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the plant is exposed because of the inverter inoperability. This must be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the AC instrument bus is powered from its CVT, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible, battery backed inverter source to the AC instrument buses is the preferred source for powering instrumentation trip setpoint devices.

B.1 and B.2

With the Class 1E CVT for Instrument Bus B inoperable, the instrument bus becomes inoperable until it is re-energized from its non-Class 1E CVT. Required Action B.1 requires Instrument Bus B to be powered from its non-Class 1E CVT within 2 hours. The non-Class 1E power is supplied by a nonsafety related 480 V motor control center (MCC A) which is supplied by 480 V Bus 13.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Required Action B.2 is intended to limit the amount of time that Instrument Bus B can be connected to a non-Class 1E power supply. The 7 day limit is based on engineering judgement, taking into consideration the time required to repair the Class 1E CVT and the additional risk to which the plant is exposed because of the Class 1E CVT inoperability. This must be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When Instrument Bus B is powered from its non-Class 1E CVT, it is relying upon interruptible offsite AC electrical power sources. The Class 1E, diesel generator backed, CVT to Instrument Bus B is the preferred power source for powering instrumentation trip setpoint devices.

C.1 and C.2.

If the inoperable devices or components cannot be restored to OPERABLE status or other Required Actions are not completed within the required Completion Time of Condition A or B, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

If two or more required AC instrument bus power sources are inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately. This Condition must be entered when both inverters, or one or more inverters and the Class 1E CVT to Instrument Bus B are discovered to be inoperable.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This SR verifies correct static switch alignment to Instrument Bus A and C. This verifies that the inverters are functioning properly and AC Instrument Bus A and C are energized from their respective inverter. The verification ensures that the required power is available for the instrumentation of the RPS and ESF connected to the AC instrument buses. The Frequency of 7 days takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

SR 3.8.7.2

This SR verifies the correct Class 1E CVT alignment to Instrument Bus B. This verifies that the Class 1E CVT is functioning properly and supplying power to AC Instrument Bus B. The verification ensures that the required power is available for the instrumentation of the RPS and ESF connected to the AC instrument bus. The Frequency of 7 days takes into account the redundant instrument buses and other indications available in the control room that alert the operator to the Class 1E CVT malfunctions.

REFERENCES

1. UFSAR, Chapter 8.3.2.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.
4. UFSAR, Section 8.3.1.
5. 10 CFR 50, Appendix A, GDC 17.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 AC Instrument Bus Sources – MODES 5 and 6

BASES

BACKGROUND

The Background section of the Bases for LCO 3.8.7, "AC Instrument Bus Sources – MODES 1, 2, 3, and 4" is applicable to these Bases, with the following modifications.

In MODE 5 or 6, the number of required AC instrument buses may be reduced since less energy is retained within the reactor coolant system than during higher MODES. Also, a significant number of required testing and maintenance activities must be performed under these conditions such that equipment and systems, including the AC instrument bus sources, must be removed from service. The minimum required AC instrument bus electrical subsystem is bases on the requirements of LCO 3.8.10, "Distribution Systems – MODES 5 and 6."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC instrument bus power sources to each required AC instrument bus during MODES 5 and 6 ensures that:

a. Systems needed to mitigate a fuel handling accident are available;

b. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

c. Instrumentation and control capability is available for monitoring and maintaining the plant in a cold shutdown condition or refueling condition.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In general, when the plant is shut down, the Technical Specifications requirements ensure that the plant has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. Therefore, the OPERABILITY of the AC instrument bus power sources ensures that one train of the AC instrument buses are OPERABLE in the event of:

a. An assumed loss of all offsite AC power;

b. An assumed loss of all onsite standby AC power; or

c. A worst case single failure.

This reduction in required AC sources is allowed because many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary (reactor coolant temperature and pressure) and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and result in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCOs for the systems required in MODES 5 and 6.

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) for systems assumed to function during an event.

In the event of an accident while in MODE 5 or 6, this LCO ensures the capability to support systems necessary to mitigate the postulated events during shutdown, assuming either a loss of all offsite power or a loss of all onsite diesel generator (DG) power.

The AC instrument bus power sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

Maintaining the required AC instrument bus sources OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESF instrumentation and controls is maintained. The two inverters ensure an uninterruptible supply of AC electrical power to AC Instrument Bus A and C even if the 480 V safeguards buses are de-energized. The Class 1E 480 V safeguard bus supply to Instrument Bus B provides a reliable source for the third instrument bus.

For an inverter to be OPERABLE, the associated instrument bus must be powered by the inverter with output voltage within tolerances with power input to the inverter from a 125 VDC power source (see LCO 3.8.4, "DC Sources—MODES 1, 2, 3, and 4).

(continued)

BASES

LCO (continued)

For a Class 1E CVT to be OPERABLE, the associated instrument bus must be powered by the CVT with the output voltage within tolerances with power to the CVT from a Class 1E 480 V safeguards bus. The 480 V safeguards bus must be powered from an acceptable AC source (see LCO 3.8.1, "AC Sources — MODES 1, 2, 3, and 4). Power sources ensure the availability of sufficient power to the required AC instrument buses to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6 provide assurance that systems required to mitigate the effects of a DBA and to maintain the plant in the cold shutdown or refueling condition are available.

AC Instrument Bus power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

ACTIONS

A.1

Although two trains may be required by LCO 3.8.10, "Distribution Systems — MODES 5 and 6," the remaining OPERABLE AC instrument bus train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and operations with a potential for positive reactivity additions. By allowing the option to declare required features inoperable with the associated AC instrument bus power source inoperable, appropriate restrictions will be implemented in accordance with the LCO ACTIONS of the affected required features. This condition must be entered when the inverters for Instrument Bus A or C are inoperable, or the Class 1E CVT for Instrument Bus B is inoperable.

(continued)

BASES

ACTIONS (continued)

A.2.1, A.2.2, A.2.3, and A.2.4

With one or more required AC instrument bus power sources inoperable, the option exists to declare all required features inoperable per Required Action A.1. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. Therefore, immediate suspension of CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions is an acceptable option to Required Action A.1. Performance of Required Actions A.2.1, A.2.2, and A.2.3 shall not preclude completion of movement of a component to a safe position or normal cooldown of the coolant volume for the purpose of system temperature control.

It is further required to immediately initiate action to restore the required AC instrument bus power source and to continue this action until restoration is accomplished in order to provide the necessary power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC instrument bus power source should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power or powered from an alternate power source.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This SR verifies correct static switch alignment to the required AC instrument buses. This SR verifies that the inverter is functioning properly and the AC instrument bus is energized from the inverter. The verification ensures that the required power is available for the instrumentation connected to the AC instrument bus. The Frequency of 7 days takes into account the redundant capability of the inverter and other indications available in the control room that alert the operator to inverter malfunctions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.8.2

This SR verifies the correct Class 1E CVT alignment when Instrument Bus B is required. This verifies that the Class 1E CVT is functioning properly and supplying power to AC Instrument Bus B. 3 The verification ensures that the required power is available for the instrumentation of the RPS and ESF connected to the AC instrument bus. The Frequency of 7 days takes into account the redundant instrument buses and other indications available in the control room that alert the operator to the Class 1E CVT malfunctions.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems — MODES 1, 2, 3, and 4

BASES

BACKGROUND

A source of electrical power is required for most safety related and nonessential action components. Two sources of electrical power are available, alternating current (AC) and direct current (DC). Separate distribution systems are developed for each of these electrical power sources which are further divided and organized based on voltage considerations and safety classification. This LCO is provided to specify the AC, DC, and AC instrument bus power electrical power distribution subsystems which are required to supply safety related and Engineered Safety Feature (ESF) Systems in MODES 1, 2, 3, and 4.

The onsite Class 1E AC, DC, and AC instrument bus electrical power distribution subsystems are each divided into two redundant and independent distribution trains. Each of these electrical power distribution subsystems, and their trains, are discussed in detail below.

(continued)

BASES

BACKGROUND (continued)

AC Electrical Power Distribution Subsystem

The Class 1E AC electrical power distribution subsystem is organized into two redundant and independent trains (Train A and Train B). Each train consists of two 480 V safeguards buses, distribution panels, motor control centers and load centers (see Figure B 3.8.1-1). The 480 V safeguards buses for each train are capable of being supplied from two sources of offsite power as well as a dedicated onsite emergency diesel generator (DG) source. These power sources are discussed in more detail in the Bases for LCO 3.8.1, "AC Sources - MODES 1, 2, 3, and 4." The 480 V safeguards buses in turn supply motor control centers, distribution panels and load centers which supply motive power to required motor operated valves, pumps, dampers, or any other component which requires AC power to perform its safety related function. The AC electrical power distribution subsystem also supplies one of the three required AC instrument buses through a constant voltage transformer and provides a backup source for the other two instrument buses. The list of all required AC 480 V safeguards buses is provided in Table B 3.8.9-1.

DC Electrical Power Distribution Subsystem

The Class 1E DC electrical power distribution subsystem is organized into two redundant and independent trains (Train A and Train B). Each train consists of a Class 1E battery and two battery chargers (with a charging capacity of at least 150 amps) which supply a main 125 VDC distribution panel (see Figure B 3.8.4-1). These power sources are discussed in more detail in the Bases for LCO 3.8.4, "DC Sources - MODES 1, 2, 3, and 4." Each main distribution panel supplies secondary distribution panels which provide control power to AC powered components and control power for other devices such as solenoid operated valves and air operated valves. The DC electrical power distribution subsystem also supplies two of the four AC instrument buses through inverters. The list of all required DC distribution panels is provided in Table B 3.8.9-1.

(continued)

BASES

BACKGROUND (continued)

AC Instrument Bus Electrical Power Distribution Subsystem

The AC instrument bus electrical power distribution subsystem consists of four 120 VAC instrument buses. The power source for one 120 VAC instrument bus (Instrument Bus D) is supplied from offsite power via a non Class 1E constant voltage transformer (CVT) such that only three buses are considered safety related (see Figure B 3.8.4-1). These three buses are organized into two redundant and independent trains (Train A and Train B). These trains supply a source of power to instrumentation and controls which are used to monitor and actuate ESF and other components. Train A consists of two buses with one bus (Instrument Bus A) normally powered from an inverter and the other (Instrument Bus B) normally powered from a Class 1E CVT. Train B consists of one bus (Instrument Bus C) normally powered from an inverter. The long-term alternate power supplies for Instrument Bus A and C are two Class 1E CVTs, each powered from the same train as the associated battery chargers, and their use is governed by LCO 3.8.7, "AC Instrument Bus Sources — MODES 1, 2, 3, and 4." The list of required 120 VAC instrument buses is provided in Table B 3.8.9-1. The loss of Instrument Bus D is addressed in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," and LCO 3.3.3, "Post-Accident Monitoring (PAM) Instrumentation."

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses (Refs. 1 and 2) assume ESF systems are OPERABLE. The AC, DC, and AC instrument bus electrical power distribution subsystems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, "Power Distribution Limits;" Section 3.4, "Reactor Coolant System (RCS);" and Section 3.6, "Containment Systems."

The OPERABILITY of the AC, DC, and AC instrument bus electrical power distribution subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining power distribution subsystems OPERABLE in the event of:

a. An assumed loss of all AC offsite power or all onsite standby AC power; and

b. A worst case single failure.

In the event of a DBA, the OPERABILITY requirements of the AC, DC, and AC instrument bus electrical power distribution subsystems ensures that one train of each distribution subsystem is available with:

a. An assumed loss of all offsite power; and

b. A worst case single failure (including the loss of one train of offsite standby AC power).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In general, the accident analyses assume that all offsite power is lost at the time of the initiating event except where the availability of offsite power provides worst case conditions (e.g., steam line break with continued operation of the reactor coolant pumps). The availability of redundant offsite power sources (i.e., circuits 751 and 767) helps to reduce the potential to lose all offsite power. Providing redundant sources of offsite power also ensures that at least one AC, DC, and AC instrument bus train is available if all onsite standby AC power is unavailable coincident with a single failure of one offsite power source during non accident conditions. In the event the plant is in the 100/0 or 0/100 mode, a redundant source of offsite power can be obtained by backfeeding through the main transformer using a flexible connection that can be tied into the plant auxiliary transformer 11. The plant can survive on the available battery power, alternate power sources, and turbine driven Auxiliary Feedwater train during the estimated 8 hours required to provide this power transfer (Ref. 3). Therefore, the requirements of GDC 17 (Ref. 4) can be met at all times.

The AC, DC, and AC instrument bus electrical power distribution subsystems satisfy Criterion 3 of the NRC Policy Statement.

LCO

Train A and Train B of the AC, DC, and AC instrument bus electrical power distribution subsystems are required to be OPERABLE. The power distribution subsystems and their trains listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC instrument bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

(continued)

BASES

LCO (continued)

OPERABLE AC, DC, and AC instrument bus electrical power distribution subsystems require the associated buses, load centers, motor control centers, and distribution panels to be energized to their proper voltages. Maintaining the Train A and Train B AC, DC, and AC instrument bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not compromised. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

Tie breakers between redundant safety related AC, DC, and AC instrument bus power distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s).

If any of the following listed tie breakers are closed, the affected redundant electrical power distribution subsystem is considered inoperable. This does not, however, preclude AC buses from being powered from the same offsite circuit.

a. AC power 480 V safeguards bus tie breakers (Ref. 5)

   Bus-Tie 14-16
   Bus-Tie 16-14
   Bus-Tie 17-18
   Bus-Tie 16-15
   Bus-Tie 14-13

b. DC control power automatic throwover switches (in normal position) (Ref. 6)

   DG Control Panel A
   DG Control Panel B
   Bus 14 Control Power and Undervoltage Cabinet
   Bus 16 Control Power and Undervoltage Cabinet
   Bus 17 Control Power and Undervoltage Cabinet
   Bus 18 Control Power and Undervoltage Cabinet

(continued)

BASES

LCO (continued)

c. Technical Support Center battery connections to DC power Battery A and B (Ref. 6)

TSC/Battery A Fused Disconnect Switch
TSC/Battery B Fused Disconnect Switch

The trains as specified in Table B 3.8.9-1 only identify the major AC, DC, and AC instrument bus electrical power distribution subsystem components. A train is defined to begin from the boundary of the power source for the respective subsystem (as defined in the power source LCOs), and continues up to the isolation device for the supplied safety related or ESF component (e.g., safety injection pump). The isolation device for the supplied safety related or ESF component is only considered part of the train when the device is not capable of opening to isolate the failed component from the train (e.g., breaker unable to open an overcurrent). Otherwise, the failure of the isolation device to close to provide power to the component is addressed by the respective component's LCO. The isolation device for nonsafety related components are considered part of the train since these devices must be available to protect the safety related functions. Therefore, the train boundary essentially ends at the motor control center or bus which supplies multiple components.

The inoperability of any component within the above defined train boundaries renders the train inoperable.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

(continued)

BASES

APPLICABILITY (continued)

Electrical power distribution subsystem requirements for MODES 5 and 6 are addressed in LCO 3.8.10, "Distribution Systems — MODES 5 and 6."

ACTIONS

A.1

With one AC electrical power distribution train inoperable, the remaining AC electrical power distribution train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition. The overall reliability is reduced, however, because a single failure in the remaining AC power distribution train could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels which comprise a train must be restored to OPERABLE status within 8 hours.

The worst case Condition A scenario is one train without AC power (i.e., no offsite power to the train and the associated DG inoperable). In this Condition, the plant is more vulnerable to a complete loss of AC power.

The Completion Time for restoring the inoperable train before requiring a plant shutdown is limited to 8 hours because of:

a. The potential for decreased safety if the plant operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train; and

b. The potential for an event in conjunction with a single failure of a redundant component in the OPERABLE train with AC power which results in the loss of multiple safety functions.

(continued)

BASES

ACTIONS (continued)

B.1

With one AC instrument bus electrical power distribution train inoperable, the remaining OPERABLE AC instrument bus train is capable of supporting the minimum safety functions necessary to shut down the plant and maintain it in the safe shutdown condition. Overall reliability is reduced, however, because a single failure in the remaining AC instrument bus train could result in the minimum ESF functions not being supported. Therefore, the AC instrument bus train must be restored to OPERABLE status within 2 hours.

Condition B represents one AC instrument bus train without power which includes the potential loss of both the DC source and the associated AC sources to the instrument bus. In this situation, the plant is significantly more vulnerable to a complete loss of all noninterruptible power. Therefore, the Completion Time is limited to 2 hours due to the potential vulnerabilities. Taking exception to LCO 3.0.2 for components without adequate 120 VAC power, that would have Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in plant conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate 120 VAC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component in the OPERABLE AC instrument bus train.

(continued)

BASES

ACTIONS

B.1 (continued)

The 2 hour Completion Time takes into account the importance to safety of restoring the AC instrument bus train to OPERABLE status, the redundant capability afforded by the other OPERABLE instrument bus train, and the low probability of a DBA occurring during this period.

C.1

With one DC electrical power distribution train inoperable, the remaining DC electrical power distribution train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution train could result in the minimum required ESF functions not being supported. Therefore, the required DC distribution panels must be restored to OPERABLE status within 2 hours.

Condition C represents one train without adequate DC power (e.g., the battery and required battery charger are inoperable). In this situation, the plant is significantly more vulnerable to a complete loss of all DC power. Therefore, the Completion Time is limited to 2 hours due to this potential vulnerability. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in plant conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

(continued)

BASES

ACTIONS

C.1 (continued)

c. The potential for an event in conjunction with a single failure of a redundant component in the OPERABLE train with DC power.

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

With two trains with inoperable electrical power distribution subsystems, the potential for a loss of safety function is greater. If a loss of safety function exists, no additional time is justified for continued operation and LCO 3.0.3 must be entered. This Condition may be entered with the loss of two trains of the same electrical power distribution subsystem, or with loss of Train A of one electrical power distribution subsystem coincident with the loss of Train B of a second electrical power distribution subsystem such that a loss of safety function exists.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This SR verifies that the electrical power trains are functioning properly, with all required power source circuit breakers closed, tie-breakers open, and the buses energized from their allowable power sources. Required voltage for the AC electrical power distribution subsystem is ≥ 420 VAC; for the DC electrical power distribution subsystem, ≥ 108.6 VDC; and for AC instrument bus electrical power distribution subsystem, between 113 VAC and 123 VAC. Required voltage for the twinco panels supplied by the 120 VAC instrument buses is between 115.6 VAC and 120.4 VAC. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The Frequency of 7 days takes into account the redundant capability of the AC, DC, and AC instrument bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 15.
3. UFSAR, Section 8.3.1.
4. 10 CFR 50, Appendix A, GDC 17.
5. UFSAR, Figure 8.3-1.
6. UFSAR, Figure 8.3-6.

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

DISTRIBUTION SUBSYSTEM	VOLTAGE	TRAIN A	TRAIN B
AC Power	480 V	Bus 14 Bus 18	Bus 16 Bus 17
DC Power	125 V	Main DC Fuse Cabinet A (DCPDPCB02A) Main DC Distribution Panel A (DCPDPCB03A) Aux Bldg DC Distribution Panel A (DCPDPAB01A) Aux Bldg DC Distribution Panel A1 (DCPDPAB02A) DG A DC Distribution Panel A (DCPDPDG01A) Screenhouse DC Distribution Panel A (DCPDPSH01A) MCB DC Distribution Panel A (DCPDPDCB04A)	Main DC Fuse Cabinet B (DCPDPCB02B) Main DC Distribution Panel B (DCPDPCB03B) Aux Bldg DC Distribution Panel B (DCPDPAB01B) Aux Bldg DC Distribution Panel B1 (DCPDPAB02B) DG B DC Distribution Panel B (DCPDPDG01B) Screenhouse DC Distribution Panel B (DCPDPSH01B) MCB DC Distribution Panel B (DCPDPCB04B) Turbine Bldg DC Distribution Panel (DCPDPTB01B)
AC Instrument Bus	120 V	Bus A Bus B	Bus C

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems — MODES 5 and 6

BASES

BACKGROUND

The Background section of the Bases for LCO 3.8.9, "Distribution Systems — MODES 1, 2, 3, and 4" is applicable to these Bases, with the following modifications.

In MODES 5 or 6, the number of required AC, DC, and AC instrument bus electrical power distribution subsystems, or the number of required trains within these electrical power distribution subsystems may be reduced since less energy is retained within the reactor coolant system than during higher MODES. Also, a significant number of required testing and maintenance activities must be performed under these conditions such that equipment and systems, including the electrical power distribution subsystems, must be removed from service.

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC, DC, and AC instrument bus electrical power distribution subsystems during MODES 5 and 6 ensures that:

a. Systems needed to mitigate a fuel handling accident are available;

b. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

c. Instrumentation and control capability is available for monitoring and maintaining the plant in a cold shutdown condition and refueling condition.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

In general, when the plant is shut down, the Technical Specifications requirements ensure that the plant has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. Therefore, the OPERABILITY of the AC, DC, and AC instrument bus electrical power distribution subsystems ensures that one train of the onsite power or offsite AC sources are OPERABLE in the event of:

a. An assumed loss of all offsite AC power;

b. An assumed loss of all onsite standby AC power; or

c. A worst case single failure.

This reduction in required AC sources is allowed because many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary (reactor coolant temperature and pressure) and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and result in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCOs for the systems required in MODES 5 and 6.

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) for systems assumed to function during an event.

In the event of an accident while in MODE 5 or 6 this LCO ensures the capability to support systems necessary to mitigate the postulated events during shutdown, assuming either a loss of all offsite power or a loss of all onsite diesel generator (DG) power.

The AC, DC, and AC instrument bus electrical power distribution subsystems satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

Various combinations of AC, DC, and AC instrument bus electrical power distribution subsystems, trains within these subsystems, and equipment and components within these trains are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of required systems, equipment, and components — all specifically addressed in each LCO and implicitly required via the definition of OPERABILITY.

The LCOs which apply when the Reactor Coolant System is ≤ 200°F and which may require a source of electrical power are:

LCO 3.1.1	SHUTDOWN MARGIN (SDM)
LCO 3.3.1	Reactor Trip System (RTS) Instrumentation
LCO 3.3.4	Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation
LCO 3.3.6	Control Room Emergency Air Treatment System (CREATS) Actuation
LCO 3.4.7	RCS Loops - MODE 5, Loops Filled
LCO 3.4.8	RCS Loops - MODE 5, Loops Not Filled
LCO 3.4.12	Low Temperature Overpressure Protection (LTOP) System
LCO 3.7.9	Control Room Emergency Air Treatment System (CREATS)
LCO 3.9.2	Nuclear Instrumentation
LCO 3.9.4	Residual Heat Removal (RHR) and Coolant Circulation - Water Level ≥ 23 Ft
LCO 3.9.5	Residual Heat Removal (RHR) and Coolant Circulation - Water Level < 23 Ft

Maintaining the necessary trains of the AC, DC, and AC instrument bus electrical power distribution subsystems energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

(continued)

BASES (continued)

APPLICABILITY

The AC, DC, and AC instrument bus electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6 provide assurance that systems required to mitigate the effects of a postulated event and maintain the plant in the cold shutdown or refueling condition are available.

The AC, DC, and AC instrument bus electrical power distribution subsystems requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9, "Distribution Systems — MODES 1, 2, 3, and 4."

ACTIONS

A.1

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and operations involving positive reactivity additions. By allowing the option to declare required features associated with an inoperable distribution subsystem or train inoperable, appropriate restrictions are implemented in accordance with the LCO ACTIONS of the affected required features.

A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

With one or more required electrical power distribution subsystems or trains inoperable, the option exists to declare all required features inoperable per Required Action A.1. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. Therefore, immediate suspension of CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions is an acceptable option to Required Action A.1. Performance of Required Actions A.2.1, A.2.2, and A.2.3 shall not preclude completion of movement of a component to a safe position of normal cooldown of the coolant volume for the purpose of system temperature control within established procedures.

(continued)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

It is further required to immediately initiate action to restore the required AC, DC, and AC instrument bus electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the plant safety systems.

In addition to performance of the above conservative Required Actions, a required residual heat removal (RHR) loop may be inoperable. In this case, Required Actions A.2.1, A.2.2, A.2.3, and A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR ACTIONS would not be entered. Therefore, Required Action A.2.5 requires declaring RHR inoperable, which results in taking the appropriate RHR actions.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the electrical power distribution trains are functioning properly, with all the required power source circuit breakers closed, required tie-breakers open, and the required buses energized from their allowable power sources. Required voltage for the AC power distribution electrical subsystem is ≥ 420 VAC, for the DC power distribution electrical subsystem ≥ 108.6 VDC, and for AC instrument bus power distribution electrical subsystem is between 113 VAC and 123 VAC. Required voltage for the twinco panels supplied by the 120 VAC instrument buses is between 115.6 VAC and 120.4 VAC. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The Frequency of 7 days takes into account the capability of the AC, DC, and AC instrument bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

None.

3.9 REFUELING OPERATIONS

3.9.1 Boron Concentration

LCO 3.9.1 Boron concentrations of the Reactor Coolant System, the refueling canal, and the refueling cavity shall be maintained within the limit specified in the COLR.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Boron concentration not within limit.	A.1	Suspend CORE ALTERATIONS.	Immediately
	AND		
	A.2	Suspend positive reactivity additions.	Immediately
	AND		
	A.3	Initiate action to restore boron concentration to within limit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Verify boron concentration is within the limit specified in the COLR.	72 hours

3.9 REFUELING OPERATIONS

3.9.2 Nuclear Instrumentation

LCO 3.9.2 Two source range neutron flux monitors shall be OPERABLE.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One source range neutron flux monitor inoperable.	A.1	Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>		
	A.2	Suspend positive reactivity additions.	Immediately
B. Two source range neutron flux monitors inoperable.	B.1	Initiate action to restore one source range neutron flux monitor to OPERABLE status.	Immediately
	<u>AND</u>		
	B.2	Perform SR 3.9.1.1.	4 hours <u>AND</u> Once per 12 hours thereafter

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. No audible count rate.	C.1 Suspend CORE ALTERATIONS. AND C.2 Suspend positive reactivity additions. AND C.3 Perform SR 3.9.1.1	Immediately Immediately 4 hours AND Once per 12 hours thereafter

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.9.2.1 Perform CHANNEL CHECK.	12 hours
SR 3.9.2.2 -------------------NOTE------------------- Neutron detectors are excluded from CHANNEL CALIBRATION. --- Perform CHANNEL CALIBRATION.	24 months

3.9 REFUELING OPERATIONS

3.9.3 Containment Penetrations

LCO 3.9.3 The containment penetrations shall be in the following status:

a. The equipment hatch shall be either:

1. bolted in place with at least one access door closed, or

2. isolated by a closure plate that restricts air flow from containment;

b. One door in the personnel air lock shall be closed; and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere shall be either:

1. closed by a manual or automatic isolation valve, blind flange, or equivalent, or

2. capable of being closed by an OPERABLE Containment Ventilation Isolation System.

APPLICABILITY: During CORE ALTERATIONS,
During movement of irradiated fuel assemblies within containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment penetrations not in required status.	A.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2 Suspend movement of irradiated fuel assemblies within containment.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Verify each required containment penetration is in the required status.	7 days
SR 3.9.3.2	Verify each required containment purge and exhaust valve actuates to the isolation position on an actual or simulated actuation signal.	24 months

3.9 REFUELING OPERATIONS

3.9.4 Residual Heat Removal (RHR) and Coolant Circulation — Water Level ≥ 23 Ft

LCO 3.9.4 One RHR loop shall be OPERABLE and in operation.

------------------------------NOTE------------------------------
The required RHR loop may be removed from operation for ≤ 1 hour per 8 hour period, provided no operations are permitted that would cause reduction of the Reactor Coolant System (RCS) boron concentration.

APPLICABILITY: MODE 6 with the water level ≥ 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. RHR loop requirements not met.	A.1	Suspend operations involving a reduction in RCS boron concentration.	Immediately
	<u>AND</u>		
	A.2	Suspend loading irradiated fuel assemblies in the core.	Immediately
	<u>AND</u>		
	A.3	Initiate action to satisfy RHR loop requirements.	Immediately
	<u>AND</u>		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.4 Close all containment penetrations providing direct access from containment atmosphere to outside atmosphere.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.9.4.1 Verify one RHR loop is in operation and circulating reactor coolant.	12 hours

3.9 REFUELING OPERATIONS

3.9.5 Residual Heat Removal (RHR) and Coolant Circulation—Water Level < 23 Ft

LCO 3.9.5 Two RHR loops shall be OPERABLE, and one RHR loop shall be in operation.

APPLICABILITY: MODE 6 with the water level < 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Less than the required number of RHR loops OPERABLE.	A.1 Initiate action to restore RHR loop(s) to OPERABLE status.	Immediately
	<u>OR</u>	
	A.2 Initiate action to establish ≥ 23 ft of water above the top of reactor vessel flange.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. No RHR loop in operation.	B.1	Suspend operations involving a reduction in Reactor Coolant System boron concentration.	Immediately
	AND		
	B.2	Initiate action to restore one RHR loop to operation.	Immediately
	AND		
	B.3	Close all containment penetrations providing direct access from containment to outside atmosphere.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	Verify one RHR loop is in operation and circulating reactor coolant.	12 hours
SR 3.9.5.2	Verify correct breaker alignment and indicated power available to the required RHR pump that is not in operation.	7 days

3.9 REFUELING OPERATIONS

3.9.6 Refueling Cavity Water Level

LCO 3.9.6 Refueling cavity water level shall be maintained ≥ 23 ft above the top of reactor vessel flange.

APPLICABILITY: During movement of irradiated fuel assemblies within containment,
During CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refueling cavity water level not within limit.	A.1 Suspend CORE ALTERATIONS. AND A.2 Suspend movement of irradiated fuel assemblies within containment.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.9.6.1 Verify refueling cavity water level is ≥ 23 ft above the top of reactor vessel flange.	24 hours

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentration ensures the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the filled portions of the Reactor Coolant System (RCS), the refueling canal, and the refueling cavity that are hydraulically coupled to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant. The refueling boron concentration limit is specified in the Core Operation Limits Report (COLR). Plant refueling procedures ensure the specified boron concentration in order to maintain an overall core reactivity of $k_{eff} \leq 0.95$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant refueling procedures.

Atomic Industrial Forum (AIF) GDC 27 requires that two independent reactivity control systems preferably of different design principles be provided (Ref. 1). In addition to the reactivity control achieved by the control rods, reactivity control is provided by the chemical and volume control system (CVCS) which regulates the concentration of boric acid solution (neutron absorber) in the RCS. The CVCS is designed to prevent, under anticipated system malfunction, uncontrolled or inadvertent reactivity changes which may stress or damage the fuel beyond allowable limits.

The reactor is brought to shutdown conditions (i.e., MODE 5) before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized the vessel head is unbolted and removed. The refueling canal and the refueling cavity are then flooded with borated water from the refueling water storage tank through the open reactor vessel by gravity feeding or by use of the Residual Heat Removal (RHR) System pumps.

(continued)

BASES

BACKGROUND (continued)

The pumping action of the RHR System into the RCS, and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity provide mixing for the borated coolant in the refueling canal.

The RHR System is in operation during refueling (see LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation—Water Level ≥ 23 Ft," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—Water Level < 23 Ft") to provide forced circulation in the RCS and assist in maintaining the boron concentration in the RCS, the refueling canal, and the refueling cavity above the COLR limit.

APPLICABLE SAFETY ANALYSES

During refueling operations, two types of accidents can occur within containment that affect the fuel and require control of reactivity. These two accident types are a fuel handling accident and a boron dilution event. Both accidents assume that initial core reactivity is at its highest (i.e., at the beginning of the fuel cycle or the end of refueling).

A fuel handling accident can occur during fuel movement in the reactor vessel, the refueling canal, or the refueling cavity and includes a dropped fuel assembly and an incorrectly transferred fuel assembly. The most limiting fuel handling accident is a dropped fuel assembly which is dropped adjacent to other fuel assemblies such that it results in the largest exposure of fuel in the dropped assembly. The negative reactivity effect of the soluble boron compensates for the increased reactivity for both types of accidents. Hence, the boron concentration ensures that $k_{eff} \leq 0.95$ (i.e., 5% $\Delta k/k$ SHUTDOWN MARGIN) during the refueling operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The second type of accident is a boron dilution event which results from inadvertent addition of unborated water to the RCS, refueling cavity, and refueling canal. The assumptions used in the boron dilution event (Ref. 2) provide for a maximum dilution flow of 120 gpm through two charging pumps (i.e., 60 gpm per pump) using unborated water as supplied by the two reactor makeup water pumps (60 gpm per pump). The RCS is also assumed to be at low water levels, uniformly mixed by the RHR System, with the minimum boron concentration as specified in the COLR. The operator has prompt and definite indication of significant boron dilution from an audible count rate function provided by the source range neutron flux instrumentation (see LCO 3.9.2, "Nuclear Instrumentation"). The increased count rate is a function of the effective subcritical multiplication factor. The results of this analysis conclude that an operator has at least 48.8 minutes before SHUTDOWN MARGIN is lost and the reactor goes critical which is sufficient time for operators to mitigate this event. This time is also greater than the 30 minutes required by Reference 3 for dilution events during refueling. Isolating the boron dilution source is performed by closing valves and/or stopping the reactor makeup water pumps.

The RCS boron concentration satisfies Criterion 2 of the NRC Policy Statement.

LCO

The LCO requires that a minimum boron concentration be maintained in the refueling canal, the refueling cavity and the portions of the RCS that are hydraulically coupled with the reactor core while in MODE 6. The boron concentration limit specified in the COLR ensures that a core k_{eff} of ≤ 0.95 is maintained during fuel handling operations and that a core k_{eff} of < 1.0 is maintained during a boron dilution event. Violation of the LCO could lead to an inadvertent criticality during MODE 6.

(continued)

BASES (continued)

APPLICABILITY

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a $k_{eff} \leq 0.95$ during fuel handling operations. In MODES 1 and 2 with $k_{eff} \geq 1.0$, LCO 3.1.4, "Rod Group Alignment Limit," LCO 3.1.5, "Shutdown Bank Insertion Limit," and LCO 3.1.6, "Control Bank Insertion Limits" ensure an adequate amount of negative reactivity is available to shut down the reactor. In MODES 2 with $k_{eff} < 1.0$ and MODES 3, 4, and 5, LCO 3.1.1, "SHUTDOWN MARGIN (SDM)" ensures an adequate amount of negative reactivity is available to maintain the reactor subcritical.

ACTIONS

A.1, A.2, and A.3

If the boron concentration of the filled portions of the RCS, the refueling canal, and the refueling cavity hydraulically coupled to the reactor core, is less than its limit, an inadvertent criticality may occur due to a boron dilution event or incorrect fuel loading. To minimize the potential of an inadvertent criticality resulting from a fuel loading error or an operation that could cause a reduction in boron concentration, CORE ALTERATIONS and positive reactivity additions must be suspended immediately.

Suspension of CORE ALTERATIONS and positive reactivity additions (i.e., other than normal cooldown of the coolant volume for the purpose of system temperature control within established procedures) shall not preclude moving a component to a safe position.

In addition to immediately suspending CORE ALTERATIONS or positive reactivity additions, boration to restore the concentration must be initiated immediately.

There are no safety analysis assumptions of boration flow rate and concentration that must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the operator should begin boration with the best source available for plant conditions.

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

Once action has been initiated, it must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR ensures the coolant boron concentration of the refueling canal, the refueling cavity, and the portions of the RCS that are hydraulically coupled, is within the COLR limits. The boron concentration of the coolant is determined by chemical analysis. The sample should be representative of the portions of the RCS, the refueling canal, and the refueling cavity that are hydraulically coupled with the reactor core.

A Frequency of once every 72 hours is a reasonable amount of time to verify the boron concentration of representative samples. The Frequency is based on operating experience, which has shown 72 hours to be adequate.

REFERENCES

1. Atomic Industrial Forum (AIF) GDC 27, Issued for comment July 10, 1967.
2. UFSAR, Section 15.4.4.2.
3. NUREG-0800, Section 15.4.6.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Nuclear Instrumentation

BASES

BACKGROUND

The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The installed source range neutron flux monitors (N-31 and N-32) are part of the Nuclear Instrumentation System (NIS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core.

The installed source range neutron flux detectors are proportional counters that are filled with boron triflouride (BF_3) gas (Ref. 1). The detectors monitor the neutron flux in counts per second and provide continuous visual indication in the control room. Audible count rate is also available in the control room from either of the source range neutron flux monitors to alert operators to a possible boron dilution event. The NIS is designed in accordance with the criteria presented in Reference 2.

APPLICABLE SAFETY ANALYSES

Two OPERABLE source range neutron flux monitors are required to provide redundant indication to alert operators of unexpected changes in core reactivity. An increase in the audible count rate alerts the operators that a boron dilution event is in progress. Sufficient time is available for the operator to recognize the increase in audible count rate and to terminate the event prior to a loss of SHUTDOWN MARGIN (see Bases for LCO 3.9.1, "Boron Concentration"). Isolating the boron dilution source is performed by closing valves and stopping reactor makeup water pumps.

The source range neutron flux monitors satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

This LCO requires two source range neutron flux monitors be OPERABLE to ensure redundant monitoring capability is available to detect changes in core reactivity.

To be OPERABLE, each monitor must provide visual indication and at least one of the two monitors must provide an audible count rate function in the control room.

APPLICABILITY

In MODE 6, the source range neutron flux monitors must be OPERABLE to determine changes in core reactivity. There are no other direct means available to check core reactivity conditions in this MODE. In MODES 2, 3, 4, and 5, these same installed source range detectors and circuitry are also required to be OPERABLE by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."

ACTIONS

A.1 and A.2

With only one source range neutron flux monitor OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and positive reactivity additions must be suspended immediately. Performance of Required Actions A.1 and A.2 shall not preclude completion of movement of a component to a safe position (i.e., other than normal cooldown of the coolant volume for the purpose of system temperature control within established procedures).

B.1 and B.2

With no source range neutron flux monitor OPERABLE there are no direct means of detecting changes in core reactivity. Therefore, actions to restore a monitor to OPERABLE status shall be initiated immediately and continue until a source range neutron flux monitor is restored to OPERABLE status.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Since CORE ALTERATIONS and positive reactivity additions are not to be made per Required Actions A.1 and A.2, the core reactivity condition is stabilized until the source range neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to ensure the required boron concentration exists.

The Completion Time of 4 hours is sufficient to obtain and analyze coolant samples for boron concentration. The Frequency of once per 12 hours ensures unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this time period.

C.1, C.2, and C.3

With no audible count rate available, only visual indication is available and prompt and definite indication of a boron dilution event has been lost. Therefore, CORE ALTERATIONS and positive reactivity additions must be suspended immediately. Performance of Required Actions C.1 and C.2 shall not preclude completion of movement of a component to a safe position or that is a normal cooldown of the coolant volume for the purpose of system temperature control within established procedures.

Since CORE ALTERATIONS and positive reactivity additions are not to be made, the core reactivity condition is stabilized until the audible count rate capability is restored. This stabilized condition is determined by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

The Completion time of 4 hours is sufficient to obtain and analyze coolant samples for boron concentration. The Frequency of once per 12 hours ensures unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this time period.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

This SR is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one monitor to a similar parameter on another monitor. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range monitors, but each monitor should be consistent with its local conditions.

The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified similarly for the same instruments in LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."

SR 3.9.2.2

This SR is the performance of a CHANNEL CALIBRATION every 24 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the source range neutron flux monitors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to baseline data. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. UFSAR, Section 7.7.3.2.

2. Atomic Industrial Forum (AIF) GDC 13 and 19, Issued for Comment July 10, 1967.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Containment Penetrations

BASES

BACKGROUND

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, a release of fission product radioactivity within containment will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, this is accomplished by maintaining containment OPERABLE as described in LCO 3.6.1, "Containment." In MODE 5, there are no accidents of concern which require containment. In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are closed or capable of being closed. Since there is no potential for containment pressurization, the Appendix J leakage criteria and tests are not required.

The containment serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained within the requirements of 10 CFR 100. Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the equipment hatch must be bolted in place. Good engineering practice dictates that a minimum of 4 bolts be used to hold the equipment hatch in place and that the bolts be approximately equally spaced. As an alternative, the equipment hatch can be isolated by a closure plate that restricts air flow from containment.

(continued)

BASES

BACKGROUND (continued)

The containment equipment and personnel air locks, which are also part of the containment pressure boundary, provide a means for personnel access during MODES 1, 2, 3, and 4 in accordance with LCO 3.6.2, "Containment Air Locks." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of plant shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, containment closure is required; therefore, the door interlock mechanism may remain disabled, but one air lock door must always remain closed in the personnel and equipment hatch (unless the equipment hatch is isolated by a closure plate).

The requirements for containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted from escaping to the environment. The closure restrictions are sufficient to restrict fission product radioactivity release from containment due to a fuel handling accident during refueling.

The Containment Purge and Exhaust System includes two subsystems. The Shutdown Purge System includes a 36 inch purge penetration and a 36 inch exhaust penetration. The second subsystem, a Mini-Purge System, includes a 6 inch purge penetration and a 6 inch exhaust penetration. During MODES 1, 2, 3, and 4, the shutdown purge and exhaust penetrations are isolated by a blind flange with two O-rings that provide the necessary boundary. The two air operated valves in each of the two mini-purge penetrations can be opened intermittently, but are closed automatically by the Containment Ventilation Isolation Instrumentation System. Neither of the subsystems is subject to a Specification in MODE 5.

(continued)

BASES

BACKGROUND (continued)

In MODE 6, large air exchangers are used to support refueling operations. The normal 36 inch Shutdown Purge System is used for this purpose, and each air operated valve is closed by the Containment Ventilation Isolation Instrumentation in accordance with LCO 3.3.5, "Containment Ventilation Isolation Instrumentation."

The Mini-Purge System also remains operational in MODE 6, and all four valves are also closed by the Containment Ventilation Isolation Instrumentation.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations during fuel movements.

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the most severe radiological consequences result from a fuel handling accident. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 1). Fuel handling accidents, analyzed using the criteria of Reference 2, include dropping a single irradiated fuel assembly and handling tool or a heavy object onto other irradiated fuel assemblies. The requirements of LCO 3.9.6, "Refueling Cavity Water Level," and the minimum decay time of 100 hours prior to CORE ALTERATIONS ensure that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are within the guideline values specified in 10 CFR 100. Standard Review Plan (SRP), Section 15.7.4, Rev. 1 (Ref. 2), requires containment closure even though this is not an assumption of the accident analyses. The acceptance limits for offsite radiation exposure is 96 rem (Ref. 3).

Containment penetrations satisfy Criterion 3 of the NRC Policy Statement since these are assumed in the SRP.

(continued)

BASES (continued)

LCO

This LCO limits the consequences of a fuel handling accident in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment purge and exhaust penetrations. For the OPERABLE containment purge and exhaust penetrations, this LCO ensures that at least one valve in each of these penetrations is isolable by the Containment Ventilation Isolation System.

APPLICABILITY

The containment penetration requirements are applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment because this is when there is a potential for a fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1. In MODES 5 and 6, when CORE ALTERATIONS or movement of irradiated fuel assemblies within containment are not being conducted, the potential for a fuel handling accident does not exist. Therefore, under these conditions, no requirements are placed on containment penetration status.

ACTIONS

A.1 and A.2

If the containment equipment hatch (or its closure plate), air lock doors, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, including the Containment Ventilation Isolation System not capable of automatic actuation when the purge and exhaust valves are open, the plant must be placed in a condition where the isolation function is not needed. This is accomplished by immediately suspending CORE ALTERATIONS and movement of irradiated fuel assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

This SR demonstrates that each of the containment penetrations required to be in its closed position is in that position. The Surveillance on the open purge and exhaust valves will demonstrate that the valves are not blocked or otherwise prevented from closing (e.g., solenoid unable to vent).

The Surveillance is performed every 7 days during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. The Surveillance interval is selected to be commensurate with the normal duration of time to complete fuel handling operations. As such, this Surveillance ensures that a postulated fuel handling accident that releases fission product radioactivity within the containment will not result in a release of fission product radioactivity to the environment.

SR 3.9.3.2

This SR demonstrates that each containment purge and exhaust valve actuates to its isolation position on manual initiation or on an actual or simulated high radiation signal. The 24 month Frequency maintains consistency with other similar instrumentation and valve testing requirements. In LCO 3.3.5, the Containment Ventilation Isolation instrumentation requires a CHANNEL CHECK every 12 hours and a COT every 92 days to ensure the channel OPERABILITY during refueling operations. Every 24 months an ACTUATION LOGIC TEST and CHANNEL CALIBRATION is performed. These Surveillances will ensure that the valves are capable of closing after a postulated fuel handling accident to limit a release of fission product radioactivity from the containment.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 15.7.
2. NUREG-800, Section 15.7.4, Rev. 1, July 1981.
3. Letter from D. M. Crutchfield, NRC, to J. Maier, RG&E, Subject: "Fuel Handling Accident Inside Containment," dated October 7, 1981.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Residual Heat Removal (RHR) and Coolant Circulation — Water Level ≥ 23 Ft

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), and to provide mixing of the borated coolant to prevent thermal and boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchanger(s) where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS loop "B" cold leg. Operation of the RHR System for normal cooldown or decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and bypass line(s). Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

The safety analysis for the boron dilution event during refueling assumes one RHR loop is in operation (Ref. 2). This initial assumption ensures continuous mixing of the borated coolant in the reactor vessel. The analysis also assumes the RCS is at equilibrium boron concentration and dilution occurs uniformly throughout the system. Therefore, thermal or boron stratification is not postulated. In order to ensure adequate mixing of the borated coolant, one loop of the RHR System is required to be OPERABLE, and in operation while in MODE 6, with water level ≥ 23 ft above the top of the reactor vessel flange.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

While there is no explicit analysis assumption for the decay heat removal function of the RHR System in MODE 6, if the reactor coolant temperature is not maintained, boiling of the coolant could result. Due to the water volume available in the RCS with a water level ≥ 23 ft above the top of the reactor vessel flange, a significant amount of time exists before boiling of the coolant would occur following a loss of the required RHR pump. Since the loss of the required RHR pump results in the requirement to suspend operations involving a reduction in reactor coolant boron concentration, a boron dilution event is very unlikely. Therefore, this requirement dictates that single failures are not considered for this LCO due to the time available to operators to respond to a loss of the operating RHR pump.

The LCO permits de-energizing the required RHR pump for short durations provided no operations are permitted that would cause a reduction in the RCS boron concentration. This conditional de-energizing of the required RHR pump does not result in a challenge to the fission product barrier or result in coolant stratification.

RHR and Coolant Circulation—Water Level ≥ 23 Ft satisfies criterion 2 of the NRC Policy Statement.

LCO

Only one RHR loop is required for decay heat removal in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, because the volume of water above the reactor vessel flange provides backup decay heat removal capability. One RHR loop is required to be OPERABLE and in operation to provide mixing of borated coolant to minimize the possibility of criticality.

An OPERABLE RHR loop includes an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. The flow path starts in the RCS loop "A" hot leg and is returned to the RCS loop "B" cold leg.

(continued)

BASES

LCO (continued)

The LCO is modified by a Note that allows the required operating RHR loop to be removed from service for up to 1 hour per 8 hour period provided no operations are permitted that would cause a reduction of the RCS boron concentration. Boron reduction is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This allows the operator to view the core and permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles. This also permits operations such as RCS to RHR isolation valve testing. During this 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling cavity. Should both RHR loops become inoperable at anytime during operation in accordance with this Note, the Required Actions of this LCO should be immediately taken.

APPLICABILITY

One RHR loop must be OPERABLE and in operation in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to provide decay heat removal and mixing of the borated coolant. The 23 ft water level was selected because it corresponds to the 23 ft requirement established for fuel movement in LCO 3.9.6, "Refueling Cavity Water Level."

Requirements for the RHR System in MODES 1, 2, 3, 4, and 5 are covered by LCO 3.4.4, "RCS Loops—MODE 1 > 8.5% RTP;" LCO 3.4.5, "RCS Loops—MODES 1 ≤ 8.5% RTP, 2 and 3;" LCO 3.4.6, "RCS Loops—MODE 4;" LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled;" and LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled." The RHR loop requirements in MODE 6 with the water level < 23 ft are located in LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—Water Level < 23 Ft."

(continued)

BASES (continued)

ACTIONS

A.1, A.2, and A.3

If RHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations can occur by the addition of water with a lower boron concentration than that contained in the RCS. Therefore, actions that could result in a reduction in the coolant boron concentration must be suspended immediately.

With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level of 23 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase decay heat load, such as loading a fuel assembly, is a prudent action under this condition. Therefore, actions shall be taken immediately to suspend loading irradiated fuel assemblies in the core.

With the plant in MODE 6 and the refueling water level ≥ 23 ft above the top of the reactor vessel flange, removal of decay heat is by ambient losses only. Therefore, corrective actions shall be initiated immediately and shall continue until RHR loop requirements are satisfied.

A.4

If RHR loop requirements are not met, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This SR requires verification every 12 hours that one RHR loop is in operation and circulating reactor coolant. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing decay heat removal capability and mixing of the borated coolant to prevent thermal and boron stratification in the core. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

REFERENCES

1. UFSAR, Section 5.4.5.
2. UFSAR, Section 15.4.4.2.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Residual Heat Removal (RHR) and Coolant Circulation—Water Level < 23 Ft

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), and to provide mixing of the borated coolant to prevent thermal and boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchanger(s) where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS loop "B" cold leg. Operation of the RHR System for normal cooldown or decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and bypass line(s). Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

The safety analysis for the boron dilution event during refueling assumes one RHR loop is in operation (Ref. 2). This initial assumption ensures continuous mixing of the borated coolant in the reactor vessel. The analysis also assumes the RCS is at equilibrium boron concentration and dilution occurs uniformly throughout the system. Therefore, thermal or boron stratification is not postulated.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

While there is no explicit analysis assumption for the decay heat removal function of the RHR System in MODE 6, if the reactor coolant temperature is not maintained, boiling of the coolant could result. This could lead to a loss of coolant in the reactor vessel. In addition, boiling of the coolant could lead to a reduction in boron concentration in the coolant due to boron plating out on components near the areas of the boiling activity. The loss of coolant and the reduction of boron concentration in the reactor coolant could eventually challenge the integrity of the fuel cladding, which is a fission product barrier.

In order to prevent a challenge to fuel cladding and to ensure adequate mixing of the borated coolant, two loops of the RHR System are required to be OPERABLE, and one loop in operation while in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange.

RHR and Coolant Circulation—Water Level < 23 Ft satisfies criterion 4 of the NRC Policy Statement.

LCO

Both RHR loops must be OPERABLE in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange. In addition, one RHR loop must be in operation in order to remove decay heat and provide mixing of borated coolant to minimize the possibility of criticality.

An OPERABLE RHR loop includes an RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path. The flow path starts in the RCS loop "A" hot leg and is returned to the RCS loop "B" cold leg.

APPLICABILITY

Two RHR loops are required to be OPERABLE, and one RHR loop must be in operation in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, to provide decay heat removal and mixing of the borated coolant.

(continued)

BASES

APPLICABILITY (continued)

Requirements for the RHR System in MODES 1, 2, 3, 4, and 5 are covered by LCO 3.4.4, "RCS Loops—MODE 1 > 8.5% RTP;" LCO 3.4.5, "RCS Loops—MODES 1 ≤ 8.5% RTP, 2 and 3;" LCO 3.4.6, "RCS Loops—MODE 4;" LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled;" and LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled." The RHR loop requirements in MODE 6 with the water level ≥ 23 ft are located in LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation—Water Level ≥ 23 Ft."

ACTIONS

A.1 and A.2

If less than the required number of RHR loops are OPERABLE, action shall be immediately initiated and continued until the RHR loop is restored to OPERABLE status and operation or until ≥ 23 ft of water level is established above the reactor vessel flange. When the water level is ≥ 23 ft above the reactor vessel flange, the Applicability changes to that of LCO 3.9.4, and only one RHR loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

B.1 and B.2

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations. The potential for reduced boron concentrations by the addition of water with a lower boron concentration than that contained in the RCS must be reduced to prevent a criticality event. Therefore, operations involving a reduction in RCS boron concentration must be suspended immediately. Actions shall also be initiated immediately, and continued, to restore one RHR loop to operation. Since the plant is in Conditions A and B concurrently, the restoration of two OPERABLE RHR loops and one operating RHR loop should be accomplished expeditiously.

(continued)

BASES (continued)

ACTIONS (continued)

B.3

If no RHR loop is in operation, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures that dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This SR requires verification every 12 hours that one RHR loop is in operation and circulating reactor coolant. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing decay heat removal capability and mixing of the borated coolant to prevent thermal and boron stratification in the core. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.9.5.2

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the standby pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 5.4.5.
2. UFSAR, Section 15.4.4.2.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Refueling Cavity Water Level

BASES

BACKGROUND

The movement of irradiated fuel assemblies within containment or performance of CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts, requires a minimum water level of 23 ft above the top of the reactor vessel flange. This requirement ensures a sufficient level of water is maintained in the refueling cavity or portions hydraulically connected (e.g., refueling canal) to retain iodine fission product activity resulting from a fuel handling accident in containment (Ref. 1). The retention of iodine activity by the water limits the offsite dose from the accident well within the values specified in 10 CFR 100 (Ref. 2).

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS and movement of irradiated fuel assemblies, the water level in the refueling cavity is an initial condition design parameter in the analysis of a fuel handling accident in containment (Ref. 1). A minimum water level of 23 ft allows a decontamination factor of 100 to be used in the accident analysis for iodine (Ref. 3). This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory (Ref. 3).

With a minimum water level of 23 ft and a minimum decay time of 100 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses are maintained within allowable limits (Ref. 2).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Refueling cavity water level satisfies Criterion 2 of the NRC Policy Statement.
LCO	A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits and preserves the assumptions of the fuel handling accident analysis (Ref. 1). As such, it is the minimum required level during movement of fuel assemblies within containment. Maintaining this minimum water level in the refueling cavity also ensures that ≥ 23 ft of water is available in the spent fuel pool during fuel movement assuming that containment and Auxiliary Building atmospheric pressures are equal.
APPLICABILITY	This LCO is applicable when moving irradiated fuel assemblies within containment. This LCO is also applicable during CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts. The LCO ensures a sufficient level of water is present in the refueling cavity to minimize the radiological consequences of a fuel handling accident in containment. Requirements for fuel handling accidents in the spent fuel pool are covered by LCO 3.7.11, "Spent Fuel Pool (SFP) Water Level."
ACTIONS	<u>A.1 and A.2</u> When the initial condition assumed in the fuel handling accident cannot be met, steps should be taken to preclude the accident from occurring. With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving CORE ALTERATIONS or movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

The suspension of CORE ALTERATIONS and fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum refueling cavity water level of 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 1).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls of valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. UFSAR, Section 15.7.3.3.
2. 10 CFR 100.
3. Regulatory Guide 1.25.

4.0 DESIGN FEATURES

4.1 Site Location

The site for the R.E. Ginna Nuclear Power Plant is located on the south shore of Lake Ontario, approximately 16 miles east of Rochester, New York.

The exclusion area boundary distances from the plant shall be as follows:

Direction	Distance (m)
N (including offshore)	8000
NNE	8000
NE	8000
ENE	8000
E	747
ESE	640
SE	503
SSE	450
S	450
SSW	450
SW	503
WSW	915
W	945
WNW	701
NW	8000
NNW	8000

4.2 Reactor Core

4.2.1 Fuel Assemblies

The reactor shall contain 121 fuel assemblies. Each assembly shall consist of a matrix of zircalloy clad fuel rods with an initial composition of natural or slightly enriched uranium dioxide (UO_2) as fuel material. Limited substitutions of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in nonlimiting core regions.

(continued)

4.0 DESIGN FEATURES

4.2 Reactor Core (continued)

4.2.2 Control Rod Assemblies

The reactor core shall contain 29 control rod assemblies. The control material shall be silver indium cadmium.

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.05 weight percent;

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 9.1 of the UFSAR;

c. Consolidated rod storage canisters may be stored in the spent fuel storage racks provided that the fuel assemblies from which the rods were removed meet all the requirements of LCO 3.7.13 for the region in which the canister is to be stored. However, the consolidated rod storage canister located in Region RGAF2 may exceed these requirements. The average decay heat of the fuel assembly from which the rods were removed for all consolidated fuel assemblies must also be ≤ 2150 BTU/hr.

4.3.1.2 The new fuel storage dry racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.05 weight percent;

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 9.1 of the UFSAR; and

c. $k_{eff} \leq 0.98$ if moderated by aqueous foam, which includes an allowance for uncertainties as described in Section 9.1 of the UFSAR.

(continued)

4.0 DESIGN FEATURES (continued)

4.3 Fuel Storage (continued)

4.3.2 Drainage

The spent fuel pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 257'0" (mean sea level).

4.3.3 Capacity

The spent fuel pool is designed and shall be maintained with a storage capacity limited to no more than 1016 fuel assemblies.

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The plant manager shall be responsible for overall plant operation and shall delegate in writing the succession to this responsibility during his absence.

The plant manager, or his designee, shall approve prior to implementation, each proposed test, experiment or modification to structures, systems or components that affect nuclear safety.

5.1.2 The Shift Supervisor (SS) shall be responsible for the control room command function. During any absence of the SS from the control room while the plant is in MODE 1, 2, 3, or 4, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the SS from the control room while the plant is in MODE 5 or 6, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for plant operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting the safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements, including the plant specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications, shall be documented in the UFSAR;

b. The plant manager shall report to the corporate vice president specified in 5.2.1.c, shall be responsible for overall safe operation of the plant, and shall have control over those onsite activities necessary for safe operation and maintenance of the plant; and

c. A corporate vice president shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety.

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

(continued)

5.2 Organization (continued)

5.2.2 Plant Staff

The plant staff organization shall include the following:

a. An auxiliary operator shall be assigned to the shift crew with fuel in the reactor. An additional auxiliary operator shall be assigned to the shift crew while the plant is in MODE 1, 2, 3 or 4.

b. Shift crew composition may be one less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and Specifications 5.2.2.a and 5.2.2.f for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

c. An individual qualified in radiation protection procedures shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

d. The amount of overtime worked by plant staff members performing safety related functions shall be limited and controlled in accordance with a NRC approved program specified in plant procedures changes to the guidelines in these procedures shall be submitted to the NRC for review.

e. The operations manager or operations middle manager shall hold a SRO license.

f. The Shift Technical Advisor (STA) shall provide advisory technical support to the Shift Supervisor (SS) in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the plant. The STA shall be assigned to the shift crew while the plant is in MODE 1, 2, 3 or 4 and shall meet the qualifications contained in the STA training program specified in UFSAR Section 13.2.

5.0 ADMINISTRATIVE CONTROLS

5.3 Plant Staff Qualifications

5.3.1 Each member of the plant staff shall meet or exceed the minimum qualifications of ANSI Standard N18.1-1971, as supplemented by Regulatory Guide 1.8, Revision 1, September 1975, for comparable positions.

5.0 ADMINISTRATIVE CONTROLS

5.4 Procedures

5.4.1 Written procedures shall be established, implemented, and maintained covering the following activities:

a. The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978;

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1, as stated in Generic Letter 82-33;

c. Effluent and environmental monitoring;

d. Fire Protection Program implementation; and

e. All programs specified in Specification 5.5.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs and Manuals

The following programs and manuals shall be established, implemented, and maintained.

5.5.1 Offsite Dose Calculation Manual (ODCM)

a. The ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program; and

b. The ODCM shall also contain the radioactive effluent controls and radiological environmental monitoring activities and descriptions of the information that should be included in the Annual Radiological Environmental Operating and Radioactive Effluent Release Reports.

Licensee initiated changes to the ODCM:

a. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

   1. sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s),

   2. a determination that the change(s) maintain the levels of radioactive effluent control required by 10 CFR 20.1302, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and does not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations;

b. Shall become effective after review and acceptance by the onsite review function and the approval of the plant manager; and

(continued)

5.5 Programs and Manuals

5.5.1 ODCM (continued)

c. Shall be submitted to the NRC in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Radioactive Effluent Release Report for the period of the report in which any change in the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (i.e., month and year) the change was implemented.

5.5.2 Primary Coolant Sources Outside Containment Program

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident. The systems include Containment Spray, Safety Injection, and Residual Heat Removal in the recirculation configuration. The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at refueling cycle intervals or less.

5.5.3 Post Accident Sampling Program

This program provides controls that ensure the capability to obtain and analyze reactor coolant, radioactive gases, and particulates in plant gaseous effluents and containment atmosphere samples under accident conditions. The program shall include the following:

a. Training of personnel;

b. Procedures for sampling and analysis; and

c. Provisions for maintenance of sampling and analysis equipment.

(continued)

5.5 Programs and Manuals (continued)

5.5.4 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM;

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to ten times the concentration values in 10 CFR 20, Appendix B, Table 2, Column 2;

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from the plant to unrestricted areas, conforming to 10 CFR 50, Appendix I and 40 CFR 141;

e. Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days;

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

(continued)

5.5 Programs and Manuals (continued)

5.5.4 Radioactive Effluent Controls Program (continued)

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary conforming to the dose associated with 10 CFR 20, Appendix B, Table 2, Column 1;

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from the plant to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from the plant to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

5.5.5 Component Cyclic or Transient Limit Program

This program provides controls to track the reactor coolant system cyclic and transient occurrences specified in UFSAR Table 5.1-4 to ensure that components are maintained within the design limits.

5.5.6 Pre-Stressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in pre-stressed concrete containments, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. The Tendon Surveillance Program, inspection frequencies, and acceptance criteria shall be in accordance with Regulatory Guide 1.35, Revision 2.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Tendon Surveillance Program inspection frequencies.

(continued)

5.5 Programs and Manuals (continued)

5.5.7 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components including applicable supports. The program shall include the following:

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as follows:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

(continued)

5.5 Programs and Manuals (continued)

5.5.8 Steam Generator (SG) Tube Surveillance Program

Each SG shall be demonstrated OPERABLE by performance of an inservice inspection program in accordance with the Nuclear Policy Manual. This inspection program shall define the specific requirements of the edition and Addenda of the ASME Boiler and Pressure Code, Section XI, as required by 10 CFR 50.55a(g). The program shall include the following:

a. The inspection intervals for SG tubes shall be specified in the Inservice Inspection Program.

b. SG tubes that have imperfections > 40% through wall, as indicated by eddy current, shall be repaired by plugging or sleeving.

c. SG sleeves that have imperfections > 30% through wall, as indicated by eddy current, shall be repaired by plugging.

5.5.9 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. This program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

(continued)

5.5 Programs and Manuals (continued)

5.5.10 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature filter ventilation systems and the Spent Fuel Pool (SFP) Charcoal Adsorber System. The test frequencies and methods will be in accordance with Regulatory Guide 1.52, Revision 2, except that in lieu of 18 month test intervals, a 24 month interval will be implemented.

a. Containment Post-Accident Charcoal System

1. Demonstrate the pressure drop across the charcoal adsorber bank is < 3 inches of water at a design flow rate (± 10%).

2. Demonstrate that an in-place Freon test of the charcoal adsorber bank shows a penetration and system bypass < 1.0%, when tested under ambient conditions.

3. Demonstrate for a carbon sample that a laboratory analysis shows the iodine removal efficiency of ≥ 90% of radioactive methyl iodide.

b. Containment Recirculation Fan Cooler System

1. Demonstrate the pressure drop across the high efficiency particulate air (HEPA) filter bank is < 3 inches of water at a design flow rate (± 10%).

2. Demonstrate that an in-place dioctylphthalate (DOP) test of the HEPA filter bank shows a penetration and system bypass < 1.0%.

c. Control Room Emergency Air Treatment System (CREATS)

1. Demonstrate the pressure drop across the HEPA filter bank is < 3 inches of water at a design flow rate (± 10%).

2. Demonstrate that an in-place DOP test of the HEPA filter bank shows a penetration and system bypass < 1.0%.

(continued)

5.5 Programs and Manuals (continued)

5.5.10 VFTP (continued)

3. Demonstrate the pressure drop across the charcoal adsorber bank is < 3 inches of water at a design flow rate (± 10%).

4. Demonstrate that an in-place Freon test of the charcoal adsorber bank shows a penetration and system bypass < 1.0%, when tested under ambient conditions.

5. Demonstrate for a carbon sample that a laboratory analysis shows the iodine removal efficiency of ≥ 90% of radioactive methyl iodide.

d. SFP Charcoal Adsorber System

1. Demonstrate that the total air flow rate from the charcoal adsorbers shows at least 75% of that measured with a complete set of new adsorbers.

2. Demonstrate that an in-place Freon test of the charcoal adsorbers bank shows a penetration and system bypass < 1.0%, when tested under ambient conditions.

3. Demonstrate for a carbon sample that a laboratory analysis shows the iodine removal efficiency of ≥ 90% of radioactive methyl iodide.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP frequencies.

(continued)

5.5 Programs and Manuals (continued)

5.5.11 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the waste gas decay tanks and the quantity of radioactivity contained in waste gas decay tanks. The gaseous radioactivity quantities shall be determined following the methodology in NUREG-0133.

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the waste gas decay tanks and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion); and

b. A surveillance program to ensure that the quantity of radioactivity contained in each waste gas decay tank is less than the amount that would result in a whole body exposure of ≥ 0.5 rem to any individual in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.12 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

    1. an API gravity or an absolute specific gravity within limits,

    2. a flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

(continued)

5.5 Programs and Manuals (continued)

5.5.12 Diesel Fuel Oil Testing Program (continued)

3. a clear and bright appearance with proper color; and

b. Within 31 days following addition of the new fuel to the storage tanks, verify that the properties of the new fuel oil, other than those addressed in a. above, are within limits for ASTM 2D fuel oil.

5.5.13 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not involve either of the following:

1. A change in the TS incorporated in the license; or

2. A change to the UFSAR or Bases that involves an unreviewed safety question as defined in 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

d. Proposed changes that meet the criteria of Specification 5.5.13.b.1 or Specification 5.5.13.b.2 shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71e.

(continued)

5.5 Programs and Manuals (continued)

5.5.14 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to the supported system(s) is also inoperable; or

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the inoperable support system(s) for the supported systems (a) and (b) above is also inoperable.

(continued)

5.5 Programs and Manuals

5.5.14 SFDP (continued)

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.15 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 60 psig.

The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.2% of containment air weight per day.

Leakage Rate acceptance criteria are:

a. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first plant startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and Type C tests and $\leq 0.75\ L_a$ for Type A tests;

b. Air lock testing acceptance criteria are:

   1) For each air lock, overall leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$, and

   2) For each door, leakage rate is $\leq 0.01\ L_a$ when tested at $\geq P_a$.

c. Mini-purge valve acceptance criteria is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program.

The provisions of SR 3.0.3 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program.

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 Occupational Radiation Exposure Report

A tabulation on an annual basis of the number of station, utility, and other personnel (including contractors) receiving exposures > 100 mrem/yr and their associated man rem exposure according to work and job functions (e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance, waste processing, and refueling). This tabulation supplements the requirements of 10 CFR 20.2206. The dose assignments to various duty functions may be estimated based on pocket dosimeter, thermoluminescent dosimeter (TLD), or film badge measurements. Small exposures totalling < 20% of the individual total dose need not be accounted for. In the aggregate, at least 80% of the total whole body dose received from external sources should be assigned to specific major work functions. The report shall be submitted on or before April 30 of each year.

5.6.2 Annual Radiological Environmental Operating Report

The Annual Radiological Environmental Operating Report covering the operation of the plant during the previous calendar year shall be submitted by May 15 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the radiological environmental monitoring activities for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

(continued)

5.6 Reporting Requirements (continued)

5.6.3 Radioactive Effluent Release Report

The Radioactive Effluent Release Report covering the operation of the plant shall be submitted in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the plant. The material provided shall be consistent with the objectives outlined in the ODCM and in conformance with 10 CFR 50.36a and 10 CFR 50, Appendix I, Section IV.B.1.

5.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the pressurizer power operated relief valves or pressurizer safety valves, shall be submitted on a monthly basis no later than the 15th of each month following the calendar month covered by the report.

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

LCO 3.1.1, "SHUTDOWN MARGIN (SDM)";
LCO 3.1.3, "MODERATOR TEMPERATURE COEFFICIENT (MTC)";
LCO 3.1.5, "Shutdown Bank Insertion Limit";
LCO 3.1.6, "Control Bank Insertion Limits";
LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)";
LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)";
LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)";
LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; and
LCO 3.9.1, "Boron Concentration."

(continued)

5.6 Reporting Requirements

5.6.5 COLR (continued)

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.
   (Methodology for LCO 3.1.1, LCO 3.1.3, LCO 3.1.5, LCO 3.1.6, LCO 3.2.1, LCO 3.2.2, LCO 3.2.3, and LCO 3.9.1.)

2. WCAP-9220-P-A, "Westinghouse ECCS Evaluation Model-1981 Version," Revision 1, February 1982.
   (Methodology for LCO 3.2.1.)

3. WCAP-8385, "Power Distribution Control and Load Following Procedures - Topical Report," September 1974.
   (Methodology for LCO 3.2.3.)

4. WCAP-8567-P-A, "Improved Thermal Design Procedure," February 1989.
   (Methodology for LCO 3.4.1 when using ITDP.)

5. WCAP 11397-P-A, "Revised Thermal Design Procedure," April 1989.
   (Methodology for LCO 3.4.1 when using RTDP.)

6. WCAP-10054-P-A and WCAP-10081, "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," August 1985.
   (Methodology for LCO 3.2.1)

7. WCAP-10924-P-A, Volume 1, Rev. 1, and Addenda 1,2,3, "Westinghouse Large-Break LOCA Best-Estimate Methodology, Volume 1: Model Description and Validation," December 1988.
   (Methodology for LCO 3.2.1)

8. WCAP-10924-P-A, Volume 2, Rev. 2, and Addenda, "Westinghouse Large-Break LOCA Best-Estimate Methodology, Volume 2: Application to Two-Loop PWRs Equipped with Upper Plenum Injection," December 1988.
   (Methodology for LCO 3.2.1)

(continued)

5.6 Reporting Requirements

5.6.5 COLR (continued)

9. WCAP-10924-P-A, Rev. 2 and WCAP-12071, "Westinghouse Large-Break LOCA Best Estimate Methodology, Volume 2: Application to Two-Loop PWRs Equipped With Upper Plenum Injection, Addendum 1: Responses to NRC Questions," December 1988.
(Methodology for LCO 3.2.1)

10. WCAP-10924-P, Volume 1, Rev. 1, Addendum 4, "Westinghouse LBLOCA Best Estimate Methodology; Model Description and Validation; Model Revisions," August 1990.
(Methodology for LCO 3.2.1)

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heatup, cooldown, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits"

b. The power operated relief valve lift settings required to support the Low Temperature Overpressure Protection (LTOP) System, and the LTOP enable temperature shall be established and documented in the PTLR for the following:

LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled";
LCO 3.4.10, "Pressurizer Safety Valves"; and
LCO 3.4.12, "LTOP System."

(continued)

5.6 Reporting Requirements

5.6.6 PTLR (continued)

c. The RCS pressure and temperature and LTOP limits shall be those previously reviewed and approved by the NRC in Amendment No. 48. The acceptability of the P/T and LTOP limits are documented in NRC letter, "R.E. Ginna - Acceptance for Referencing of Pressure Limits Report," December 26, 1995. Specifically, the limits and methodology are described in the following documents:

1. Amendment No. 48 to Facility Operating License No. DPR-18, R.E. Ginna Nuclear Power Plant, March 6, 1992.

2. Letter from C.I. Grimes, NRC, to R.A. Newton, Westinghouse Electric Corporation, "Acceptance for Referencing Topical Report WCAP-14040, Revision 1, 'Methodology used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves'," October 16, 1995.

3. Letter from R.C. Mecredy, Rochester Gas and Electric Corporation (RG&E), to Document Control Desk, NRC, Attention A.R. Johnson, "Technical Specifications Improvement Program, Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)," December 8, 1995.

d. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluency period and for revisions or supplement thereto.

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

5.7.1 Pursuant to 10 CFR 20, paragraph 20.1601(a), in lieu of the requirements of 10 CFR 20.1601(c), each high radiation area, as defined in 10 CFR 20, in which the intensity of radiation is > 100 mrem/hr but ≤ 1000 mrem/hr at a distance of 30 cm, shall be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (RWP). Individuals qualified in radiation protection procedures (e.g., radiation protection technicians) or personnel continuously escorted by such individuals may be exempt from the RWP issuance requirement during the performance of their assigned duties in high radiation areas with exposure rates ≤ 1000 mrem/hr, provided they are otherwise following plant radiation protection procedures for entry into such high radiation areas.

Any individual or group of individuals permitted to enter such areas shall be provided with or accompanied by one or more of the following:

a. A radiation monitoring device that continuously indicates the radiation dose rate in the area.

b. A radiation monitoring device that continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel are aware of them.

c. An individual qualified in radiation protection procedures with a radiation dose rate monitoring device, who is responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified by the radiation protection technician in the RWP.

(continued)

5.7 High Radiation Area (continued)

5.7.2 In addition to the requirements of Specification 5.7.1, areas with radiation levels > 1000 mrem/hr at a distance of 30 cm shall be provided with locked or continuously guarded doors to prevent unauthorized entry and the keys shall be maintained under the administrative control of the Shift Supervisor on duty or radiation protection supervision. Doors shall remain locked except during periods of access by personnel under an approved RWP that shall specify the dose rate levels in the immediate work areas and the maximum allowable stay times for individuals in those areas. In lieu of the stay time specification of the RWP, direct or remote (such as closed circuit TV cameras) continuous surveillance may be made by personnel qualified in radiation protection procedures to provide positive exposure control over the activities being performed within the area.

5.7.3 In addition to the requirements of Specification 5.7.1, for individual high radiation areas with radiation levels of > 1000 mrem/hr at a distance of 30 cm, accessible to personnel, that are located within large areas such as reactor containment, where no enclosure exists for purposes of locking, or that cannot be continuously guarded, and where no enclosure can be reasonably constructed around the individual area, that individual area shall be barricaded and conspicuously posted, and a flashing light shall be activated as a warning device.