10 CFR 50.59(d)(2)
L-2018-100
APR 2 5 2018

U. S. Nuclear Regulatory Commission
Attn.: Document Control Desk
Washington, D.C. 20555-0001

Re: Turkey Point Units 3 and 4
Docket Nos. 50-250 and 50-251
10 CFR 50.59(d)(2) Summary Report

In accordance with the requirements of 10 CFR 50.59(d)(2), a summary report of changes, tests and experiments subject to 10 CFR 50.59 evaluation covering the period from April 29, 2016 to October 31, 2017 is provided in Sections 1 and 2 of Attachment 1. The report addresses the 10 CFR 50.59 evaluations for design change packages and temporary modifications, and engineering evaluations.

Section 3 of the Attachment 1 report contains a summary of Technical Specification (TS) Bases changes from January 25, 2017 to current. The updated TS Bases are controlled and contained in Attachments 1 (index) and 2 (bases) to Turkey Point Administrative Procedure No. 0-ADM-536, Technical Specification Bases Control Program. Attachments 1 and 2 of procedure 0-ADM-536 are contained in Attachment 2 to this letter.

Should you have any questions regarding this submission, please contact Mr. Robert Hess, Licensing Manager, at 305-246-4112.

Sincerely,

Robert Coffey
Regional Vice President – Southern Region
Turkey Point Nuclear Plant

Attachments: 1) 10 CFR 50.59(d)(2) Summary Report
2) Technical Specification Bases Control Program, Procedure 0-ADM-536, Attachments 1 and 2

cc: Regional Administrator, Region II, USNRC
Senior Resident Inspector, USNRC, Turkey Point Plant

Attachment 1

Unit 4 Cycle 29

10 CFR 50.59 Summary Report

Changes, Tests, and Experiments

Allowed by 10 CFR 50.59

For the Period Covering

April 29, 2016 to October 31, 2017

Florida Power & Light Company

Turkey Point Units 3 and 4

Docket Numbers 50-250 and 50-251

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INTRODUCTION

This report is divided into three (3) sections. Section 1 summarizes changes made to the facility as described in the Updated Final Safety Analysis Report (UFSAR) resulting from Design Change Packages (DCPs) and Temporary Configuration Changes (TCCs) that screened in for evaluation under 10 CFR 50.59. Section 2 summarizes changes made to the facility or procedures as described in the UFSAR which were justified by a stand-alone 10 CFR 50.59 evaluation, not performed as part of a DCP or TCC.

Each of the Engineering Change (EC) documents is presented with an overall summary of the associated activity and a summary of the 10 CFR 50.59 evaluation(s) (SE). Each EC package summary indicates the revision level(s) of the completed 10 CFR 50.59evaluation(s) and the revision level(s) of the associated EC package. Example: An EC package may have dozens of revisions but only one or two revisions of the evaluation, e.g., Revision 0 of a SE could correspond to Revision 2 of the EC while Revision 1 of the SE could correspond to Revision 10 of the EC.

Section 3 provides a summary of the Technical Specification Bases changes made since the previous submission of the report.

SECTION 1

DESIGN CHANGE PACKAGES/TEMPORARY MODIFICATIONS

SUMMARY FOR SECTION 1: DESIGN CHANGE PACKAGES / TEMPORARY MODIFICATIONS

10 CFR 50.59(d)(2) requires that each licensee submit a periodic report containing a brief description of any changes, tests, and experiments made or conducted at their facility under the criteria of 10 CFR 50.59(c)(2). This report is also required to include a summary of the evaluation of each change, test, or experiment. Florida Power & Light Company is committed to submitting this report for the Turkey Point facility on an approximate eighteen month periodicity beginning six months after each Unit 4 refueling outage.

The report contained herein covers the period between April 29, 2016 and October 31, 2017. During this period, there were 2 permanent and 1 temporary plant modifications evaluated under the criteria of 10 CFR 50.59(c)(2) that were completely implemented and turned over to the station. A description of each is included in this section along with a summary of the applicable 10 CFR 50.59 evaluation.

DESIGN CHANGE PACKAGE EC 283225
Revision 11

UNIT: 3 & 4
UNIT 3 & UNIT 4 CCW SUPPLEMENTAL COOLING

SUMMARY:

This Design Change Package (DCP) installed a new supplemental cooling system (SCS) as an addition to the Component Cooling Water (CCW) system to provide additional cooling to the containment building atmosphere. The SCS provided supplemental cooling to the Unit 3 and Unit 4 CCW system by injecting cooled water into the existing Unit 4 Boric Acid Evaporator (BAE) connections upstream of the Normal Containment Coolers (NCCs).

10 CFR 50.59 Evaluation:

This change does not require prior NRC approval in accordance with 10 CFR 50.59(c)(1). Implementation of the CCW SCS was demonstrated to meet all plant design basis requirements. Existing system and component temperature limits were maintained for all postulated accident and malfunction scenarios.

DESIGN CHANGE PACKAGE EC 280401
Revision 14

UNIT: 3 & 4
Unit 4 - RCP Seals Upgrade Project

SUMMARY:

This Design Change Package (DCP) provides the design justification and the associated modifications required for replacement of the shaft seals on all three Reactor Coolant Pumps (RCPs) 4P200A/B/C for Unit 4. The existing Areva/Westinghouse shaft seals are being replaced with low-leakage Flowserve N-Seals (specifically model NX seals). This change package supports the Flexible and Diverse Strategies (FLEX) for beyond Design Basis External Events (BDBEEs) and the site's transition to NFPA 805.

The Flowserve NX shaft sealing system design consists of three mechanical face-type sealing stages arranged for assembly as a single piece cartridge unit for installation in the RCP. During normal operation, each seal stage is subjected to a differential pressure of approximately one-third of reactor coolant system (RCS) pressure. Each of the three individual sealing stages is designed to withstand full RCS pressure indefinitely with the RCP idle, and for a limited period of time with the pump running at a nominal speed. Additionally, normal and maximum seal leakage rates are lower than those of the existing seal, thereby reducing charging flow from the Chemical and Volume Control System (CVCS) and reducing RCS inventory loss during plant transients. The Flowserve NX seal package also includes an abeyance, or shutdown seal that activates after failure of all three stages. Activation of the abeyance seal is not credited for design basis events, but is credited for beyond design basis events to limit RCS inventory losses.

10 CFR 50.59 Evaluation:

This change does not require prior NRC approval in accordance with 10 CFR 50.59(c)(1). The performance requirements of the new Flowserve NX seals were reviewed against the existing Areva/Westinghouse seal designs and demonstrated that the replacement seals would provide improved performance characteristics under normal and transient conditions.

DESIGN CHANGE PACKAGE EC 289127
Revision 0

UNIT: 4
TEMPORARY LOWERING OF SFP WATER TO SUPPORT MAINTENANCE REPLACEMENT OF THE PROCESS DIAPHRAGM ON 4-798B UNDER WO40198323-01

SUMMARY:

This temporary modification was developed to support replacement of the process diaphragm on 4-798B (Spent Fuel Pool (SFP) Demin. Return Valve to Spent Fuel Pool). The clearance for this activity requires lowering the Unit 4 SFP level below the ½" diameter hole in the discharge pipe that is submerging in the pool so that the line can be drained without siphoning water from the pool.

Temporarily decreasing the SFP water level below the Technical Specification limit of 56' – 10" to support maintenance to the SFP Filter valve requires a 10CFR50.59 evaluation as well as a risk evaluation per 10 CFR 50.65.

10 CFR 50.59 Evaluation:

Per Technical Specifications Section 3/4.9.11, the water level shall be maintained greater than or equal to elevation 56' – 10" in the spent fuel storage pool. Action statement b) includes the following, "The requirements of this specification may be suspended for more than 4 hours to perform maintenance provided a 10 CFR 50.59 evaluation is prepared prior to suspension of the above requirement and all movement of fuel assemblies and crane operation with loads in the fuel storage areas are suspended. If the level is not restored within 7 days, the NRC shall be notified within the next 24 hours." The 10 CFR 50.59 evaluation of this activity concludes that the temporary lowering of SFP water level in accordance with this evaluation is acceptable and the proposed activity does not require prior NRC approval, or require a change to plant Technical Specifications.

SECTION 2

10 CFR 50.59 EVALUATIONS

SUMMARY FOR SECTION 2: 10 CFR 50.59 EVALUATIONS

10 CFR 50.59(d)(2) requires that each licensee submit a periodic report containing a brief description of any changes, tests, and experiments made or conducted at their facility under the criteria of 10 CFR 50.59(c)(2). This report is also required to include a summary of the evaluation of each change, test, or experiment. Florida Power & Light Company is committed to submitting this report for the Turkey Point facility six months after each Unit 4 refueling outage.

This report contained herein covers the period between April 29, 2016 and October 31, 2017. During this period, the following engineering evaluations were approved under the criteria of 10 CFR 50.59(c)(2).

ENGINEERING EVALUATION
JPN-PTN-SEMS-96-003 REV. 9
(EC 289227 Revision 1)

UNIT: 4
10CFR50.59 EVALUATION FOR UNIT 4 STEAM GENERATORS' SECONDARY SIDE FOREIGN OBJECTS

SUMMARY:

Foreign objects have previously been identified within the secondary side of all of the Unit 4 Steam Generators. Evaluation JPN-PTN-SEMS-96-003 address the foreign objects which are not retrievable (or have not been retrieved) and potentially remain within the Steam Generators. Prior Evaluations have addressed the acceptability of continued Unit 4 operation with foreign objects remaining in the Steam Generators and associated systems. Revision 9 incorporates the results from the 2009 Unit 4 Cycle 25 refueling outage inspections. This included secondary side FOSAR (Foreign Object Search and Retrieval) inspections and full length ECT examination of 100% of active tubes. Both of the objects found during PT4-25 (Plant Turkey Point, Unit 4 Cycle 25) were assessed in accordance with the methodology provided in WCAP-14258. The acceptance standard for the wear time was based on the time to the next 100% ECT, at which point the minimum wall thickness of the subject tubes would be re-evaluated. In both cases, the identified objects did not yield a minimum wear time that would challenge the integrity of the affected tubes. Revision 9 also captures the results of the 2012 Unit 4 Cycle 27 refueling outage inspections. The locations of several of the tracked items were confirmed and some items were removed: no new objects were left in the Steam Generators. Additionally, there was no damage identified during the visual inspection or the Eddy Current Testing (ECT) for the tubes of the affected areas. The updates required for the PT4-27 refueling outage are administrative only and do not include alterations to any previously completed wear rate calculations. Revision 9 also captures the results of the October 2014 Unit 4 Cycle 28 (EOC 27) refueling outage inspections and the March 2016 Unit 4 Cycle 29 (EOC 28) inspections. This Revision 9 provides the evaluation and documentation to support safe operation of the Unit 4 Steam Generators with foreign objects present in the secondary side until PT4-31 (Plant Turkey Point, Unit 4 Cycle 31).

10 CFR 50.59 Evaluation:

The 10 CFR 50.59 Evaluation for Revision 9 of JPN-PTN-SEMS-96-003 concludes that the presence of secondary side foreign objects does not result in more than a minimal impact to any safety related design function, nor does it require a change to the Technical Specifications. It was determined that this activity did not require prior NRC approval. Continued operation of the Unit 4 Steam Generators within the restriction of the wear time calculations and TS surveillance requirements with the foreign objects present in the secondary side was determined to be acceptable under the existing design, analysis and licensing requirements. The Unit 4 Steam Generators shall receive 100% ECT inspection prior to exceeding any wear time calculation.

UFSAR CHANGE REQUEST
REACTOR COOLANT SYSTEM DEBRIS
(EC 290056 Revision 1)

UNIT: 4
10CFR50.59 EVALUATION FOR UNIT 4 REACTOR COOLANT SYSTEM DEBRIS

SUMMARY:

EC-UCR 290056 (AR 2229699 and 2230537) describe two different pieces of debris—cap screw and c-clip—remaining in the reactor vessel. These items were lost in the reactor coolant system (RCS) during refueling activities and were evaluated for their potential impacts to equipment within the RCS. The 50.59 screening determined only the c-clip warranted further evaluation because of the increased potential for a cladding failure. The cap screw is not included in this evaluation because it cannot damage fuel cladding.

10 CFR 50.59 Evaluation:

As stated in the UFSAR, the reactor design considered the potential for operating with cladding damage up to 1% of the fuel rods (320 rods) in the core. Fuel cladding defects within plant Technical Specifications limits during any mode of operation is a condition I event (ANSI/ANS 51.1-1973). The c-clip has the potential to damage up to four (4) fuel rods. This value is significantly less than 1% cladding failure which is the bases of Technical Specification 3.4.8. Therefore the potential fuel failure caused by the c-clip will not change the frequency classification and thus the proposed activity will not have a more than minimal increase in the frequency of occurrence of an accident previously evaluated in the UFSAR. Failure of up to 1% of fuel cladding is within the plant's operational design bases (dose consequences, RCS cleanup systems, equipment qualifications, and ALARA personnel shielding). Fuel failure from debris has been considered in the design of the RCS. It has been shown that the c-clip cannot fail more than 1% of the fuel cladding precluding the possibility of increasing the likelihood of a fuel failure malfunction. Continued compliance is demonstrated because cladding failure will not reach this threshold to create an increase in the likelihood of occurrence of a malfunction. All UFSAR Chapter 14 radiological dose consequence analysis includes 1% cladding defects (320 rods) as the initial condition. The c-clip will not damage more than 4 out of 32028 fuel rods and is within the allowance for possible fuel failures. There are no changes to dose consequence analysis results. Since no new failure modes are created by the proposed activity, it is concluded that there is no possibility that an accident may be created that is different from any already evaluated in the UFSAR.

No analysis must be changed to accommodate the c-clip. There is no impact to any radiological, thermal hydraulic, nuclear, or mechanical analysis of the fuel cladding or safety analysis; therefore, this change does not result in a departure from a design basis or safety analysis method. Reactor Coolant System, Specific Activity (TS 3.4.8) is limited to 0.25 μCi dose equivalent I-131 and 447.7 μCi dose equivalent Xe-133. This limit is based on 1% cladding defects. DNB parameters (TS 2.1.1 & 3.2.5) are not affected.

The 10 CFR 50.59 Evaluation concludes that this activity did not require prior NRC approval.

ENGINEERING EVALUATION
LOWERING OF SPENT FUEL POOL WATER
(EC 286596 Revision 0)

UNIT: 3
10 CFR 50.59 EVALUATION FOR TEMPORARY LOWERING OF SPENT FUEL POOL WATER TO SUPPORT MAINTENANCE ON 3-798B

SUMMARY:

The subject activity for this evaluation involved work to replace the process diaphragm on 3-798B, SFP Demin. Return Valve To Spent Fuel Pit. The clearance required lowering the Unit 3 SFP level below the ½" diameter hole in the discharge pipe that is submerged in the pool so that the line could be drained without siphoning water from the pool. Lowering the SFP water level was controlled by a one-time Temporary Change (TC) to procedure 3-NOP-033 under AR/PCR 02041836. The purpose of this EC/DCR was for the transmittal of the 10 CFR 50.59 evaluation.

Technical Specification 3/4.9.11 states the water level shall be maintained greater than or equal to elevation 56' – 10" in the spent fuel storage pool whenever irradiated fuel assemblies are in the storage pool. The requirements of this specification may be suspended for more than 4 hours to perform maintenance, provided a 10 CFR 50.59 evaluation is prepared prior to suspension of the above requirement and all movement of fuel assemblies and crane operation with loads in the fuel storage areas are suspended. The 10 CFR50.59 evaluation for this activity was required because the activity exceeded a 4 hour duration.

10 CFR 50.59 Evaluation:

Technical Specification 3/4.9.11 allows for the temporary reduction of SFP water level for more than four (4) hours to perform maintenance related activities if a 10 CFR 50.59 evaluation is prepared in advance. This specification also requires suspension of all movement of fuel assemblies and crane operations in the fuel storage area. If level is not restored within 7 days, the NRC shall be notified within the next 24 hours. SFP level for this activity was scheduled to be restored within 2 days.

The evaluation concluded that the temporary lowering of SFP water level was acceptable and the proposed activity did not require prior NRC approval, or require a change to plant Technical Specifications.

UFSAR CHANGE REQUEST
EXTENSION OF TURBINE VALVE TEST FREQUENCY
(EC 284975 Revision 0)

UNIT: 3 & 4
UFSAR CHANGE TO ALLOW EXTENSION OF THE SIX MONTH TURBINE VALVE TEST FREQUENCY TO TWELVE MONTHS

SUMMARY:

The turbine valve test is scheduled every six months to ensure that the valves remain reliable to close when demanded to prevent a turbine over speed and blade failure. Turkey Point has periodically extended the periodicity of this test beyond 6 months with no reduction in reliability. The proposed change extends the test frequency to 12 months, and updates the UFSAR accordingly. The change in frequency remains within NRC acceptance criteria and reduces the number of load reductions on both units during the operating cycle

AR 02055068-04 provided a risk assessment for a potential increase in the frequency of performing the turbine valve test from once per 6 months to once per 12 months. The risk assessment identifies WCAP 16054-P, "Probabilistic Analysis of Reduction in Turbine Missiles", dated April, 2003 as providing the bounding analysis. The WCAP analysis states that for an 18-month refueling cycle and 18-month stop valve disc surveillance interval, the frequency is 2.9E-6 with 6-month intervals and 4.26E-06 with 12-month intervals. This remains below the NRC acceptance criteria of 1 E-5.

10 CFR 50.59 Evaluation:

The turbine stop and control valve test is currently scheduled every six months to ensure that the valves remain reliable to close when demanded to prevent a turbine over speed and blade failure (Reference UFSAR Appendix 5E). The proposed change extends the test frequency to 12 months and updates the UFSAR accordingly. The 10 CFR 50.59 evaluation discussed the increase in the frequency of accidents previously evaluated in the UFSAR and concluded that this change does not result in more than a minimal increase in the frequency of occurrence of a turbine missile. The risk assessment performed for this activity identifies WCAP 16054-P, "Probabilistic Analysis of Reduction in Turbine Missiles", dated April, 2003 as providing the bounding analysis (Reference UFSAR Appendix SE, Reference SE-4). The WCAP analysis states that for an 18-month refueling cycle and 18-month stop valve disc surveillance interval, the frequency of occurrence of a turbine missile is 2.9E-6 with 6-month valve test intervals and 4.26E-06 with 12-month valve test intervals. The 10 CFR 50.59 evaluation concluded that the likelihood of a malfunction is not increased by a factor of 2 or more. Therefore this activity does not result in more than a minimal increase in the likelihood of occurrence of a malfunction previously evaluated in the UFSAR.

Based on the responses to the eight criteria of 10 CFR 50.59, the evaluation concluded that a license amendment is not required prior to implementation of this activity. This activity can be implemented without prior NRC approval.

Section 3

Technical Specification Bases Changes

SUMMARY FOR SECTION 3: TECHNICAL SPECIFICATION BASES CONTROL PROGRAM

Amendments 222 and 217 to the Turkey Point Units 3 and 4 operating licenses, respectively, added Technical Specification 6.8.4.i, Technical Specifications Bases Control Program. Technical Specification (TS) 6.8.4.i.d requires changes to TS Bases that do not require prior NRC approval be submitted to the NRC "… on a frequency consistent with 10 CFR 50.71(e)." The report of changes made pursuant to 10 CFR 50.59 is also submitted consistent with 10 CFR 50.71(e) (the FSAR update). Therefore, changes made to the TS Bases are being submitted with this report and are contained in procedure 0-ADM-536, Technical Specification Bases Control Program. Attachments 1 (index) and 2 (TS Bases) of procedure 0-ADM-536 are provided in Attachment 2 of this letter. A summary of TS Bases changes made since the previous update follows:

0-ADM-536 TS Bases Changes

PCR (Procedure Change Request) 2140986

Sections 2.2.1 and 3/4.3.1 & 3/4.3.2 were revised to clarify that a corrective action program evaluation does not need to be completed prior to returning an out-of-tolerance instrument channel to service during a surveillance test if it can be recalibrated to within the as-left tolerance. In this case, the functional verification is performed in the field during the surveillance test.

PCR 2169786

Revised Section 3/4.5.2 - ECCS SUBSYSTEMS - T_{avg} GREATER THAN OR EQUAL TO 350ºF to add an Interim Compensatory Measure for missing ACTION pertaining to the parallel injection flow paths for Safety Injection (MOV-*-843A and B) and Residual Heat Removal (MOV-*-744A and B).

PCR 2187079

Section 3/4.7.6, Snubbers, was revised to conform with the changes approved by License Amendments 272 and 267 that added the Snubber Testing Program.

PCR 2159892

Section 3/4.7.1.2, Auxiliary Feedwater System, was revised to conform with the requirements for steam supply flowpaths as approved by License Amendments 273 and 268.

PCR 2203165

Section 3/4.0, was revised to reflect a change to Specification 4.0.5 and related conforming changes to implement TSTF-545 as authorized by License Amendments 274 and 269. The use of ASME OM Code Case OMN-20 was authorized for the Inservice Testing Program.

PCR 2190183

Section 3/4.8, Electrical Power Systems, was revised to provide further information on the application of Technical Specification 3.8.1.1, ACTIONs 'a' and 'c'.

PCR 2195391

Section 3/4.3.1 & 3/4.3.2, Reactor Trip System and Engineered Safety Features Actuation System Instrumentation, was revised to provide detail regarding a Mode 3 entry exception for performance of certain instrumentation surveillances allowed by Note 3 to Technical Specification Table 4.3-2.

PCR 2169473

Section 3/4.7.5, Control Room Emergency Ventilation System was revised as a result of License Amendments 275 and 270.

PCR 2234452

Section 3/4.3.3.3, Accident Monitoring Instrumentation, was revised to reflect the changes to TS 3/4.3.3.3.3, Tables 3.3-5 and 4.3-4, Accident Monitoring Instrumentation, approved by License Amendments 277 and 272. The amendments relocated the TSs for high-range noble gas effluent monitors to the Offsite Dose Calculation Manual.

PCR 2229788

Section 3/4.3.1 & 3/4.3.2, Reactor Trip System and Engineered Safety Features Actuation System Instrumentation, was revised to change Action 23 required actions for Auxiliary Feedwater System (AFW) Functional Unit (FU) 6(d), Bus Stripping, and AFW FU 6(e), Trip of All Main Feedwater Pump Breakers, as allowed by License Amendments 276 and 271.

Attachment 2

Turkey Point Nuclear Plant

Technical Specification Bases

Contained in Procedure 0-ADM-536,
Technical Specification Bases Control Program,
Attachments 1 and 2

(This coversheet plus 199 pages starting with 13 of 211)

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ATTACHMENT 2
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BASES FOR SECTION 2.0
SAFETY LIMITS
AND
LIMITING SAFETY SYSTEM SETTINGS

NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Section 2.0, but in accordance with 10 CFR 50.36 are **NOT** part of the Technical Specifications.

2.1 Safety Limits

2.1.1 Reactor Core

The restrictions of this Safety Limit prevent overheating of the fuel and possible cladding perforation which would result in the release of fission products to the reactor coolant. 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.

Operation above the upper boundary of the nucleate boiling regime could result in excessive cladding temperatures because of the onset of Departure from Nucleate Boiling (DNB) and the resultant sharp reduction in heat transfer coefficient. DNB is **NOT** a directly measurable parameter during operation; therefore, THERMAL POWER and reactor coolant temperature and pressure have been related to DNB. This relationship has been developed to predict the DNB flux and the location of DNB for axially uniform and non-uniform heat flux distributions. The local DNB heat flux ratio (DNBR) is defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux and is indicative of the margin to DNB.

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2.1.1 (Continued)

The DNB design basis is as follows: There must be at least a 95 percent probability with 95 percent confidence that the minimum DNBR of the limiting rod during Condition I and II events is greater than or equal to the DNBR limit of the DNB correlation being used. The correlation DNBR limit is established based on the entire applicable experimental data set such that there is a 95 percent probability with 95 percent confidence that DNB will **NOT** occur when the minimum DNBR is at the DNBR limit.

The curves (formerly TS Figure 2.1-1) provided in the COLR show the location of points of THERMAL POWER, Reactor Coolant System pressure and average temperature for which the minimum DNBR is **NO** less than the design DNBR value, or the average enthalpy at the vessel exit is equal to the enthalpy of saturated liquid.

In addition, fuel centerline temperature is required to stay below the melting temperature. Consistent with these design basis requirements, a DNB correlation and peak fuel centerline temperature limits are provided as Safety Limits in this Specification. The DNB correlation and parameter value of WRB 1 and 1.17, respectively, are applicable to the pre-Extended Power Uprate (EPU) and EPU operating cycles which contain residual 15x15 DRFA fuel from previous pre-uprate cycles and which contain 15x15 Upgrade fuel at the EPU conditions. The peak centerline temperature limit of less than 5080 ºF, decreasing by 58 ºF per 10,000 MWD/MTU of burnup, is the standard value used for Westinghouse fuel. The automatic enforcement of these Reactor Core Safety Limits is provided by the proper functioning of the reactor protection system and the steam generator safety valves.

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2.1.1 (Continued)

The curves provided in the COLR are based on an enthalpy hot channel factor, $F^N_{\Delta H}$, and a reference cosine with a peak of 1.78 for axial power shape. An allowance is included for an increase in $F^N_{\Delta H}$ at reduced power based on the expression:

$$F^N_{\Delta H} \leq F^{RTP}_{\Delta H}[1+ PF_{\Delta H} (1-P)]$$

Where P is the fraction of RATED THERMAL POWER

$F^{RTP}_{\Delta H}$ = $F_{\Delta H}$ limit at RATED THERMAL POWER as specified in the CORE OPERATING LIMITS REPORT

$PF_{\Delta H}$ = Power Factor multiplier for $F_{\Delta H}$ as specified in the CORE OPERATING LIMITS REPORT

These limiting heat flux conditions are higher than those calculated for the range of all control rods fully withdrawn to the maximum allowable control rod insertion limit assuming the axial power imbalance is within the limits of the f (ΔT) function of the Overtemperature trip. When the axial power imbalance is **NOT** within the tolerance, the axial power imbalance effect on the Overtemperature ΔT trips will reduce the setpoints to provide protection consistent with core Safety Limits.

Fuel rod bowing reduces the values of DNB ratio (DNBR). The penalties are calculated pursuant to Fuel Rod Bow Evaluation, WCAP-8691-P-A Revision 1 (Proprietary) and WCAP-8692 Revision 1 (Non-Proprietary). The restrictions of the Core Thermal Hydraulic Safety Limits assure that an amount of DNBR margin greater than or equal to the above penalties is retained to offset the rod bow DNBR penalty.

Former TS Figure 2.1-1 titled Reactor Core Safety Limit – Three Loops in Operation has been relocated to the COLR and replaced with the WRB-1 DNB correlation design basis limit and the peak fuel centerline temperature design basis limit per Amendments 247 and 243.

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2.1.2 Reactor Coolant System Pressure

The restriction of this Safety Limit protects the integrity of the Reactor Coolant System (RCS) from overpressurization and thereby prevents the release of radionuclides contained in the reactor coolant from reaching the containment atmosphere.

The reactor vessel and pressurizer are designed to Section III of the ASME Code for Nuclear Power Plants which permits a maximum transient pressure of 110% (2735 psig) of design pressure. The RCS piping, valves, and fittings are designed to ANSI B31.1, which permits a maximum transient pressure of 120% of design pressure of 2485 psig. The Safety Limit of 2735 psig is therefore more conservative than the ANSI B31.1 design criteria and consistent with associated ASME Code requirements.

The entire RCS is hydro tested at 125% (3107 psig) of design pressure to demonstrate integrity prior to initial operation.

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2.2 Limiting Safety System Settings (LSSS)

2.2.1 Reactor Trip System Instrumentation Setpoints

The Trip Setpoints (or Nominal Trip Setpoints (NTS)) specified in Table 2.2-1 are the nominal values at which the reactor trips are set. The Trip Setpoints have been selected to ensure that the core and Reactor Coolant System are prevented from exceeding their safety limits during normal operation and design basis anticipated operational occurrences and to assist the Engineered Safety Features Actuation System in mitigating the consequences of accidents. The setpoint for a Reactor Trip System (RTS) or interlock function is considered to be adjusted consistent with the Trip Setpoint when the as measured setpoint is within the band allowed for calibration accuracy.

To accommodate instrument drift that may occur between operational tests and the accuracy to which setpoints can be measured and calibrated, allowances are provided for in the Trip Setpoint and Allowable Values in accordance with the setpoint methodology described in WCAPs 17070-P (for Functional Units 2a, 5, 6, 10, 11, 12, and 15a) and 12745. Surveillance criteria have been determined and are controlled in plant procedures and in design documents. The surveillance criteria ensure that instruments which are **NOT** operating within the assumptions of the setpoint calculations are identified. An instrument channel is considered OPERABLE when the Trip Setpoint is within the Allowable Value and the channel is capable of being calibrated in accordance with plant procedures to within the As Left tolerance. If the As Found setpoint is outside the As Found tolerance, the occurrence will be entered into the Corrective Action Program (CAP) and the channel will be evaluated to verify that it is functioning as required before returning the channel to service. The CAP evaluation does not need to be completed prior to returning the channel to service if it can be recalibrated to within the as-left tolerance. In this case, the functional verification is performed in the field during the surveillance test. Sensor and other instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes.

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2.2.1 (Continued)

There is a small statistical probability that a properly functioning device will drift beyond determined surveillance criteria. Infrequent drift outside the surveillance criteria are expected. Excessive rack or sensor drift that is more than occasional may be indicative of more serious problems and should warrant further investigations.

The Trip Setpoints used in the bistables for Functional Units 2a, 5, 6, 10, 11, 12, and 15a are based on the analytical limits stated in WCAP-17070-P and UFSAR Section 7.2. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those RTS channels that must function in harsh environments as defined by 10 CFR 50.49, the Trip Setpoints are conservative with respect to the analytical limits. A detailed description of the methodology used to determine the Trip Setpoint, Allowable Value, As Left tolerance, and As Found tolerance including their explicit uncertainties, is provided in WCAP-17070-P and UFSAR Section 7.2 which incorporates all of the known uncertainties applicable to these Functional Units. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint and corresponding Allowable Value.

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2.2.1 (Continued)

The Trip Setpoint for Functional Units 2a, 5, 6, 10, 11, 12, and 15a is the value at which the bistable is set and is the expected value to be achieved during calibration. The Trip Setpoint value is the LSSS and ensures the safety analysis limits are met for the surveillance interval selected when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the As Left Trip Setpoint value is within the As Left tolerance band for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration accuracy). The Trip Setpoint value is therefore considered a "nominal" value (i.e., expressed as a value without inequalities) for the purposes of ANALOG/DIGITAL CHANNEL OPERATIONAL TEST (COT) and CHANNEL CALIBRATION. These Functional Units have been modified by two notes as identified in Table 4.3-1. Note (a) requires evaluation of channel performance for the condition where the As Found setting for the Trip Setpoint is outside of the As Found criterion. As stated above, these instances will be entered into the CAP and the channel will be evaluated to verify that it is functioning as required before returning the channel to service. Note (b) requires that the channel As Left setting must be within the As Left tolerance band. As noted above a channel is considered to be properly calibrated when the As Left Trip Setpoint value is within the As Left tolerance band for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration accuracy).

The various reactor trip circuits automatically open the Reactor Trip Breakers whenever a condition monitored by the RTS reaches a preset or calculated level. In addition to redundant channels and trains, the design approach provides a RTS which monitors numerous system variables; therefore, providing functional diversity. The functional capability at the specified trip setting is required for those anticipatory or diverse reactor trips for which **NO** direct credit was assumed in the safety analysis to enhance the overall reliability of the RTS. The RTS initiates a Turbine trip signal whenever a reactor trip is initiated. This prevents the reactivity insertion that would otherwise result from excessive Reactor Coolant System cooldown and thus avoids unnecessary actuation of the Engineered Safety Features Actuation System.

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2.2.1 (Continued)

Manual Reactor Trip

The Reactor Trip System includes manual reactor trip capability.

Power Range, Neutron Flux

In each of the Power Range Neutron Flux channels there are two independent bistables, each with its own trip setting used for a High and Low Range trip setting. The Low Setpoint trip provides protection during subcritical and low power operations to mitigate the consequences of a power excursion beginning from low power, and the High Setpoint trip provides protection during power operations for all power levels to mitigate the consequences of a reactivity excursion which may be too rapid for the temperature and pressure protective trips.

The Low Setpoint trip may be manually blocked above P-10 (a power level of approximately 10% of RATED THERMAL POWER) and is automatically reinstated below the P-10 Setpoint.

Intermediate and Source Range, Neutron Flux

The Intermediate and Source Range, Neutron Flux Trips provide core protection during reactor startup to mitigate the consequences of an uncontrolled rod cluster control assembly bank withdrawal from a subcritical condition. These trips provide redundant protection to the Low Setpoint trip of the Power Range, Neutron Flux channels. The Source Range channels will initiate a Reactor Trip at about 10^5 counts per second unless manually blocked when P-6 becomes active. The Intermediate Range channels will initiate a Reactor Trip at a current level equivalent to approximately 25% of RATED THERMAL POWER unless manually blocked when P-10 becomes active. **NO** credit is taken for operation of the trips associated with either the Intermediate or Source Range Channels in the accident analyses; however, their functional capability at the specified trip settings is required by this specification to enhance the overall reliability of the Reactor Protection System.

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2.2.1 (Continued)

Overtemperature ΔT

The Overtemperature ΔT trip provides core protection to prevent DNB for all combinations of pressure, power, coolant temperature, and axial power distribution, provided that the transient is slow with respect to piping transit delays from the core to the temperature detectors and pressure is within the range between the Pressurizer High and Low Pressure Trips. The setpoint is automatically varied with: (1) Coolant temperature to correct for temperature induced changes in density and heat capacity of water and includes dynamic compensation for piping delays from the core to the loop temperature detectors, (2) Pressurizer pressure, and (3) Axial power distribution. With normal axial power distribution, this Reactor Trip limit is always below the Core Safety Limit as shown in the COLR. If axial peaks are greater than design, as indicated by the difference between top and bottom power range nuclear detectors, the Reactor Trip is automatically reduced according to the notations in Table 2.2-1. Note that selected parameters for OTΔT including K values, τ time constants, T′, P′ and the breakpoint and slope values for the f1(ΔI) function have been moved to the COLR.

Overpower ΔT

The Overpower ΔT trip prevents power density anywhere in the core from exceeding 118% of the design power density. This provides assurance of fuel integrity (e.g., **NO** fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions, limits the required range for Overtemperature ΔT Trip, and provides a backup to the High Neutron Flux Trip. The setpoint is automatically varied with: (1) Coolant temperature to correct for temperature induced changes in density and heat capacity of water, and (2) Rate of change of temperature for dynamic compensation for piping delays from the core to the loop temperature detectors to ensure that the allowable heat generation rate (kW/ft) is **NOT** exceeded. Note that selected parameters for OPΔT including K values, τ_7, T″ and f_2(ΔI) function have been moved to the COLR.

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2.2.1 (Continued)

Pressurizer Pressure

In each of the Pressurizer Pressure Channels, there are two independent bistables, each with its own trip setting to provide for a High and Low Pressure Trip thus limiting the pressure range in which reactor operation is permitted. The Low Setpoint Trip protects against low pressure which could lead to DNB by tripping the reactor in the event of a loss of reactor coolant pressure.

On decreasing power the Low Setpoint Trip is automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with Turbine Inlet Pressure at approximately 10% of full power equivalent) and on increasing power, automatically reinstated by P-7.

The High Setpoint Trip functions in conjunction with the Pressurizer Safety Valves to protect the Reactor Coolant System against system overpressure.

Pressurizer Water Level

The Pressurizer Water Level-High Trip is provided to prevent water relief through the Pressurizer Safety Valves. On decreasing power the Pressurizer High Water Level Trip is automatically blocked by P7 (a power level of approximately 10% of RATED THERMAL POWER with a Turbine Inlet Pressure at approximately 10% of full power equivalent) and on increasing power, automatically reinstated by P-7.

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2.2.1 (Continued)

Reactor Coolant Flow

The Reactor Coolant Flow-Low Trip provides core protection to prevent DNB by mitigating the consequences of a loss of flow resulting from the loss of one or more Reactor Coolant Pumps.

On increasing power above P-7 (a power level of approximately 10% of RATED THERMAL POWER or a Turbine Inlet Pressure at approximately 10% of full power equivalent), an automatic Reactor Trip will occur if the flow in more than one loop drops below 90% of loop design flow. Above P-8 (a power level of approximately 45% of RATED THERMAL POWER) an automatic Reactor Trip will occur if the flow in any single loop drops below 90% of design loop flow. Conversely, on decreasing power between P8 and the P-7 an automatic Reactor Trip will occur on low reactor coolant flow in more than one loop and below P-7 the trip function is automatically blocked.

Steam Generator Water Level

The Steam Generator Water Level Low-Low Trip protects the reactor from loss of heat sink in the event of a sustained steam/feedwater flow mismatch resulting from loss of normal feedwater. The specified setpoint provides allowances for starting delays of the Auxiliary Feedwater System.

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2.2.1 (Continued)

Steam/Feedwater Flow Mismatch and Low Steam Generator Water Level

The Steam/Feedwater Flow Mismatch in coincidence with a Steam Generator Water Level Low Trip is **NOT** used in the transient and accident analyses but is included in Table 2.2-1 to ensure the functional capability of the specified trip settings and thereby enhance the overall reliability of the Reactor Trip System. This trip is redundant to the Steam Generator Water Level Low-Low trip. The Steam/Feedwater Flow Mismatch portion of this trip is activated when the steam flow exceeds the feedwater flow by 20% rated steam flow. The Steam Generator Water Level-Low portion of the trip is activated when the water level drops below 16%, as indicated by the narrow range instrument. These trip values include sufficient allowance in excess of normal operating values to preclude spurious trips but will initiate a Reactor trip before the steam generators are dry. Therefore, the required capacity and starting time requirements of the Auxiliary Feedwater Pumps are reduced and the resulting thermal transient on the Reactor Coolant System and Steam Generators is minimized.

Undervoltage - 4.16 kV Bus A and B Trips

The 4.16 kV Bus A and B Undervoltage trips provide core protection against DNB as a result of complete loss of forced coolant flow. The specified setpoint assures a Reactor Trip signal is generated before the Low Flow Trip Setpoint is reached. Time delays are incorporated in the Undervoltage Trips to prevent spurious reactor trips from momentary electrical power transients. The delay is set so that the time required for a signal to reach the Reactor Trip Breakers following the trip of at least one undervoltage relay in both of the associated Units 4.16 kV busses shall **NOT** exceed 1.5 seconds. On decreasing power the Undervoltage Bus Trips are automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with a Turbine Inlet Pressure at approximately 10% of full power equivalent) and on increasing power, reinstated automatically by P-7.

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2.2.1 (Continued)

Turbine Trip

A Turbine Trip initiates a Reactor Trip. On decreasing power, the Reactor Trip from the Turbine Trip is automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with a Turbine Inlet Pressure at approximately 10% of full power equivalent) and on increasing power, reinstated automatically by P-7.

The Reactor Trip from Turbine Trip function anticipates the loss of secondary heat removal capability from a power level above the P-7 setpoint. Below the P-7 setpoint this action will **NOT** actuate a reactor trip. The Turbine Trip Function is **NOT** required to be OPERABLE below P-7 because load rejection can be accommodated by the steam dump system or Steam Generator Atmospheric Dump Valves. 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.

Tripping the reactor in anticipation of a loss of secondary heat removal capability acts to minimize the pressure and temperature transients on the reactor. Two separate mechanisms are designed to detect a turbine trip, low EHC oil pressure or Stop Valve closure. Three pressure switches monitor the control oil pressure in the Emergency Trip Header Oil in the EHC 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 Turbine Trip-Turbine Stop Valve Closure trip function is diverse to the Turbine Emergency Trip Header 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 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 reactor trip from Turbine trip is **NOT** credited in the accident analysis for core protection.

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2.2.1 (Continued)

The setpoint is considered to be adjusted consistent with the Nominal Trip Setpoint (NTS) when the as-measured setpoint is within the band allowed for calibration accuracy. Notes (a) and (b) are applied to the Turbine Emergency Trip Header Pressure trip function in Table 2.2-1, Reactor Trip Setpoints and in Table 4.3-1, Reactor Trip System Instrumentation Surveillance Requirements. Note (a) requires that if the As Found trip setpoint is outside predefined limits based on actual expected errors between calibrations then corrective action is required. If the As Found trip setpoints are outside the Allowable Value, then the instrument channel is inoperable. Note (b) requires that the trip setpoint is considered to be properly adjusted when the As Left NTS value is within the predefined As Left tolerance for CHANNEL CALIBRATION. The As Found and As Left values shall be determined using a methodology consistent with WCAP-17070

Safety Injection Input from ESF

If a Reactor Trip has **NOT** already been generated by the Reactor Trip System instrumentation, the ESF automatic actuation logic channels will initiate a Reactor Trip upon any signal which initiates a Safety Injection. The ESF instrumentation channels which initiate a Safety Injection signal are shown in Table 3.3-3.

Reactor Coolant Pump Breaker Position Trip

The Reactor Coolant Pump Breaker Position Trips are anticipatory trips which provide reactor core protection against DNB. The open/close position trips assure a Reactor Trip signal is generated before the low flow trip setpoint is reached. Their functional capability at the open/close position settings is required to enhance the overall reliability of the Reactor Protection System. Above P-7 (a power level of approximately 10% of RATED THERMAL POWER or a Turbine Inlet Pressure at approximately 10% of full power equivalent) an automatic Reactor Trip will occur if more than one Reactor Coolant Pump breaker is opened. Above P-8 (a power level of approximately 45% of RATED THERMAL POWER) an automatic Reactor Trip will occur if one Reactor Coolant Pump breaker is opened. On decreasing power between P-8 and P-7, an automatic Reactor Trip will occur if more than one Reactor Coolant Pump breaker is opened and below P-7 the trip function is automatically blocked.

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2.2.1 (Continued)

Underfrequency sensors are also installed on the 4.16 kV busses to detect underfrequency and initiate breaker trip on underfrequency. The Underfrequency Trip setpoints preserve the coast down energy of the Reactor Coolant Pumps, in case of a grid frequency decrease so DNB does **NOT** occur.

Reactor Trip System Interlocks

The Reactor Trip System interlocks perform the following functions:

P-6 On increasing power, P-6 allows the manual block of the Source Range Trip (i.e., prevents premature block of Source Range Trip) and deenergizes the high voltage to the detectors. On decreasing power, Source Range Level Trips are automatically reactivated and high voltage restored.

P-7 On increasing power, P-7 automatically enables Reactor Trips on low flow in more than one Reactor Coolant Loop, more than one Reactor Coolant Pump breaker open, Reactor Coolant Pump bus undervoltage and underfrequency, Turbine Trip, Pressurizer Low Pressure and Pressurizer High Level. On decreasing power, the above listed trips are automatically blocked.

P-8 On increasing power, P-8 automatically enables Reactor Trips on low flow in one or more Reactor Coolant Loops, and one or more Reactor Coolant Pump breakers open. On decreasing power, the P-8 interlock automatically blocks the trip on low flow in one coolant loop or one coolant pump breaker open.

P-10 On increasing power, P-10 allows the manual block of the Intermediate Range Trip and the Low Setpoint Power Range trip; and automatically blocks the Source Range Trip and deenergizes the Source Range high voltage power. On decreasing power, the Intermediate Range Trip and the Low Setpoint Power Range Trip are automatically reactivated. P-10 also provides input to P-7. The trip setpoint on increasing power shall be $\geq$ 10% and the reset point shall be less than or equal to 10%.

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BASES FOR SECTIONS 3.0 AND 4.0
LIMITING CONDITIONS FOR OPERATION
AND
SURVEILLANCE REQUIREMENTS

NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Sections 3.0 and 4.0, but in accordance with 10 CFR 50.36 are **NOT** part of the Technical Specifications.

3/4.0 Applicability

Limiting Conditions for Operation

Specifications 3.0.1 through 3.0.6 establish the general requirements applicable to Limiting Conditions for Operation. Limiting Conditions for Operation apply at all times including during transients and accidents, unless otherwise specified. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10 CFR 50.36(c)(2):

Limiting Conditions for Operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a Limiting Condition for Operation of a nuclear reactor is **NOT** met, the licensee shall shut down the reactor or follow any remedial action permitted by the Technical Specification until the condition can be met.

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL MODES or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are **NOT** met.

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3/4.0 (Continued)

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is **NOT** further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are **NOT** completed within the allowable outage time limits, a shutdown is required to place the facility in a MODE or condition in which the specification **NO** longer applies. It is **NOT** intended that the shutdown ACTION requirements be used as an operational convenience which permits (routine) voluntary removal of a systems or components from service in lieu of other alternatives that would **NOT** result in redundant systems or components being inoperable.

The specified time limits of the ACTION requirements are applicable from the point in time it is identified that a Limiting Condition for Operation is **NOT** met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of the ACTION requirements are applicable when this limit expires if the surveillance has **NOT** been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered a MODE in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are **NOT** met.

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3/4.0 (Continued)

Specification 3.0.2 establishes that noncompliance with a specification exists when the requirements of the Limiting Condition for Operation are **NOT** met and the associated ACTION requirements have **NOT** been implemented within the specified time interval. The purpose of this specification is to clarify that (1) Implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification, and (2) Completion of the remedial measures of the ACTION requirements is **NOT** required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is **NOT** met and the condition is **NOT** specifically addressed by the associated ACTION requirements. The purpose of this specification is to delineate the time limits for placing the unit in a safe shutdown MODE when plant operation cannot be maintained within the limits for safe operation defined by the Limiting Conditions for Operation and its ACTION requirements. It is **NOT** intended to be used as an operational convenience which 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. One hour is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This time permits the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. 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 cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

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3/4.0 (Continued)

If remedial measures permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time there was a failure to meet a Limiting Condition for Operation. Therefore, the shutdown may be terminated if the ACTION requirements have been met or the time limits of the ACTION requirements have **NOT** expired, thus providing an allowance for the completion of the required actions.

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in the COLD SHUTDOWN MODE when a shutdown is required during the POWER MODE of 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 of operation applies. However, if a lower MODE of operation is reached in less time than allowed, the total allowable time to reach COLD SHUTDOWN, or other applicable MODE, is **NOT** reduced. For example, if HOT STANDBY is reached in 2 hours, the time allowed to reach HOT SHUTDOWN is the next 11 hours because the total time to reach HOT SHUTDOWN is **NOT** reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is **NOT** incurred by having to reach a lower MODE of operation in less than the total time allowed.

The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into a MODE or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are **NOT** met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time limits of ACTION requirements for a higher MODE of operation may **NOT** be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is **NOT** met in a lower MODE of operation.

The shutdown requirements of Specification 3.0.3 do **NOT** apply in MODES 5 and 6, because the ACTION requirements of individual specifications define the remedial measures to be taken.

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3/4.0 (Continued)

Specification 3.0.4 establishes limitations on MODE changes when a Limiting Condition for Operation is **NOT** met. It precludes placing the facility in a higher MODE of operation when the requirements for a Limiting Condition for Operation are **NOT** met and continued noncompliance to these conditions would result in a shutdown to comply with the ACTION requirements if a change in MODES were permitted. The purpose of this specification is to ensure that facility operation is **NOT** initiated or that higher MODES of operation are **NOT** entered when corrective action is being taken to obtain compliance with a specification by restoring equipment to OPERABLE status or parameters to specified limits. Compliance with ACTION requirements that permit continued operation of the facility for an unlimited period of time provides an acceptable level of safety for continued operation without regard to the status of the plant before or after a MODE change. Therefore, in this case, entry into an OPERATIONAL MODE or other specified condition may be made in accordance with the provisions of the ACTION requirements. The provisions of this specification should **NOT**, however, be interpreted as endorsing the failure to exercise good practice in restoring systems or components to OPERABLE status before plant startup.

When a shutdown is required to comply with ACTION requirements, the provisions of Specification 3.0.4 do **NOT** apply because they would delay placing the facility in a lower MODE of operation.

Specification 3.0.5 delineates the applicability of each specification to Unit 3 operation.

Specification 3.0.6 establishes the allowance for restoring equipment to service under administrative controls when equipment has been removed from service or declared inoperable to comply with Technical Specification ACTION requirements. The sole purpose of this specification is to provide an exception to TS 3.0.1 and 3.0.2 (i.e., to **NOT** comply with the applicable required actions to allow the performance of required testing to demonstrate either:

- The OPERABILITY of the equipment being returned to service
- The OPERABILITY of other equipment.

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3/4.0 (Continued)

Administrative Controls, such as test procedures, ensure the time the equipment is returned to service in conflict with the ACTION requirements is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. LCO 3.0.6 does **NOT** provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that was closed to comply with TS action requirements. The valve must be reopened to perform the testing required to demonstrate OPERABILITY.

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 required testing on another channel in the other trip system.

A similar example of demonstrating OPERABILITY of the 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 required testing on another channel in the same trip system.

Temporarily returning inoperable equipment to service for the purpose of confirming OPERABILITY, places the plant in a condition which has been previously evaluated in the development of the current Technical Specifications and determined to be acceptable for short periods as prescribed by allowed outage times in ACTION requirements. Performance of the surveillance/testing is considered to be a confirmatory check of that capability which demonstrates that the equipment is indeed operable in most cases. For those times when equipment, which may be temporarily returned to service under administrative controls per LCO 3.0.6, is subsequently determined to remain inoperable, the Technical Specification ACTION requirements continue to apply until the equipment is determined OPERABLE.

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3/4.0 (Continued)

Surveillance Requirements

Specification 4.0.1 through 4.0.6 establishes the general requirements applicable to Surveillance Requirements. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations, 10 CFR 50.36(c)(3):

Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

Specifications 4.0.1 through 4.0.6 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated. Specification 4.0.2, and 4.0.3, apply to Section 6.8, Procedures and Programs, only when invoked by a Section 6.8 Specification.

Specification 4.0.1 establishes the requirement that surveillances must be performed during the OPERATIONAL MODES or other conditions for which the requirements of the Limiting Conditions for Operation apply unless otherwise stated in an individual Surveillance Requirement. The purpose of this specification is to ensure that surveillances are performed to verify the operational status of systems and components and that parameters are within specified limits to ensure safe operation of the facility when the plant is in a MODE or other specified condition for which the associated Limiting Conditions for Operation are applicable. Surveillance Requirements do **NOT** have to be performed when the facility is in an OPERATIONAL MODE for which the requirements of the associated Limiting Condition for operation do **NOT** apply unless otherwise specified. The Surveillance Requirements associated with a Special Test Exception are only applicable when the Special Test Exception is used as an allowable exception to the requirements of a specification.

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This requirement also establishes the failure to perform a Surveillance Requirement within the allowed surveillance interval, defined by the provisions of Specification 4.0.2, as a condition that constitutes a failure to meet the OPERABILITY requirements for a Limiting Condition for Operation. Surveillances may be performed by means of any series of sequential, overlapping, or total steps provided the entire Surveillance is performed within the specified Frequency. Additionally, the definitions related to instrument testing (e.g., CHANNEL CALIBRATION) specify that these tests are performed by means of any series of sequential, overlapping, or total steps. Under the provisions of this specification, systems and components are assumed to be OPERABLE when Surveillance Requirements have been satisfactorily performed within the specified time interval. However, nothing in this provision is to be construed as implying that systems or components are OPERABLE when they are found or known to be inoperable although still meeting the Surveillance Requirements.

Surveillance Requirements do **NOT** have to be performed on inoperable equipment because the ACTION requirements define the remedial measures that apply. However, the Surveillance Requirements have to be met to demonstrate that inoperable equipment has been restored to OPERABLE status.

Specification 4.0.2 establishes the conditions under which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may **NOT** be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. The limits of Specification 4.0.2 are based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. These provisions are sufficient to ensure that the reliability ensured through surveillance activities is **NOT** significantly degraded beyond that obtained from the specified surveillance interval.

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3/4.0 (Continued)

The exceptions to 4.0.2 are those surveillances for which the 25% extension of the interval does not apply. These exceptions are stated in the individual specification. The requirements of regulations take precedence over Technical Specifications. Examples of where Specification 4.0.2 does not apply are the Containment Leakage Rate Testing Program by 10 CFR 50, Appendix J, and the Inservice Testing of pumps and valves in accordance with applicable ASME OM Code, as required by 10 CFR 50.55a. These programs establish testing requirements and frequencies in accordance with the requirements of regulations. The TS cannot, in and of themselves, extend a test interval specified in the regulations directly or by reference.

When a Section 6.8 “Procedures and Programs,” specification states that the provisions of Specification 4.0.2 are applicable, a 25% extension of the testing interval, whether stated in the Specification or incorporated by reference, is permitted.

The NRC authorized Turkey Point to utilize an approved relief request which adopts ASME OM Code Case OMN-20 for the remainder of the fifth 10-Year Inservice Testing Interval (IST), or until Code Case OMN-20 is incorporated into the revision of Regulatory Guide 1.192, as referenced by a future revision of 10 CFR 50.55a, whichever occurs first.

For IST periods up to and including 2 years, Code Case OMN-20 provides all allowance to extend the IST periods by up to 25%. The period extension is to facilitate test scheduling and considers plant operating conditions that may not be suitable for performance of the required testing (e.g. performance of the test would cause an unacceptable increase in the plant risk profile due to transient conditions or other ongoing surveillance, test or maintenance activity). Period extensions are not intended to be used repeatedly merely as an operation convenience to extent test intervals beyond those specified. The test period extension and the statements regarding the appropriate use of the period extension are equivalent to the existing allowances in Specification 4.0.2 and the statements regarding their use in the TS Bases section for 4.0.2.

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For IST periods of greater than 2 years, OMN-20 allows extensions of up to 6 months. The ASME OM Committee determined that such an extension is appropriate. The 6-month extension will have a minimal impact on component reliability considering that most probable result of performing any in-service test is satisfactory verification of the test acceptance criteria. As such, pumps and valves continue to be adequately assessed for operation readiness when tested in accordance with the requirements specified in 10 CFR 50.55a(f) with the frequency extensions allowed by Code Case OMN-20.

Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance requirement 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 greater, applies from the point in time that it is discovered that the Surveillance has **NOT** been performed in accordance with Specification 4.0.2, 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 requirement 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 unit 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.

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When a Surveillance with a frequency based **NOT** on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading) is discovered to **NOT** have been performed when specified, Specification 4.0.3 allows for the full delay period of up to the specified frequency to perform the Surveillance. However, since there is **NOT** a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

Specification 4.0.3 provides a time limit for, and allowances for the performance of, a Surveillance that becomes applicable as a consequence of MODE changes imposed by required ACTIONs.

Programmatic test frequencies can not be extended in accordance with Specification 4.0.2, or delayed in accordance with Specification 4.0.3, unless specified. When a Section 6.8 “Procedures and Programs,” specification states that the provision of Specification 4.0.3 are applicable, it permits the flexibility to defer declaring the testing requirement not met in accordance with Specification 4.0.3 when testing has not been completed within the testing interval (including the allowance of Specification 4.0.2 if invoked by Section 6.8 specifications).

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Failure to comply with the specified frequency for a Surveillance Requirement is expected to be an infrequent occurrence. Use of the delay period established by Specification 4.0.3 is a flexibility which is **NOT** intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65 (a)(4) and its implementation guidance, NRC Regulatory Guide 1.160, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants. This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component.

A missed Surveillance for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All cases of a missed Surveillance will be placed in the licensee's Corrective Action Program.

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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 Limiting Condition of Operation 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 Limiting Condition of Operation 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 Specification 4.0.1.

Missed surveillance tests are reportable when the surveillance interval plus allowed surveillance interval extension, plus the LCO action statement time is exceeded. This means that a condition prohibited by the TS existed for a period of time longer than allowed by TS. If a TS surveillance is missed including the grace period, the equipment is inoperable. The TS LCO Action Statement is entered. If the time allowed by the action statement is exceeded, then it is reportable as a condition prohibited by the TS. The event is reportable even though the surveillance is subsequently satisfactorily performed. For example, if a TS requires a 31 day surveillance, and the grace period (25 %) is 7 days, and the equipment would be inoperable 38 days after the last surveillance. If the LCO allows 72 hours to restore the inoperable equipment to OPERABLE status (to perform a satisfactory surveillance), the missed surveillance would be reportable at the end of the 31 days + 7 days + 72 hours.

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If the allowable outage time limits of the ACTION requirements are less than 24 hours or a shutdown is required to comply with ACTION requirements, e.g., Specification 3.0.3, a 24 hour allowance is provided to permit a delay in implementing the ACTION requirements. This provides an adequate time limit to complete Surveillance Requirements that have **NOT** been performed. The purpose of this allowance is to permit the completion of a surveillance before a shutdown is required to comply with ACTION requirements or before other remedial measures would be required that may preclude completion of a surveillance. The basis for this allowance includes consideration for plant conditions, adequate planning, availability of personnel, the time required to perform the surveillance, and the safety significance of the delay in completing the required surveillance. The provision also provides a time limit for the completion of Surveillance Requirements that become applicable as a consequence of MODE changes imposed by ACTION requirements and for completing Surveillance Requirements that are applicable when an exception to the requirements of Specification 4.0.4 is allowed. If a surveillance is **NOT** completed within the 24-hour allowance, the time limits of the ACTION requirements are applicable at that time. When a surveillance is performed within the 24-hour allowance and the Surveillance Requirements are **NOT** met, the time limits of the ACTION requirements are applicable at the time that the surveillance is terminated.

Surveillance Requirements do **NOT** have to be performed on inoperable equipment because the ACTION requirements define the remedial measures that apply. However, the Surveillance Requirements have to be met to demonstrate that inoperable equipment has been restored to OPERABLE status.

Specification 4.0.4 establishes the requirement that all applicable surveillances must be met before entry into an OPERATIONAL MODE or other condition of operation specified in the Applicability statement. The purpose of this specification is to ensure that system and component OPERABILITY requirements or parameter limits are met before entry into a MODE or condition for which these systems and components ensure safe operation of the facility. This provision applies to changes in OPERATIONAL MODES or other specified conditions associated with plant shutdown as well as startup.

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Under the provisions of this specification, the applicable Surveillance Requirements must be performed within the specified surveillance interval to ensure that the Limiting Conditions for Operation are met during initial plant startup or following a plant outage.

When a shutdown is required to comply with ACTION requirements, the provisions of Specification 4.0.4 do **NOT** apply because this would delay placing the facility in a lower MODE of operation.

Specification 4.0.5 establishes the requirement that in-service inspection of ASME Code Class 1, 2, and 3 components shall be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda as required by 10 CFR 50.55a.

This Specification includes a clarification of the frequencies for performing the in-service inspection activities required by Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda. This clarification is provided to ensure consistency in surveillance intervals throughout the Technical Specifications and to remove any ambiguities relative to the frequencies for performing the required in-service inspection activities.

The Westinghouse Owners Group submitted Topical Report (TR) WCAP-15666, “Extension of Reactor Coolant Pump Motor Flywheel Examination,” dated July 2001 for NRC staff review. The NRC approved the TR by a Safety Evaluation dated May 5, 2003 revising the reactor coolant pump flywheel inspection interval to a maximum of 20 years. **NO** extension of this interval is allowed under Specification 4.0.2.

Specification 4.0.6 delineates the applicability of the surveillance activities to Unit 3 and Unit 4 operations.

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3/4.1 Reactivity Control Systems

3/4.1.1 Boration Control

3/4.1.1.1 &
3/4.1.1.2 Shutdown Margin

A sufficient SHUTDOWN MARGIN ensures that: (1) The reactor can be made subcritical from all operating conditions, (2) The reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and (3) The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

SHUTDOWN MARGIN requirements vary throughout core life as a function of fuel depletion, RCS boron concentration, and RCS Tavg. With Tavg greater than 200°F, the most restrictive condition occurs at EOL, with Tavg at **NO** load operating temperature, and is associated with a postulated steam line break accident and resulting uncontrolled RCS cooldown. The COLR provides a curve (formerly TS Figure 3.1-1) showing the SHUTDOWN MARGIN equivalent to 1.77% $\Delta k/k$ at the end-of-core-life with respect to an uncontrolled cooldown. Accordingly, the SHUTDOWN MARGIN requirement is based upon this limiting condition and is consistent with UFSAR safety analysis assumptions.

The COLR figure provides a separate curve showing the minimum SHUTDOWN MARGIN equivalent to 1.77% $\Delta k/k$ in MODE 4 without a Reactor Coolant Pump running. The reduced RCS mixing volume in this condition requires a higher minimum SHUTDOWN MARGIN is required to assure adequate operator response time is available to identify and terminate an inadvertent dilution event prior to loss of all SHUTDOWN MARGIN. With Tavg less than 200°F, a SHUTDOWN MARGIN equivalent to 1.77% $\Delta k/k$ is required at all times to assure adequate operator response time is available to identify and terminate an inadvertent dilution event in MODE 5 prior to loss of all SHUTDOWN MARGIN. Former TS Figure 3.1-1 titled Required Shutdown Margin versus Reactor Coolant Boron Concentration has been moved to the COLR per Amendments 247 and 243.

The boron rate requirement of 16 gpm of 3.0 wt% (5245 ppm) boron or equivalent ensures the capability to restore the SHUTDOWN MARGIN with one OPERABLE Charging Pump.

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3/4.1.1.3 Moderator Temperature Coefficient

The limitations on Moderator Temperature Coefficient (MTC) are provided to ensure that the value of this coefficient remains within the limiting condition assumed in the UFSAR accident and transient analyses.

The MTC values of this specification are applicable to a specific set of plant conditions; accordingly, verification of MTC values at conditions other than those explicitly stated will require extrapolation to those conditions in order to permit an accurate comparison.

The most negative MTC value equivalent to the most positive Moderator Density Coefficient (MDC), was obtained by incrementally correcting the MDC used in the UFSAR analyses to nominal operating conditions. These corrections involved subtracting the incremental change in the MDC associated with a core condition of all rods inserted (most positive MDC) to an all rods withdrawn condition and, a conversion for the rate of change of moderator density with temperature at RATED THERMAL POWER conditions. This value of the MDC was then transformed into the limiting End Of Cycle Life (EOL) MTC value in the COLR. The 300 ppm surveillance limit MTC value in the COLR represents a conservative value (with corrections for burnup and soluble boron) at a core condition of 300 ppm equilibrium boron concentration and is obtained by making these corrections to the limiting EOL MTC value in the COLR. These limiting MTC values have been moved to the COLR per Amendments 247 and 243.

The Surveillance Requirements for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits since this coefficient changes slowly due principally to the reduction in RCS boron concentration associated with fuel burnup.

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3/4.1.1.4 Minimum Temperature for Criticality

This Specification ensures that the reactor will **NOT** be made critical with the Reactor Coolant System average temperature less than 541°F. This limitation is required to ensure: (1) The Moderator Temperature Coefficient is within its analyzed temperature range, (2) The trip instrumentation is within its normal operating range, (3) The Pressurizer is capable of being in an OPERABLE status with a steam bubble, and (4) The reactor vessel is above its minimum RT_{NDT} temperature.

3/4.1.2 Boration Systems

The Boron Injection System ensures that negative reactivity control is available during each MODE of facility operation. The components required to perform this function include: (1) Borated water sources, (2) Charging Pumps, (3) Separate flow paths, and (4) Boric Acid Transfer Pumps.

With the RCS average temperature above 200°F, a minimum of two boron injection flow paths are required to ensure single functional capability in the event an assumed failure renders one of the flow paths inoperable. One flow path from the Charging Pump discharge is acceptable since the flow path components subject to an active failure are upstream of the Charging Pumps.

The boration flow path specification allows the RWST and the Boric Acid Storage Tank to be the boron sources. Due to the lower boron concentration in the RWST, borating the RCS from this source is less effective than borating from the Boric Acid Tank and additional time may be required to achieve the desired SHUTDOWN MARGIN required by ACTION statement restrictions. ACTION times allow for an orderly sequential shutdown of both units when the inoperability of a components affects both units with equal severity. When a single unit is affected, the time to be in HOT STANDBY is 8 hours. When an ACTION statement requires a dual unit shutdown, the time to be in HOT STANDBY is 16 hours.

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The ACTION Statement restrictions for the boration flow paths allow continued operation in MODE 1 for a limited time period with either boration source flow path or the normal flow path to the RCS (via the Regenerative Heat Exchanger) inoperable. In this case, the plant capability to borate and charge into the RCS is limited and the potential operational impact of this limitation on MODE 1 operation must be addressed. With both the flow path from the Boric Acid Tanks and the Regenerative Heat Exchanger flow path inoperable, immediate initiation of action to go to COLD SHUTDOWN is required but **NO** time is specified for the mode reduction due to the reduced plant capability with these flow paths inoperable.

Two Charging Pumps are required to be OPERABLE to ensure single functional capability in the event an assumed failure renders one of the pumps or power supplies inoperable. Each bus supplying the pumps can be fed from either the Emergency Diesel Generator or the offsite grid through a Startup Transformer.

The boration capability of either flow path is sufficient to provide the required SHUTDOWN MARGIN in accordance with the COLR from expected operating conditions after xenon decay and cooldown to 200°F. The maximum expected boration capability requirement occurs at EOL peak xenon conditions without letdown such that boration occurs only during the makeup provided for coolant contraction. This requirement can be met for a range of boric acid concentrations in the Boric Acid Tank and the Refueling Water Storage Tank. The range of Boric Acid Tanks requirements is defined by Technical Specification 3.1.2.5.

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The required fluid volume in the Boric Acid Storage Tank is specified as a function of boric acid concentration in weight % as shown in Technical Specification Figure 3.1-2. The minimum volumes listed for one unit operation include uncertainty, 2,900 gallons for shutdown and combined volume of all available boric acid storage tanks assuming an RWST concentration of 2400 ppm or greater. The minimum volumes listed for two unit operation include uncertainty, and combined volume of all available Boric Acid Storage Tanks assuming an RWST concentration of 2400 ppm or greater. Any configuration in the acceptable unit(s) operation region from TS Figure 3.1-2 will provide sufficient boric acid delivery to maintain required SHUTDOWN MARGIN.

With the RCS temperature below 200°F, one Boron Injection Source Flow Path is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the additional restrictions prohibiting CORE ALTERATIONS and positive reactivity changes in the event the single boron injection system source flow path becomes inoperable.

During MODES 5 and 6, the charging pump specified for the boration flow paths in TS LCO 3.1.2.1 is **NOT** required to be OPERABLE (Reference 1). The operability requirements for charging pumps is contained in TS LCO 3.1.2.3, which applies in MODES 1, 2, 3, and 4 only. To meet TS LCO 3.1.2.1, the charging pump is required to be functional or capable of performing its specified function.

The boron capability required below 200°F is sufficient to provide a SHUTDOWN MARGIN of 1.77% $\Delta k/k$ after xenon decay and cooldown from 200°F to 140°F. This condition requires either 2,900 gallons of at least 3.0 wt% (5245 ppm) borated water per unit from the Boric Acid Storage Tanks or 20,000 gallons of between 2400 and 2600 ppm borated water from the RWST.

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When initiating cooldown from COLD SHUTDOWN to REFUELING conditions, the boration strategy should use either boration without Letdown concurrent with cooldown using makeup from either the BAT or the RWST. Boration via feed-and -bleed using makeup from the RWST may also be implemented. Note that boration without Letdown concurrent with cooldown using makeup from the BAT and boration via feed-and-bleed using makeup from the RWST provide the greatest capability; however, all three alignments are permissible and ensure shutdown margin requirements are met.

The charging pumps are demonstrated to be OPERABLE by testing as required by the ASME OM code or by specific surveillance requirements in the specification. These requirements are adequate to determine OPERABILITY because **NO** safety analysis assumption relating to the charging pump performance is more restrictive than these Acceptance Criteria for the pumps.

During MODES 5 and 6, there are **NO** specific Surveillance Requirements that must be met for the charging pumps. During these MODES, the required charging pump must be functional or capable for performing its specified function. (Reference 1)

The RWST boron concentration (2400-2600 ppm) in conjunction with the Recirculation pH Control System (TS 3/4.6.3) ensures that the Containment Sump pH will be greater than 7.0 following a LOCA. The basic solution minimizes the evolution of iodine and the effect of chloride and caustic stress corrosion on mechanical systems and components. The temperature requirements for the RWST are based on the containment integrity and large break LOCA analysis assumptions.

The OPERABILITY of one Boron Injection Flowpath during REFUELING ensures that this system is available for reactivity control while in MODE 6. Components within the flowpath, e.g., Boric Acid Transfer Pumps or Charging Pumps, must be capable of being powered by an OPERABLE emergency power source, even if the equipment is **NOT** required to operate.

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The OPERABILITY requirement of 62°F and corresponding surveillance intervals associated with the Boric Acid Tank System ensures that the solubility of the boron solution will be maintained. The temperature limit of 62°F includes a 5°F margin over the 57°F solubility limit of 4.0 wt.% boric acid. Portable instrumentation may be used to measure the temperature of the rooms containing boric acid sources and flow paths.

(Reference 1) AR 1755509 Condition Evaluation.

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3/4.1.3 Movable Control Assemblies

The Specifications of this section ensure that: (1) Acceptable Power Distribution Limits are maintained, (2) The minimum SHUTDOWN MARGIN is maintained, and (3) The potential effects of rod misalignment on associated accident analyses are limited. OPERABILITY of the Control Rod Position Indicators is required to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits. OPERABLE condition for the Analog Rod Position Indicators is defined as being capable of indicating rod position to within the Allowed Rod Misalignment of Specification 3.1.3.1 of the demand counter position. For the Shutdown Banks and Control Banks A and B, the Position Indication requirement is defined as the Group Demand Counter indicated position between 0 and 30 steps withdrawn inclusive, and between 200 steps withdrawn and All Rods Out (ARO) inclusive. This permits the operator to verify that the control rods in these banks are either fully withdrawn or fully inserted, the normal operating modes for these banks. Knowledge of these bank positions in these two areas satisfies all accident analysis assumptions concerning their position. For Control Banks C and D, the Position Indication requirement is defined as the group demand counter indicated position between 0 steps withdrawn and All Rods Out (ARO) inclusive.

The increase in the Allowable Rod Misalignment below 90% or Rated Thermal Power is as a result of the increase in the Peaking Factor Limits as reactor power is reduced.

Comparison of the Group Demand Counters to the Bank Insertion Limits with verification of rod position with the Analog Rod Position Indicators (after thermal soak after rod motion) is sufficient verification that the control rods are above the Insertion Limits.

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Rod position indication is provided by two methods: a digital count of actuating pulses which shows demand position of the banks and a linear position indicator Linear Variable Differential Transformer which indicates the actual rod position. The relative accuracy of the linear position indicator Linear Variable Differential Transformer is such that, with the most adverse error, an alarm will be actuated if any two rods within a bank deviate by more than 24 steps for rods in motion and 12 steps for rods at rest. Complete rod misalignment (12 feet out of alignment with its bank) does **NOT** result in exceeding core limits in steady state operation at RATED THERMAL POWER. If the condition cannot be readily corrected, the specified reduction in power to 75% will insure that design margins to core limits will be maintained under both steady-state and anticipated transient conditions. The 8-hour permissible limit on rod misalignment is short with respect to the probability of an independent accident.

Amendments 237 and 232 issued 1/28/2008 approved the use of an alternate method, other than the Movable Incore Detectors, to monitor the position of a Control Rod or Shutdown Rod in the event of a problem with the Analog Rod Position Indication System. The use of the alternate method is limited to one inoperable rod position indicator per unit and shall only be allowed until an entry into MODE 3 to implement repairs of the inoperable Rod Position Indicator (RPI). The alternate method monitors the stationary gripper coil for the Control Rod or Shutdown Rod with an inoperable RPI. This alternate method will be implemented by a Temporary Configuration Change. A display will be provided to track the stationary gripper coil current of the Control Rod Drive Mechanism (CRDM) on the non indicating rod measured as an equivalent voltage. The equivalent gripper coil voltage is displayed in the Control Room and is programmed for a high and low voltage alarm to indicate a potential unintended rod movement.

In accordance with TS 3.1.3.2 Action a.2.a), the position of the non-indicating rod is required to be determined indirectly by the Movable Incore Detectors within 8 hours of declaring the RPI inoperable. After initial confirmation of the position of the non indicating rod, TS 3.1.3.2 Action a.2.a) requires confirmation of the position for the non-indicating control rod or shutdown rod at least once every 31 Effective Full Power days using the Movable Incore System.

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The DCS RPI displays utilize user friendly graphical and digital displays familiar to operators in a format similar to and consistent with other DCS monitored plant parameters such as the Safety Parameter Display.

The addition of the DCS monitoring capabilities of the Rod Position Indication (RPI) System (as displayed on the DCS screens) provides an equivalent method to the panel meters for reading rod position. Therefore the DCS can be used to obtain control rod analog position information for shiftly control rod position channel checks.

Analog rod position indication, using NARPI modules, includes a Tcomp signal input to DCS. If the Tcomp signal is lost, DCS control processors will default to a temperature value output for 100% thermal power. Both the panel meter and the DCS display will be adjusted accordingly. This is a conservative measure and will only apply during calibration activities or a postulated failure of the DCS network backbone. Verification of analog RPI OPERABLITY remains to be defined as within the Allowed Rod Misalignment of Specification 3.1.3.1.

TS 3.1.3.2 Action a.2.b) requires verification that the non-indicating rod has **NOT** moved by verifying the gripper coil voltage has **NOT** changed state at least once every 8 hours. This 8 hour surveillance period is consistent with the current operational requirements of control rod position determination using the Movable Incore Detectors for a non-indicating rod and is more frequent than the normal 12-hour requirement for position determination specified in TS 4.1.3.1.1.

If the gripper coil has changed state indicating a potential unintended rod movement, a determination of the position for the non-indicating control rod or shutdown rod is required to be made within 1 hour by using the Movable Incore Detector System as required by TS 3.1.3.2 Action a.2.a).

If the rod with the inoperable position indicator is moved greater than 12 steps, TS 3.1.3.2 Action a.2.a) will determine the position of the non-indicating rod indirectly by the Movable Incore Detectors within 1 hour. This provision provides assurance that any unintended rod movement is identified in a timely manner.

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TS 3.1.3.2 Action a.2.c) requires the use of the Movable Incore Detector System to verify rod position prior to increasing thermal power above 50 percent Rated Thermal Power (RTP) and within 8 hours of reaching 100 percent RTP. These provisions are intended to establish and confirm the position of the rod with the inoperable RPI to ensure that power distribution requirements are **NOT** violated.

The ACTION Statements which permit limited variations from the basic requirements are accompanied by additional restrictions which ensure that the original design criteria are met. Misalignment of a rod requires measurement of peaking factors and a restriction in THERMAL POWER. These restrictions provide assurance of fuel rod integrity during continued operation. In addition, those safety analyses affected by a misaligned rod are reevaluated to confirm that the results remain valid during future operation.

The maximum rod drop time restriction is consistent with the assumed rod drop time used in the safety analyses. Measurement with Tavg greater than or equal to 500°F and with all Reactor Coolant Pumps operating ensures that the measured drop times will be representative of insertion times experienced during a Reactor Trip at operating conditions.

Control rod positions and OPERABILITY of the Rod Position Indicators are required to be verified in accordance with the Surveillance Frequency Control Program with more frequent verifications required if an automatic monitoring channel is inoperable. These verification frequencies are adequate for assuring that the applicable LCOs are satisfied.

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3/4.2 Power Distribution Limits

The specifications of this section provide assurance of fuel integrity during Condition I (Normal Operation) and II (Incidents of Moderate Frequency) events by: (1) Maintaining the minimum DNBR in the core greater than or equal to the applicable design limit during normal operation and in short-term transients, and (2) Limiting the fission gas release, fuel pellet temperature, and cladding mechanical properties to within assumed design criteria. In addition, limiting the peak linear power density during Condition I events provides assurance that the initial conditions assumed for the LOCA analyses are met and the ECCS acceptance criteria limit of 2200°F is **NOT** exceeded.

The definitions of certain hot channel and peaking factors as used in these specifications are as follows:

$F_Q(Z)$ Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod at core elevation Z divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods;

$F^N_{\Delta H}$ Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power; and

$F_{XY}(Z)$ Radial Peaking Factor, is defined as the ratio of peak power density to average power density in the horizontal plane at core elevation Z.

3/4.2.1 Axial Flux Difference

The limits on AXIAL FLUX DIFFERENCE (AFD) assure that the $F_Q(Z)$ limit defined in the CORE OPERATING LIMITS REPORT times the normalized axial peaking factor is **NOT** exceeded during either normal operation or in the event of xenon redistribution following power changes.

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Target flux difference is determined at equilibrium xenon conditions. The full-length rods may be positioned within the core in accordance with their respective insertion limits and should be inserted near their normal position for steady-state operation at high power levels. The value of the target flux difference obtained under these conditions divided by the fraction of RATED THERMAL POWER is the target flux difference at RATED THERMAL POWER for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RATED THERMAL POWER value by the appropriate fractional THERMAL POWER level. The periodic updating of the target flux difference value is necessary to reflect core burnup considerations.

At power level below PT, the limits on AFD are specified in the CORE OPERATING LIMITS REPORT (COLR) for RAOC operation. These limits were calculated in a manner such that expected operational transients, e.g., load follow operations, would **NOT** result in the AFD deviating outside of those limits. However, in the event that such a deviation occurs, a 15 minute period of time allowed outside of the AFD limits at reduced power levels will **NOT** result in significant xenon redistribution such that the envelope of peaking factors would change sufficiently to prevent operation in the vicinity of the power level.

With PT greater than 100%, two modes are permissible: 1) RAOC with fixed AFD limits as a function of reactor power level, and 2) Base Load operation which is defined as the maintenance of the AFD within a band about a target value. Both the fixed AFD limits for RAOC operation and the target band for Base Load operation are defined in the COLR and the Peaking Factor Limit Report, respectively. However, it is possible during extended load following maneuvers that the AFD limits may result in restrictions in the maximum allowed power or AFD in order to guarantee operation with FQ(Z) less than its limiting value. Therefore, PT is calculated to be less than 100%. To allow operation at the maximum permissible value above PT Base Load operation restricts the indicated AFD to a relative small target band and power swings. For Base Load operation, it is expected that the plant will operate within the target band.

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3/4.2.1 (Continued)

Operation outside of the target band for the short time period allowed (15 minutes) will **NOT** result in significant xenon redistribution such that the envelope of peaking factors will change sufficiently to prohibit continued operation in the power region defined above. To assure that there is **NO** residual xenon redistribution impact from past operation on the Base Load operation, a 24-hour waiting period within a defined range of PT and AFD allowed by RAOC is necessary. During this period, load changes and rod motion are restricted to that allowed by the Base Load requirement. After the waiting period, extended Base Load operation is permissible.

Provisions for monitoring the AFD on an automatic basis are derived from the plant process computer through the AFD Monitoring Alarm. The computer monitors the OPERABLE excore detector outputs and provides an alarm message immediately if the AFD for two or more OPERABLE excore channels are: 1) Outside the acceptable AFD (for RAOC operation), or 2) Outside the acceptable AFD target band (for Base Load operation). These alarms are active when power is greater than: 1) 50% of RATED THERMAL POWER (for RAOC operation), or 2) PT (Base Load operation). Penalty deviation minutes for Base Load operation are **NOT** accumulated based on the short time period during which operation outside of the target band is allowed.

3/4.2.2
&
3/4.2.3 Heat Flux Hot Channel Factor and Nuclear Enthalpy Rise Hot Channel Factor

The limits on Heat Flux Hot Channel Factor and Nuclear Enthalpy Rise Hot Channel Factor ensure that: (1) The design limits on peak local power density and minimum DNBR are **NOT** exceeded, and (2) In the event of a LOCA the peak fuel clad temperature will **NOT** exceed the 2200°F ECCS acceptance criteria limit. The LOCA peak fuel clad temperature limit may be sensitive to the number of steam generator tubes plugged.

$F_Q(Z)$, Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod at core elevation Z divided by the average fuel rod heat flux.

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3/4.2.2 & 3/4.2.3 (Continued)

$F^N_{\Delta H}$ Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.

Each of these is measurable but will normally only be determined periodically as specified in Specifications 4.2.2 and 4.2.3. This periodic surveillance is sufficient to ensure that the limits are maintained provided:

a. Control rods in a single group move together with **NO** individual rod insertion differing by more than ± 12 steps, indicated, from the group demand position;

b. Control rod groups are sequenced with overlapping groups as described in Specification 3.1.3.6;

c. The control rod insertion limits of Specifications 3.1.3.5 and 3.1.3.6 are maintained; and

d. The axial power distribution, expressed in terms of AXIAL FLUX DIFFERENCE, is maintained within the limits.

When an F_Q measurement is taken, both experimental error and manufacturing tolerance must be allowed for. Five percent is the appropriate allowance for a full core map taken with the movable incore detector flux mapping system and three percent is the appropriate allowance for manufacturing tolerance. These uncertainties only apply if the map is taken for purposes other than the determination of P_{BL} and P_RB.

$F^N_{\Delta H}$ will be maintained within its limits provided Conditions a. through d. above are maintained.

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3/4.2.2 & 3/4.2.3 (Continued)

In the specified limit of $F^N_{\Delta H}$, there is an 8 percent allowance for uncertainties which means that normal operation of the core is expected to result in $F^N_{\Delta H} \leq F^{RTP}_{\Delta H}/1.08$, where $F^{RTP}_{\Delta H}$ is the $F^N_{\Delta H}$ limit at RATED THERMAL POWER (RTP) specified in the CORE OPERATING LIMITS REPORT. The logic behind the larger uncertainty in this case is that (a) Normal perturbations in the radial power shape (e.g., rod misalignment) affect $F^N_{\Delta H}$, in most cases without necessarily affecting F_Q, (b) Although the operator has a direct influence on F_Q through movement of rods, and can limit it to the desired value, he has **NO** direct control over $F^N_{\Delta H}$, and (c) An error in the prediction for radial power shape, which may be detected during startup physics tests can be compensated for in F_Q by tighter axial control, but compensation for $F^N_{\Delta H}$ is less readily available. When a measurement of $F^N_{\Delta H}$, is taken, experimental error must be allowed for and 4% is the appropriate allowance for a full core map taken with the movable incore detector flux mapping system.

The following are independent augmented surveillance methods used to ensure peaking factors are acceptable for continued operation above Threshold Power, P_T:

Base Load - This method uses the following equation to determine peaking factors:

$F_{QBL} = F_Q(Z)$ measured x 1.09 x $W(Z)_{BL}$

where: $W(Z)_{BL}$ = accounts for power shapes;

1.09 = accounts for uncertainty;

$F_Q(Z)$ = measured data;

F_{QBL} = Base load peaking factor.

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3/4.2.2 & 3/4.2.3 (Continued)

The analytically determined $[F_Q]^P$ is formulated to generate limiting shapes for all load follow maneuvers consistent with control to a ± 5% band about the target flux difference. For Base Load operation the severity of the shapes that need to be considered is significantly reduced relative to load follow operation.

The severity of possible shapes is small due to the restrictions imposed by Sections 4.2.2.3. To quantify the effect of the limiting transients which could occur during Base Load operation, the function $W(Z)_{BL}$ is calculated from the following relationship:

$$W(Z)_{BL} = \text{Max}\left[\frac{F_Q(Z)\ \text{(Base Load Case(s), 150 MWD/T)}}{F_Q(Z)\ \ \text{(ARO, 150 MWD/T)}}, \frac{F_Q(Z)\ \text{(Base Case(s),85\% EOL BU)}}{F_Q(Z)\ \ \text{(ARO, 85\% BOL BU)}}\right]$$

Radial Burndown - This method uses the following equation to determine peaking factors.

$F_Q(Z)_{R.B.} = F_{xy}(Z)_{measured} \times F_Z(Z) \times 1.09$

where: 1.09 = accounts for uncertainty

$F_Z(Z)$ = accounts for axial power shapes

$F_{xy}(Z)_{measured}$ = ratio of peak power density to average power density at elevation(Z)

$F_Q(Z)_{R.B.}$ = Radial Burndown Peaking Factor.

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3/4.2.2 & 3/4.2.3 (Continued)

For Radial Burndown operation the full spectrum of possible shapes consistent with control to a ±5% Delta-I band needs to be considered in determining power capability. Accordingly, to quantify the effect of the limiting transients which could occur during Radial Burndown operation, the function $F_Z(Z)$ is calculated from the following relationship:

$F_Z(Z) = [F_Q(Z)]$ FAC Analysis/$[F_{xy}(Z)]$ ARO

The essence of the procedure is to maintain the xenon distribution in the core as close to the equilibrium full power condition as possible. This can be accomplished by using the boron system to position the full length control rods to produce the required indicated flux difference.

Above the power level of P_T, additional flux shape monitoring is required. In order to assure that the total power peaking factor, F_Q, is maintained at or below the limiting value, the movable incore instrumentation will be utilized. Thimbles are selected initially during startup physics tests so that the measurements are representative of the peak core power density. By limiting the core average axial power distribution, the total power peaking factor F_Q can be limited since all other components remain relatively; fixed. The remaining part of the total power peaking factor can be derived from incore measurements, i.e., an effective radial peaking factor, can be determined as the ratio of the total peaking factor resulting from a full core flux map and the axial peaking factor in a selected thimble.

The limiting value of $[F_j(Z)]_S$ is derived as follows:

$$[F_j(Z)]_S = \frac{[F_Q]^L \times [K(Z)]}{P_L \bar{R}_j (1+\sigma_j)(1.03)(1.07)}$$

Where:

a) $F_j(Z)$ is the normalized axial power distribution from thimble j at elevation Z.

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3/4.2.2 & 3/4.2.3 (Continued)

b) P_L is reactor thermal power expressed as a fraction of 1.

c) K(Z) is the reduction in the F_Q limit as a function of core elevation (Z) as specified in the CORE OPERATING LIMITS REPORT.

d) $[F_j\ (Z)]_s$ is the alarm setpoint for MIDS.

e) R_j, for thimble j, is determined from n=6 incore flux maps covering the full configuration of permissible rod patterns at the thermal power limit of PT.

$$\overline{R}_j = \frac{\sum_{i=1}^{n} R_{ij}}{n}$$

where

$$R_{ij} = \frac{F_{Qi}\ \text{meas.}}{[F_{ij}\ (Z)]\ \max}$$

and F_{ij} (Z) is the normalized axial distribution at elevation Z from thimble j in map i which has a measure peaking factor without uncertainties or densification allowance of F_{Qi} meas.

f) σ_j is the standard deviation, expressed as a fraction or percentage of $\overline{R}_j$ and is derived from n flux maps and the relationship below, or 0.02 (2%), whichever is greater.

$$\sigma_j = \left[\frac{\frac{1}{n-1} \sum_{i=1}^{n} \left(R_{ij} - \overline{R}_j\right)^2}{\overline{R}_j} \right]^{1/2}$$

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g) The factor 1.03 reduction in the kw/ft limit is the engineering uncertainty factor.

h) The factors (1+ σj) and 1.07 represent the margin between (Fj(Z)]L limit and the MIDS alarm setpoint [Fj(Z)]s. Since (1 +σj) is bounded by a lower limit of 1.02, there is at least a 9% reduction of the alarm setpoint. Operations are permitted in excess of the operational limit $\leq$ 4% while making power adjustment on a percent for percent basis.

3/4.2.4 Quadrant Power Tilt Ratio

The QUADRANT POWER TILT RATIO limit assures that the radial power distribution satisfies the design values used in the power capability analysis. Radial power distribution measurements are made during STARTUP testing and periodically during power operation.

The limit of 1.02, at which corrective action is required, provides DNB and linear heat generation rate protection with x-y plane power tilts. A limit of 1.02 was selected to provide an allowance for the uncertainty associated with the indicated power tilt.

The 2-hour time allowance for operation with a tilt condition greater than 1.02 but less than 1.09 is provided to allow identification and correction of a dropped or misaligned control rod. In the event such action does **NOT** correct the tilt, the margin for uncertainty on $F_Q(Z)$ is reinstated by reducing the maximum allowed power by 3% for each percent of tilt in excess of 1.

For purposes of monitoring QUADRANT POWER TILT RATIO when one excore detector is inoperable, the Movable Incore Detectors or incore thermocouple map are used to confirm that the normalized symmetric power distribution is consistent with the QUADRANT POWER TILT RATIO. The incore detector monitoring is done with a full incore flux map or two sets of four symmetric thimbles. The two sets of four symmetric thimbles is a unique set of eight detector locations. These locations are C-8, E-5, E-11, H 3, H 13, L-5, L-11, N-8.

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3/4.2.5 DNB Parameters

The limits on the DNB-related parameters assure that each of the parameters are maintained within the normal steady-state envelope of operation assumed in the transient and accident analyses. The limits are consistent with the initial UFSAR assumptions and have been analytically demonstrated adequate to maintain a minimum DNBR above the applicable design limits throughout each analyzed transient. The limits for Tavg and pressurizer pressure have been moved to the COLR. The measured RCS flow value of 270,000 gpm corresponds to a Thermal Design Flow of 260,700 gpm with an allowance of 3.5% to accommodate calorimetric measurement uncertainty.

The periodic surveillance of these parameters through instrument readout, required by Technical Specification (TS) Surveillance Requirements (SR) 4.2.5.1 and 4.2.5.2, ensures that the parameters are restored within their limits following load changes and other expected transient operation. The periodic measurement of the RCS total flow rate, required by TS SR 4.2.5.4, ensures that the DNB-related flow assumption is met and ensures correlation of the flow indication channels with measured flow. The indicated percent flow surveillance, required by TS SR 4.2.5.2, provides sufficient verification that flow degradation has **NOT** occurred. An indicated percent flow which is greater than the thermal design flow plus instrument channel inaccuracies and parallax errors is acceptable for the surveillance on RCS flow required by TS SR 4.2.5.2. To minimize measurement uncertainties it is assumed that the RCS flow channel outputs are averaged.

The surveillance frequencies are controlled under the Surveillance Frequency Control Program.

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3/4.3 Instrumentation

3/4.3.1
&
3/4.3.2 Reactor Trip System and Engineered Safety Features Actuation System Instrumentation

The OPERABILITY of the Reactor Trip System (RTS) and the Engineered Safety Features Actuation System (ESFAS) instrumentation and interlocks ensures that: (1) The associated ACTION and/or reactor trip will be initiated when the parameter monitored by each channel or combination thereof reaches its Trip Setpoint, (2) The specified coincidence logic is maintained, (3) Sufficient redundancy is maintained to permit a channel to be out-of-service for testing or maintenance (due to plant specific design, pulling fuses and using jumpers may be used to place channels in trip), and (4) Sufficient system functional capability is available from diverse parameters.

The OPERABILITY of these systems is required to provide the overall reliability, redundancy, and diversity assumed available in the facility design for the protection and mitigation of accident and transient conditions. The integrated operation of each of these systems is consistent with the assumptions used in the safety analyses. The Surveillance Requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. Periodic surveillance tests demonstrate this capability. The surveillance frequencies are controlled under the Surveillance Frequency Control Program.

Under some pressure and temperature conditions, certain surveillances for Safety Injection, Steam Line Isolation, and ESFAS interlocks can **NOT** be performed because of the system design. Allowance to enter MODE 3 is provided by Note (3) to Table 4.3-2 under these conditions as long as the surveillances are completed within 96 hours of entering MODE 3. The applicable Surveillance Requirements are those associated with Functional Units 1.b, 1.d, 1.e, 1.f, 4.b, 4.d, 8.a, and 8.b.

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3/4.3.1 & 3/4.3.2 (Continued)

If the Reactor Trip Breakers (RTB) are closed and the Rod Control System is capable of withdrawing the Control Rods, then Source Range Instrumentation is required to support Technical Specification (TS) 3.3.1, Table 3.3-1, Item 4c. This is specified by the single asterisk note and the requirement in the table for the trip function. Otherwise, Item 4b of Table 3.3-1 applies. The double asterisk note of Item 4b allows the use of the Gammametrics only if the RTBs are open. If the RTBs are closed but the Rod Control System is **NOT** capable of withdrawing rods, then Item 4b does **NOT** allow Gammametrics to take the place of source range instruments. Item 4b does **NOT** require the trip function to be OPERABLE.

The Instrumentation Trip Setpoints specified in TS Table 3.3-3 are the nominal values at which the bistables are set for each functional unit. The setpoint is considered to be adjusted consistent with the Trip Setpoint when the as measured setpoint is within the band allowed for calibration accuracy. Although the degraded voltage channel for Item 7.c consists of definite time (ITE) and inverse time (IAV) relays, the setpoint specified in Table 3.3-3 is only applicable to the definite time delay relays (Reference: CR 00-2301). The original protection scheme consisted of inverse time voltage relays; but based on operational experience, it was found that the settings of these relays drifted in a non-conservative direction. In 1992, to improve repeatability and to reduce potential harmful effects due to setpoint drifts, ITE definite time delay relays were added to the protection scheme to protect the 480 V alternating current (AC) system from adverse effects of a sustained degraded voltage condition. The IAV relays protect the system from adverse effects of a brief large voltage transient. The IAV relay settings are such that they should **NOT** operate before the ITE relays. The degraded voltage protection is ensured by the definite time delay relays with the setpoints specified in TS Table 3.3-3, Item 7.c (References: L-92-097 dated 4/21/92, and L-92-215 dated 7/29/92). These changes were approved by NRC letter dated August 20, 1992, and implemented by Amendment Nos. 152 and 147.

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3/4.3.1 & 3/4.3.2 (Continued)

To accommodate instrument drift that may occur between operational tests and the accuracy to which setpoints can be measured and calibrated, allowances are provided for in the Trip Setpoint and Allowable Values in accordance with the setpoint methodology described in WCAPs 17070-P (for Functional Units 1f, 4d, 5c and 6b) and 12745. Surveillance criteria have been determined and are controlled in plant procedures and in design documents. The surveillance criteria ensure that instruments which are **NOT** operating within the assumptions of the setpoint calculations are identified. An instrument channel is considered OPERABLE when the surveillance is within the Allowable Value and the channel is capable of being calibrated in accordance with procedures to within the As Left tolerance. If the As Found setpoint is outside of the As Found tolerance, the occurrence will be entered into the Corrective Action Program (CAP) and the channel will be evaluated to verify that it is functioning as required before returning the channel to service. The CAP evaluation does not need to be completed prior to returning the channel to service if it can be recalibrated to within the as-left tolerance. In this case, the functional verification is performed in the field during the surveillance test. Sensor and other instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes.

There is a small statistical probability that a properly functioning device will drift beyond determined surveillance criteria. Infrequent drift outside the surveillance criteria are expected. Excessive rack or sensor drift that is more than occasional may be indicative of more serious problems and should warrant further investigation.

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3/4.3.1 & 3/4.3.2 (Continued)

The Trip Setpoints used in the bistables for Functional Units 1f, 4d, 5c, and 6b are based on the analytical limits stated in WCAP-17070-P and UFSAR Section 7.2. The selection of these analytical limits is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49, the Trip Setpoints are conservative with respect to the analytical limits. A detailed description of the methodology used to determine the ESFAS Trip Setpoint, Allowable Value, As Left tolerance, and As Found tolerance including their explicit uncertainties, is provided in WCAP-17070-P and UFSAR Section 7.2 which incorporates all of the known uncertainties applicable to these functional units. The magnitudes of these uncertainties are factored into the determination of each ESFAS Trip Setpoint and corresponding Allowable Value.

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3/4.3.1 & 3/4.3.2 (Continued)

The Trip Setpoint for Functional Units 1f, 4d, 5c, and 6b is the value at which the bistables are set and is the expected value to be achieved during calibration. The Trip Setpoint value ensures the safety analysis limits are met for the surveillance interval selected when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the As Left Trip Setpoint value is within the As Left tolerance for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration accuracy). The Trip Setpoint value is therefore considered a "nominal value" (i.e., expressed as a value without inequalities) for the purposes of the ANALOG/DIGITAL CHANNEL OPERATIONAL TEST (COT) and CHANNEL CALIBRATION. These Functional Units have been modified by two notes as identified in Table 4.3-2. Note (a) requires evaluation of channel performance for the condition where the As Found setting for the Trip Setpoint is outside of the As Found criterion. As stated above, these instances will be entered into the CAP and the channel will be evaluated to verify that it is functioning as required before returning the channel to service. Note (b) requires that the channel As Left setting must be within the As Left tolerance band. As noted above a channel is considered to be properly calibrated with the As Left Trip Setpoint value is within the As Left tolerance band for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration accuracy).

WCAP-17070-P methodology for determining analytical limits only applies to those ESFAS functions that support the safety analysis. Certain ESFAS functions such as the loss of voltage UV signal to the 480V load centers only provide equipment protection and therefore their analytical limit is **NOT** required to meet the WCAP-17070-P methodology.

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3/4.3.1 & 3/4.3.2 (Continued)

The Engineered Safety Features Actuation System senses selected plant parameters and determines whether or **NOT** predetermined limits are being exceeded. If they are, the signals are combined into logic matrices sensitive to combinations indicative of various accidents events, and transients. Once the required logic combination is completed, the system sends actuation signals to those Engineered Safety Features components whose aggregate function best serves the requirements of the condition. As an example, the following actions may be initiated by the Engineered Safety Features Actuation System to mitigate the consequences of a steam line break or loss-of-coolant accident: (1) Safety Injection pumps start and automatic valves position, (2) Reactor trip, (3) Feed water isolation, (4) Startup of the emergency diesel generators, (5) Containment spray pumps start and automatic valves position (6) Containment ventilation isolation, (7) Steam line isolation, (8) Turbine trip, (9) Auxiliary feedwater pumps start and automatic valves position, (10) Containment cooling fans start and automatic valves position, (11) Intake cooling water and component cooling water pumps start and automatic valves position, and (12) Control Room Isolation and Ventilation Systems start. This system also provides a feedwater system isolation to prevent SG overfill. Steam Generator overfill protection is **NOT** part of the Engineered Safety Features Actuation System (ESFAS), and is added to the Technical Specifications only in accordance with NRC Generic Letter 89-19.

The Steam Generator Pressure-Low and Steam Line Pressure- Low functions, items 1.f and 4.d of Table 3.3-3, are anticipatory in nature and have a typical lead/lag ratio of 50/5. The 50/5-second lead/lag function is needed to assure acceptable results for the Hot Full Power and Hot Zero Power steam line break analyses.

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3/4.3.1 & 3/4.3.2 (Continued)

Item 5 of Table 3.3-2 requires that two trains of feedwater isolation actuation logic and relays be OPERABLE in MODES 1, 2 and 3. Operability requires:

- Isolation of both the normal feedwater branch and the bypass branch lines through automatic closure of the main feedwater and main feedwater bypass flow control valves (FCV) or automatic closure of the feedwater isolation valves (FIV) during a safety injection actuation signal or high-high steam generator water level signal, and

- Two independent trains of Automatic Actuation Logic and actuation relays.

In the event that maintenance and/or in-service testing is required on a feedwater regulating valve in Mode 1, 2 and 3, the above requirements can be met by closing the isolation valve upstream of the affected feedwater regulating valve, administratively controlling the position of the isolation valve, and controlling feedwater flow with an OPERABLE feedwater regulating valve (main or bypass).

For Table 3.3-2 Functional Unit (FU) 6.d, ACTION 23(a) establishes that if a FU 6.d channel is inoperable, 48 hours are allowed to return the channel to an OPERABLE status. If the FU 6.d channel can **NOT** be returned to an OPERBLE status within 48 hours, then the next 6 hours are allowed to place the Unit in MODE 3 and an additional 6 hours are allowed to place the Unit in MODE 4. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 4 from full power conditions in an orderly manner and without challenging Unit systems. In MODE 4, the Unit does **NOT** have analyzed transients or conditions that require the explicit use of the protection function noted above.

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3/4.3.1 & 3/4.3.2 (Continued)

For Table 3.3-2 Functional Unit (FU) 6.e, ACTION 23(b) establishes that if a FU 6.e channel is inoperable, 48 hours are allowed to return the channel to an OPERABLE status. If the FU 6.e channel can **NOT** be returned to an OPERBLE status within 48 hours, then the next 6 hours are allowed to place the Unit in MODE 3. 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 Unit systems. In MODE 3, the Unit does **NOT** have analyzed transients or conditions that require the explicit use of the protection functions noted above.

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3/4.3.1 & 3/4.3.2 (Continued)

The Engineered Safety Features Actuation System interlocks perform the following functions:

- HIGH STEAM FLOW SAFETY INJECTION BLOCK - This permissive is used to block the safety injection (SI) signal generated by High Steam Line Flow coincident with Low Steam Line Pressure or Low Tavg. The permissive is generated when two out of three Low Tavg channels drop below their setpoints and the manual SI Block/Unblock switch is momentarily placed in the block position. This switch is a spring return to the normal position type. The permissive will automatically be defeated if two out of three Low Tavg channels rise above their setpoints. The permissive may be manually defeated when two out of three Low Tavg channels are below their setpoints and the manual SI Block/Unblock switch is momentarily placed in the unblock position.

- LOW PRESSURIZER PRESSURE SAFETY INJECTION BLOCK - This permissive is used to block the safety injection signals generated by Low Pressurizer Pressure and High Differential Pressure between the Steam Line Header and any Steam Line. The permissive is generated when two out of three pressurizer pressure permissive channels drop below their setpoints and the manual SI Block/Unblock switch is momentarily placed in the block position. This is the same switch that is used to manually block the High Steam Flow Safety Injection signals mentioned above. This permissive will automatically be defeated if two out of three pressurizer pressure permissive channels rise above their setpoints. The permissive may be manually defeated when two out of three pressurizer pressure permissive channels are below their setpoints and the manual SI Block/Unblock switch momentarily placed in the Unblock position.

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3/4.3.3 Monitoring Instrumentation

3/4.3.3.1 Radiation Monitoring for Plant Operations

The OPERABILITY of the radiation monitoring instrumentation for plant operations ensures that conditions indicative of potential uncontrolled radioactive releases are monitored and that appropriate actions will be automatically or manually initiated when the radiation level monitored by each channel reaches its alarm or trip setpoint.

In MODES 1-4, with both the Particulate and Gaseous Radioactivity Monitoring Systems inoperable, the isolation valves in the Containment Purge Supply and Exhaust and Instrument Air Bleed flow paths are required to be maintained closed in order to allow continued operation for up to 7 days. A note permits the instrument air flow path to be opened under administrative control in order to maintain the containment internal pressure within specified limits since it is relatively small in size and easily isolated either automatically by a safety injection signal or manually by the operator monitoring containment conditions while the valves are open.

3/4.3.3.2 Movable Incore Detectors

The OPERABILITY of the Movable Incore Detectors with the specified minimum complement of equipment ensures that the measurements obtained from use of this system accurately represent the spatial neutron flux distribution of the core. The OPERABILITY of this system is demonstrated by irradiating each detector used and determining the acceptability of its voltage curve.

For the purpose of measuring $F_Q(Z)$ or $F^N_{\Delta H}$ a full Incore flux map is used. Quarter-core flux maps, as defined in WCAP-8648, June 1976 or in the Westinghouse Single Point Calibration Technique, may be used in recalibration of the Excore Neutron Flux Detection System, and full incore flux maps or symmetric incore thimbles may be used for monitoring the QUADRANT POWER TILT RATIO when one Power Range Channel is inoperable.

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3/4.3.3.3 Accident Monitoring Instrumentation

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, Revision 3, Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident, May 1983 and NUREG-0737, Clarification of TMI Action Plan Requirements, November 1980.

Action c states that separate Action entry is allowed for each instrument. This Action has been added for clarification. The Actions of this Specification may be entered independently for each Instrument listed on Table 3.3-5. Allowable outage times of the inoperable channels of an Instrument will be tracked separately for each Instrument starting from the time the Action was entered for that Instrument.

TS Table 3.3-5, Accident Monitoring Instrumentation, instrument item 3, Reactor Coolant Outlet Temperature, T-hot and instrument item 4 Reactor Coolant Inlet Temperature, T cold, utilize the terms detector and channel. The term channel (in the context of the specification) refers to one of the two channels of QSPDS. Each channel has three detectors as inputs, one from each loop. For example, Resistance Temperature Detectors TE-3-413A, TE-3-423A, and TE-3-433A are the three detectors which feed QSPDS Channel A for Unit 3. The TOTAL NUMBER OF CHANNELS is two (with two of the three detectors required). The MINIMUM CHANNELS OPERABLE is one (with two of the three detectors.) To call a channel OPERABLE, it must have at least two of its three detectors OPERABLE. Although the minimum channels OPERABLE is one (of two), having one channel inoperable invokes Action Statement 31 (restore in 30 days or submit a Special Report in the next 14 days).

The QSPDS is configured into two channels, but it is often referred to as having two trains. In general, the term train applies only to Reactor Protection System (RPS) / Engineering Safety Feature Actuation System (ESFAS) actuation signals, i.e., there are two trains of reactor protection; each train will trip one reactor trip breaker. Train is **NOT** appropriate to QSPDS, since QSPDS serves **NO** automatic protection function.

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3/4.3.3.3 (Continued)

Technical Specification Table 3.3-5, Item 14, Incore Thermocouples (Core Exit Thermocouples), utilizes the term channel. There are **NO** channels of Incore Thermocouples as stated previously, the term Channel refers to one of the two QSPDS channels. NUREG 0737, Section II.F.2, Attachment 1, Item (3) describes what is required from instrumentation standpoint: A display should be provided with the capability for selective reading of a minimum of 16 OPERABLE thermocouples, four from each core quadrant. This description is the basis for our Technical Specification, and clarifies the requirement for Incore Thermocouples. If we have fewer than four thermocouples per core quadrant, Action 31 applies. If we have fewer than two thermocouples per quadrant, Action 32 applies. There is **NO** regulatory requirement that these two or four thermocouples per core quadrant be assigned to or divided between the two channels of QSPDS. The column heading TOTAL NO. OF CHANNELS, is also misleading for the Incore Thermocouples. There are more than four thermocouples in every core quadrant. It takes four thermocouples per core quadrant to satisfy the Technical Specifications and unrestricted operation with fewer than the TOTAL, but at least the MINIMUM is **NOT** allowed. For example, if there are only three operable thermocouples in a quadrant, in 30 days one must be fixed or a Special Report submitted within the next 14 days.

3/4.3.3.4 Deleted

3/4.3.3.5 Deleted

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3/4.3.3.6 Radioactive Gaseous Effluent Monitoring Instrumentation

The radioactive gaseous effluent instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in gaseous effluents during actual or potential releases of gaseous effluents. The Alarm/Trip Setpoints for these instruments shall be calculated and adjusted in accordance with the methodology and parameters in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20. This instrumentation also includes provisions for monitoring (and controlling) the concentrations of potentially explosive gas mixtures in the GAS DECAY TANK SYSTEM. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63, and 64 of Appendix A to 10 CFR Part 50. The sensitivity of any noble gas activity monitors used to show compliance with the gaseous effluent release requirements of Specification 3.11.2.2 shall be such that concentrations as low as 1×10^{-6} µCi/ml are measurable.

3/4.4 Reactor Coolant System

3/4.4.1 Reactor Coolant Loops and Coolant Circulation

The plant is designed to operate with all reactor coolant loops in operation and maintain DNBR above the applicable design limit during all normal operations and anticipated transients. In MODES 1 and 2 with one Reactor Coolant Loop **NOT** in operation this specification requires that the plant be in at least HOT STANDBY within 6 hours.

In MODE 3, three reactor coolant loops provide sufficient heat removal capability for removing core decay heat in the event of a bank withdrawal accident; however, a single Reactor Coolant Loop provides sufficient heat removal capacity if a bank withdrawal accident can be prevented, i.e., by opening the Reactor Trip System breakers. Single active failure considerations require that at least two loops be OPERABLE at all times.

In MODE 4, and in MODE 5 with reactor coolant loops filled, a single reactor coolant loop or RHR loop provides sufficient heat removal capability for removing decay heat, but all combinations of two loops, except two RHR loops, provide single active failure protection.

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3/4.4.1 (Continued)

In MODE 5 with Reactor Coolant Loops **NOT** filled, a single RHR Loop provides sufficient heat removal capability for removing decay heat; but the unavailability of the Steam Generators as a heat removing component, requires that at least two RHR Loops be OPERABLE.

To take credit for reactor coolant loops being filled requires the availability of at least two steam generators as heat removing components. Then if the RHR loop is lost, natural circulation will be established. If the RCS is depressurized, natural circulation cannot be established since there is **NOT** enough thermal driving head that can be established to overcome the Steam Generator U-tube voids. Therefore, loops shall **NOT** be considered filled unless the reactor coolant system has been filled and vented with **NO** intervening evolutions that could introduce air into the steam generators, and is pressurized to at least 100 psig (JPN-PTN-SEMS-95-026). The RCS loops cannot be considered a valid coolant loop if the RCS is depressurized to less than 100 psig, and two RHR loops must be OPERABLE.

The operation of one Reactor Coolant Pump (RCP) or one RHR Pump provides adequate flow to ensure mixing, prevent stratification, and produce gradual reactivity changes during boron concentration reductions in the Reactor Coolant System. The reactivity change rate associated with boron reduction will, therefore, be within the capability of operator recognition and control.

The restrictions on starting an RCP with one or more RCS Cold Legs less than or equal to 275°F are provided to prevent RCS pressure transients, caused by energy additions from the Secondary Coolant System, which could exceed the limits of Appendix G to 10 CFR Part 50. The RCS will be protected against overpressure transients and will **NOT** exceed the limits of Appendix G by either: (1) Restricting the water volume in the Pressurizer and thereby providing a volume for the reactor coolant to expand into, or (2) By restricting starting of the RCPs to when the secondary water temperature of each Steam Generator is less than 50°F above each of the RCS Cold Leg temperatures. The 50°F limit includes instrument error.

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3/4.4.1 (Continued)

The Technical Specifications for Cold Shutdown allow an inoperable RHR pump to be the operating RHR pump for up to 2 hours for surveillance testing to establish operability. This is required because of the piping arrangement when the RHR system is being used for Decay Heat Removal.

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loops and may also prevent water hammer, pump cavitation, and pumping of non-condensable gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrument drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

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RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

SR 4.4.1.3.4 is modified by a Note that states the SR is not required to be performed until 12 hours after entering MODE 4. In a rapid shutdown, there may be insufficient time to verify all susceptible locations prior to entering MODE 4.

The 31 day frequency for ensuring locations are sufficiently filled with water takes into consideration the gradual nature of gas accumulation in the RHR System piping and the procedural controls governing system operation.

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3/4.4.2 Safety Valves

The Pressurizer Code Safety Valves operate to prevent the RCS from being pressurized above its Safety Limit of 2735 psig. Each safety valve is designed to relieve 313,826 lbs per hour of saturated steam at the valve setpoint. The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that **NO** safety valves are OPERABLE, an RCS vent opening of at least 2.20 square inches will provide overpressure relief capability and will prevent RCS overpressurization. In addition, the Overpressure Mitigating System provides a diverse means of protection against RCS overpressurization at low temperatures.

During operation, all Pressurizer Code Safety Valves must be OPERABLE to prevent the RCS from being pressurized above its Safety Limit of 2735 psig. The combined relief capacity of all of these valves is greater than the maximum surge rate resulting from a complete loss-of-load assuming **NO** Reactor trip until the first Reactor Trip System Trip Setpoint is reached (i.e., **NO** credit is taken for a direct Reactor trip on the loss-of-load) and also assuming **NO** operation of the power-operated relief valves or steam dump valves.

The pressurizer safety valves are set to open at an RCS pressure of 2465 psig +2% and -3% to avoid exceeding the maximum design pressure safety limit and to maintain accident assumptions. The pressurizer safety valve lift setting is needed to assure acceptable results for the Loss of Load/ Turbine Trip analysis. The upper and lower pressure tolerance limits are based on the tolerance requirements assumed in the safety analyses.

In MODE 5 only one Pressurizer Code Safety is required for overpressure protection. In lieu of an actual OPERABLE Code Safety Valve, an unisolated and unsealed vent pathway (i.e., a direct, unimpaired opening, a vent pathway with valves locked open and/or power removed and locked on an open valve) of equivalent size can be taken credit for as synonymous with an OPERABLE Code Safety.

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Demonstration of the safety valves lift settings will occur only during shutdown and will be performed in accordance with the provisions of the ASME OM Code. The Pressurizer Code Safety Valves lift settings allows a +2%, -3% setpoint tolerance for OPERABILITY; however, the valves are reset to within ±1% during the surveillance to allow for drift.

3/4.4.3 Pressurizer

Surveillance Requirement 4.4.3.1 ensures that the maximum water volume parameter is restored to within its limit following expected transient operation. The maximum water volume (1133 cubic feet) ensures that a steam bubble is formed and thus the RCS is **NOT** a hydraulically solid system. The requirement that both backup pressurizer heater groups be OPERABLE enhances the capability of the plant to control Reactor Coolant System pressure and establish natural circulation. The surveillance frequencies are controlled under the Surveillance Frequency Control Program.

3/4.4.4 Relief Valves

The opening of the power-operated relief valves (PORVs) fulfills **NO** safety-related function and **NO** credit is taken for their operation in the safety analysis for MODE 1, 2 or 3. Equipment necessary to establish PORV operability in Modes 1 and 2 is limited to Vital DC power and the Instrument Air system. Equipment necessary to establish block valve operability is limited to an AC power source. Each PORV has a remotely operated block valve to provide a positive shutoff capability should a PORV fail in the open position.

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The OPERABILITY of the PORVs and block valves is determined on the basis of their being capable of performing the following functions:

a. Manual control of PORVs to Control Reactor Coolant System pressure. This is a function that is used as a back-up for the steam generator tube rupture and to support plant shutdown in the event of an Appendix R fire. These functions are considered to be Important-To-Safety, or Quality Related per the FPL Quality Assurance program.

b. Maintaining the integrity of the reactor coolant pressure boundary. This is a function that is related to controlling identified leakage and ensuring the ability to detect unidentified reactor coolant pressure boundary leakage.

c. Manual control of the block valve to: (1) Unblock an isolated PORV to allow it to be used for manual control of reactor coolant system pressure, and (2) Isolate a PORV with excessive leakage.

d. Manual control of a block valve to isolate a stuck-open PORV.

e. Ability to open or close the valves, consistent with the required function of the valves.

The PORVs are also used to provide automatic pressure control in order to reduce the challenges to the RCS code safety valves for overpressurization events. (The PORVs are **NOT** credited in the overpressure accident analyses as noted above.)

Surveillance Requirements provide the assurance that the PORVs and block valves can perform their functions. The Inservice Testing Program is applicable to PORVs and block valves. Specification 4.4.4. also addresses block valves. The block valves are exempt from the surveillance requirements to cycle the valves when they have been closed to comply with the ACTION requirements.

This precludes the need to cycle the valves with full system differential pressure, or when maintenance is being performed to restore an inoperable PORV to OPERABLE status.

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ACTION statement a. includes the requirement to maintain power to closed block valves because removal of power would render block valves inoperable, with respect to their ability to be reopened in a timely manner to support decay heat removal or depressurization through the PORVs, and the requirements of ACTION statement c. would apply. Power is maintained to the block valves so that it is operable and may be opened subsequently to allow use of the PORV for reactor pressure control or decay heat removal by using feed and bleed. Closure of the block valves establishes reactor coolant pressure boundary integrity in the case of a PORV with excess leakage or for bonnet or stem leakage on the PORV or block valve which is isolable. (Reactor coolant pressure boundary integrity takes priority over the capability of the PORV to mitigate an overpressure event.) However, the APPLICABILITY requirements of the Limiting Condition for Operation (LCO) to operate with the block valves closed with power maintained to the block valves are intended only 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 to eliminate the leakage condition.

ACTION statements b. and c. include removal of power from a closed block valve as additional assurance against inadvertent opening of the block valve at a time in which the PORV is inoperable for causes other than excessive seat leakage. (In contrast, ACTION statement a. is intended to permit continued plant operation for a limited period with the block valves closed, i.e., continued operation is **NOT** dependent on maintenance at power to eliminate excessive PORV leakage. Therefore, ACTION statement a. does **NOT** require removal of power from the block valve.)

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ACTION statement d. establishes remedial measures consistent with the function of block valves. The most important reason 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 remedial action is to place the PORV in manual control to preclude its automatic opening for an overpressure event, and thus avoid the potential for a stuck-open PORV at a time when the block valve is inoperable. The time allowed to restore the block valves to operable status is based upon the remedial action time limits for inoperable PORVs per ACTION statements b. and c. These actions are also consistent with the use of the PORVs to control reactor coolant system pressure if the block valves are inoperable at a time when they have been closed to isolate PORVs with excessive leakage.

Leakage sufficient to cause the RCS total IDENTIFIED LEAKAGE to exceed 10 GPM is excessive, rendering the affected PORV inoperable. With PORV leakage identified, but small enough that it does **NOT** cause RCS total IDENTIFIED LEAKAGE to exceed 10 GPM, the PORV is **NOT** inoperable because of excessive leakage. The PORV may still be isolated as a matter of prudence but this is an operational decision, **NOT** a regulatory requirement. Closing the block valve does **NOT** render either the block valve or the PORV inoperable. The block valve is already performing its intended function. The PORV is still capable of relieving RCS pressure. This function is used as a backup for the steam Generator Tube Rupture, and to support plant shutdown in the event of an Appendix R fire.

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Surveillance Requirement 4.4.4 states that the block valve surveillance is **NOT** required if the block valve is closed to provide an isolation function. This exemption only applies when the block valve has been closed to comply with the ACTION requirements. If the PORV is declared inoperable due to excessive leakage, then the block valve must be closed to comply with ACTION a. Block valve surveillance is **NOT** required. If the PORV has **NOT** been declared inoperable, but the block valve has been closed as a matter of prudence, then the block valve has **NOT** been closed to comply with an ACTION requirement, and the surveillance must still be performed.

3/4.4.5 Steam Generator - (SG) Tube Integrity

Background

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. SG tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.1.1, Reactor Coolant Loops and Coolant Circulation - Startup and Power Operation, LCO 3.4.1.2, Hot Standby, LCO 3.4.1.3, Hot Shutdown, LCO 3.4.1.4.1, Cold Shutdown Loops Filled, and LCO 3.4.1.4.2, Cold Shutdown - Loops **NOT** Filled.

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

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SG tubing is subject to a variety of degradation mechanisms. SG tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are **NOT** managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 6.8.4.j, Steam Generator (SG) Program, requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 6.8.4.j, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational leakage. The SG performance criteria are described in Specification 6.8.4.j. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

Applicable Safety Analysis

The Steam Generator Tube Rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding a SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary-to-secondary leakage rate equal to 0.20 gpm at room temperature conditions for each of the two intact SGs plus the leakage rate associated with a double-ended rupture of a single tube in the third (ruptured) SG. The accident analysis for a SGTR assumes the contaminated secondary fluid is released to the atmosphere initially via the Condenser Steam Jet Air Ejectors (SJAE) then via the Main Steam Safety Valves and/or the Main Steam Atmospheric Dump Valves.

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The analysis for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed **NOT** to rupture). In the dose consequence analysis for these events the activity level in the steam discharged to the atmosphere is based on a Primary-To-Secondary Leakage Rate of 0.60 gpm total through all SGs and 0.20 gpm through any one SG at room temperature conditions, or is assumed to increase to these levels as a result of accident induced conditions. For accidents that do **NOT** involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.8, Reactor Coolant System Specific Activity, limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 2), 10 CFR 50.67 (Ref. 7) or the NRC approved licensing basis.

Steam Generator Tube Integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

Limiting Condition for Operation (LCO)

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the plugging criteria be plugged in accordance with the Steam Generator Program.

During a SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. If a tube was determined to satisfy the plugging criteria but was **NOT** plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall from 18.11 inches below the top of the tubesheet on the hot leg side to 18.11 inches below the top of the tubesheet on the cold leg side. The tube-to-tubesheet weld is **NOT** considered part of the tube.

A SG tube has integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 6.8.4.j and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

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There are three SG performance criteria: structural integrity, accident induced leakage, and operational leakage. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, the gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation. Tube collapse is defined as, for the load displacement curve for a given structure, collapse occurs at the top of the load verses displacement curve where the slope of the curve becomes zero. The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term significant is defined as an accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse to be established. For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube **NOT** exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

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The accident induced leakage performance criterion ensures that the primary-to-secondary leakage caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analyses assume that accident leakage does **NOT** exceed 0.60 gpm total through all SGs and 0.20 gpm through any one of the three SGs at room temperature conditions. The accident induced leakage rate includes any primary to secondary leakage existing prior to the accident in addition to primary to secondary leakage induced during the accident.

The operational leakage performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational leakage is contained in LOC 3.4.6.2 and limits primary-to-secondary leakage through any one SG to 150 gpd at room temperature. This limit is based on the assumption that a single crack leaking this amount would **NOT** propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of leakage is due to more than one crack, the cracks are very small, and the above assumption is conservative.

Applicability

SG tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

Reactor Coolant System conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary-to-secondary differential pressure is low, resulting in lower stresses and reduced potential for leakage.

Actions

The ACTIONS are modified by a Note clarifying that the ACTIONS may be entered independently for each SG tube. This is acceptable because the ACTIONS provide appropriate compensatory actions for each affected SG tube. Complying with the ACTIONS may allow for continued operation, and any additional affected SG tubes are governed by subsequent ACTION entry and application.

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Action a.1 & a.2

ACTIONS a.1 and a.2 apply if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube plugging criteria but were **NOT** plugged in accordance with the Steam Generator Program as required by Surveillance Requirement (SR) 4.4.5.2. An evaluation of SG tube integrity of the affected tubes must be made. SG tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG plugging criteria limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is **NOT** being maintained, ACTION b applies.

An allowable outage time of seven days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may **NOT** have tube integrity.

If the evaluation determines that the affected tubes have tube integrity, ACTION a.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tubes must be plugged prior to entering MODE 4 following the next refueling outage or SG inspection. This allowable outage time is acceptable since operation until the next inspection is supported by the operational assessment.

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Action b.

If the requirements and associated allowable outage time of ACTION a are **NOT** met or if SG tube integrity is **NOT** being maintained, the reactor must be brought to HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours. The allowable outage times are reasonable, based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Surveillance Requirements

SR 4.4.5.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the As Found condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube plugging criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, non-destructive examination (NDE) technique capabilities, and inspection locations.

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The Steam Generator Program defines the frequency of SR 4.4.5.1. The frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 6.8.4.j contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections. If crack indications are found in any SG tube, the maximum inspection interval for all affected and potentially affected SGs is restricted by Specification 6.8.4.j until subsequent inspections support extending the inspection interval.

SR 4.4.5.2

During a SG inspection any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. The tube plugging criteria delineated in Specification 6.8.4.j are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement for future flaw growth. In addition, the tube plugging criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tubes. Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

The frequency of prior to entering HOT SHUTDOWN following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the plugging criteria are plugged prior to subjecting the SG tubes to significant primary-to-secondary pressure differential.

References

1. NEI 97-06, Steam Generator Program Guidelines

2. 10 CFR 50 Appendix A, GDC 19

3. **NOT** Used

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3/4.4.5 (Continued)

4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB

5. Draft Regulatory Guide 1.121, Bases for Plugging Degraded PWR Steam Generator Tubes, August 1976

6. EPRI Pressurized Water Reactor Steam Generator Examination Guidelines

7. 10 CFR 50.67, Accident Source Term

3/4.4.6 Reactor Coolant System Leakage

3/4.4.6.1 Leakage Detection Systems

The RCS Leakage Detection Systems required by this specification are provided to monitor and detect leakage from the reactor coolant pressure boundary to the containment. The containment sump level system is the normal sump level instrumentation. The Post Accident Containment Water Level Monitor - Narrow range instrumentation also functions as a sump level monitoring system. In addition, gross leakage will be detected by changes in makeup water requirements, visual inspection, and audible detection. Leakage to other systems will be detected by activity changes (e.g., within the component cooling system) or water inventory changes (e.g., tank levels).

In Modes 1-4, with both the Particulate and Gaseous Radioactivity Monitoring Systems inoperable, the isolation valves in the Containment Purge Supply and Exhaust and Instrument Air Bleed flow paths are required to be maintained closed in order to allow continued operation for up to 7 days. A note permits the instrument air flow path to be opened under administrative control in order to maintain the containment internal pressure within specified limits since it is relatively small in size and easily isolated either automatically by a safety injection signal or manually by the operator monitoring containment conditions while the valves are open.

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3/4.4.6.1 (Continued)

Background

Components that contain or transport the coolant to or from the reactor core make up the Reactor Coolant System (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 system operation in the presence of leakage from these sources to amounts that do **NOT** compromise safety. This LCO specifies the types and amounts of leakage.

3/4.4.6.2 Operational Leakage

10 CFR 50, Appendix A, GDC (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant leakage. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

The safety significance of RCS leakage varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant 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 facility and the public.

A limited amount of leakage inside containment is expected from auxiliary systems 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 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).

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3/4.4.6.2 (Continued)

Applicable Safety Analyses

The primary-to-secondary leakage safety analysis assumption for individual events varies. The assumption varies depending on whether the primary-to-secondary leakage from a single steam generator (SG) can adversely affect the dose consequences for the event. In which case, the affected SG is assumed to have the maximum allowable leakage (0.20 gpm at room temperature). Collectively, however, the safety analyses for events resulting in steam discharge to the atmosphere assume that primary-to-secondary leakage from all Steam Generators (SGs) is 0.60 gpm total and 0.20 gpm at room temperature conditions through any one SG. The LCO requirement to limit primary-to-secondary leakage through any one SG to less than or equal to 150 gpd at room temperature is significantly less than the conditions assumed in the safety analysis.

For Control Room doses, primary-to-secondary leakage is a factor in the dose releases outside containment resulting from a RCCA Ejection accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a SG tube rupture (SGTR). The leakage contaminates the secondary fluid.

The UFSAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is released to the atmosphere initially via the condenser SJAE and then via Atmospheric Dump Valves and/or Main Steam Safety Valves for a limited period of time. Operator action is taken to isolate the affected SG within the time period. Accidents for which the radiation dose release path is primary-to-secondary leakage, the RCCA Ejection accident is more limiting for site radiation dose releases. The safety analysis for the RCCA Ejection accident assumes that primary-to-secondary leakage from all SGs is 0.60 gpm total. The dose consequences resulting from the RCCA Ejection Accident are well within the limits defined in 10 CFR 50.67.

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3/4.4.6.2 (Continued)

The RCS operational leakage satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

Limiting Condition for Operation (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.

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 UNIDENTIFIED LEAKAGE and is well within the capability of the RCS Makeup System. IDENTIFIED LEAKAGE includes leakage to the containment from specifically known and located sources, but does **NOT** include PRESSURE BOUNDARY LEAKAGE or controlled reactor coolant pump seal leak-off (a normal function **NOT** considered leakage). Violation of this LCO could result in continued degradation of a component or system.

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d. Primary-to-Secondary Leakage Through Any One SG

The limit of 150 gpd per SG at room temperature is based on the Operational Leakage Performance Criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 4). The Steam Generator Program Operational Leakage Performance Criterion in NEI 97-06 states, the RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day. The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of SG tube ruptures.

e. RCS Pressure Isolation Valve Leakage

RCS pressure isolation valve 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.

The specified leakage limits for the RCS pressure isolation valves are sufficiently low to ensure early detection of possible in-series check valve failure.

Applicability

In MODES 1, 2, 3, and 4, the potential for reactor coolant PRESSURE BOUNDARY LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, leakage limits are **NOT** required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for leakage.

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3/4.4.6.2 (Continued)

ACTIONS

Action a.

If any PRESSURE BOUNDARY LEAKAGE exists, or primary to secondary leakage is **NOT** within limit, the reactor must be brought to lower pressure conditions to reduce the severity of the leakage and its potential consequences. It should be noted that Leakage past seals and gaskets is **NOT** PRESSURE BOUNDARY LEAKAGE. The reactor must be brought to HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours. This ACTION reduces the leakage and also reduces the factors that tend to degrade the pressure boundary.

Action b.

UNIDENTIFIED LEAKAGE or IDENTIFIED LEAKAGE in excess of the LCO limits must be reduced to within the limits within 4 hours. This allowable outage 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.

Action c.

The leakage from any RCS Pressure Isolation Valve is sufficiently low to ensure early detection of possible in-series valve failure. It is apparent that when pressure isolation is provided by two in-series valves and when failure of one valve in the pair can go undetected for a substantial length of time, verification of valve integrity is required. With one or more RCS Pressure Isolation Valves with leakage greater than that allowed by Specification 3.4.6.2.e, within 4 hours, at least two valves in each high pressure line having a non-functional valve must be closed and remain closed to isolate the affected lines. In addition, the ACTION statement for the affected system must be followed and the leakage from the remaining pressure isolation valves in each high pressure line having a valve **NOT** meeting the criteria of Table 3.4-1 shall be recorded daily. If these requirements are **NOT** met, the reactor must be brought to at least HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours.

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Action d.

With one or more RCS Pressure Isolation Valves with leakage greater than 5 gpm, the leakage must be reduced to below 5 gpm within 1 hour or the reactor must be brought to at least HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours.

The allowable outage 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 4.4.6.2.1

Verifying Reactor Coolant System leakage to be within the LCO limits ensures the integrity of the Reactor Coolant Pressure Boundary is maintained. PRESSURE BOUNDARY LEAKAGE would at first appear as UNIDENTIFIED LEAKAGE and can only be positively identified by inspection. It should be noted that leakage past seals and gaskets is **NOT** PRESSURE BOUNDARY LEAKAGE. UNIDENTIFIED LEAKAGE and IDENTIFIED LEAKAGE are determined by performance of a Reactor Coolant System water inventory balance.

a. & b.

These SRs demonstrate that the RCS operational leakage is within the LCO limits by monitoring the containment atmosphere gaseous or particulate radioactivity monitor and the containment sump level in accordance with the Surveillance Frequency Control Program.

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3/4.4.6.2 (Continued)

c.

The RCS water inventory balance must be performed with the reactor at steady state operating conditions and near operating pressure. The Surveillance is modified by two notes. Note *** states that this SR is **NOT** required to be performed until 12 hours after establishment of steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Steady state operations is required to perform a proper inventory balance since calculations during maneuvering are **NOT** useful. For RCS operational leakage determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, Pressurizer and makeup tank levels, makeup and letdown, and Reactor Coolant Pump seal injection and return flows.

An early warning of PRESSURE BOUNDARY LEAKAGE or UNIDENTIFIED LEAKAGE is provided by the automatic systems that monitor containment atmosphere radioactivity, containment normal sump inventory and discharge, and reactor head flange leak-off. It should be noted that leakage past seals and gaskets is **NOT** PRESSURE BOUNDARY LEAKAGE. These leakage detection systems are specified in LCO 3.4.6.1, Reactor Coolant System Leakage Detection Systems.

Note ** states that this SR is **NOT** applicable to primary-to-secondary leakage because leakage of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

The frequency is a reasonable interval to trend leakage and recognizes the importance of early leakage detection in the prevention of accidents. The surveillance frequency is controlled under the Surveillance Frequency Control Program.

d.

This SR demonstrates that the RCS Operational Leakage is within the LCO limits by monitoring the Reactor Head Flange Leak-off System in accordance with the Surveillance Frequency Control Program.

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3/4.4.6.2 (Continued)

e.

This SR verifies that primary-to-secondary leakage is less than or equal to 150 gpd through any one SG. Satisfying the primary-to-secondary leakage limit ensure that the operational leakage performance criterion in the Steam Generator Program is met. If this SR is **NOT** met, compliance with LCO 3.4.5, Steam Generator (SG) Tube Integrity, should be evaluated. The 150-gpd limit is measured at room temperature as described in Reference 5. The operational leakage rate limit applies to leakage through any one SG. If it is **NOT** practical to assign the leakage to an individual SG, all the primary to secondary leakage should be conservatively assumed to be from one SG.

The SR is modified by Note ***, which states that the Surveillance is **NOT** required to be performed until 12 hours after establishment of steady state operation. For RCS primary to-secondary leakage determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and reactor coolant pump seal injection and return flows.

The surveillance frequency, controlled under the Surveillance Frequency Control Program, trends primary to secondary leakage and recognizes the importance of early leakage detection in the prevention of accidents. The primary-to-secondary leakage is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 5).

SR 4.4.6.2.2

It is apparent that when pressure isolation is provided by two in-series check valves and when failure of one valve in the pair can go undetected for a substantial length of time, verification of valve integrity is required. Since these valves are important in preventing overpressurization and rupture of the ECCS low pressure piping, which could result in a LOCA that bypasses containment, these valves should be tested periodically to ensure low probability of gross failure.

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3/4.4.6.2 (Continued)

This SR verifies RCS Pressure Isolation Valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valve is IDENTIFIED LEAKAGE and will be considered as a portion of the allowed limit.

References

1. 10 CFR 50, Appendix A, GDC 30
2. Regulatory Guide 1.45, May 1973
3. UFSAR, Section 14.2.4.1
4. NEI 97-06, Steam Generator Program Guidelines
5. EPRI PWR Primary-to-Secondary Leak Guidelines

3/4.4.7 Deleted

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3/4.4.8 Specific Activity

The maximum dose that an individual at the Exclusion Area Boundary can receive for 2 hours following an accident, or at the Low Population Zone Outer Boundary for the radiological release duration, is specified in 10 CFR 50.67. Doses to Control Room operators must be limited per GDC 19. The limits on specific activity ensure that the offsite and Control Room doses are appropriately limited 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 dose consequences in the event of a Steam Line Break (SLB), Steam Generator Tube Rupture (SGTR), Rod Cluster Control Assembly (RCCA) Ejection, or Locked Rotor Accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133. The allowable levels are intended to ensure that offsite and Control Room doses meet the appropriate SRP acceptance criteria.

The safety analyses assume the specific activity of the reactor coolant is at the LCO limits, and an existing reactor coolant steam generator (SG) tube leakage rate of 0.20 gpm at room temperature exists. The safety analyses assume the specific activity of the secondary coolant is at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.1.4, "Specific Activity."

The SLB and SGTR safety analyses consider two cases of reactor coolant iodine specific activity. One case assumes specific activity at 0.25 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the rate of release of iodine from the fuel rods containing cladding defects to the primary coolant immediately after a SLB (by a factor of 500), or SGTR (by a factor of 335), respectively. The second case assumes the initial reactor coolant iodine activity at 60.0 μCi/gm DOSE EQUIVALENT I-131 due to an iodine spike caused by a reactor or an RCS transient prior to the accident. In both cases, the noble gas specific activity is assumed to be 447.7 μCi/gm DOSE EQUIVALENT XE-133.

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The RCS Specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

The iodine specific activity in the reactor coolant is limited to 0.25 µCi/gm DOSE EQUIVALENT I-131, and the noble gas specific activity in the reactor coolant is limited to 447.7 µCi/gm DOSE EQUIVALENT XE-133. The limits on specific activity ensure that the offsite and Control Room doses will meet the appropriate SRP acceptance criteria.

The SLB, SGTR, Locked Rotor, and RCCA Ejection Accident analyses show that the calculated doses are within limits. Violation of the LCO may result in reactor coolant activity levels that could, in the event of any one of these accidents, lead to doses that exceed the acceptance criteria.

The ACTIONS permit limited operation when DOSE EQUIVALENT I-131 is greater than 0.25 µCi/gm and less than 60 µCi/gm. The Actions require sampling within 4 hours and every 4 hours following to establish a trend.

One surveillance requires performing a gamma isotropic analysis as a measure of noble gas specific activity of the reactor coolant in accordance with the Surveillance Frequency Control Program. 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 the noble gas specific activity.

A second surveillance is performed to ensure that iodine specific activity remains within the LCO limit in accordance with the Surveillance Frequency Control Program during normal operation and following fast power changes when iodine spiking is more apt to occur. The frequency between 2 and 6 hours after a power change of greater than 15% RATED THERMAL POWER within a 1 hour period, is established because the iodine levels peak during this time following iodine spike initiation.

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3/4.4.9 Pressure/Temperature Limits

All components in the RCS are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are induced by normal load transients, reactor trips, and startup and shutdown operations. During RCS heatup and cooldown, the temperature and pressure changes must be limited to be consistent with design assumptions and to satisfy stress limits for brittle fracture.

During heatup, the thermal gradients through the reactor vessel wall produce thermal stresses which are compressive at the reactor vessel inside surface and which are tensile at the reactor vessel outside surface. Since reactor vessel internal pressure always produces tensile stresses at both the inside and outside surface locations, the total applied stress is greatest at the outside surface location. However, since neutron irradiation damage is larger at the inside surface location when compared to the outside surface, the inside surface flaw may be more limiting. Consequently for the heatup analysis both the inside and outside surface flaw locations must be analyzed for the specific pressure and thermal loadings to determine which is more limiting.

During cooldown, the thermal gradients through the reactor vessel wall produce thermal stresses which are tensile at the reactor vessel inside surface and which are compressive at the reactor vessel outside surface. Since reactor vessel internal pressure always produces tensile stresses at both the inside and outside surface locations, the total applied stress is greatest at the inside surface location. Since the neutron irradiation damage is also greatest at the inside surface location, the inside surface flaw is the limiting location. Consequently, only the inside surface flaw must be evaluated for the cooldown analysis.

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The temperature and pressure changes during heatup and cooldown are limited to be consistent with the requirements given in the 1995 Edition through 1996 Addenda of the ASME Boiler and Pressure Vessel Code, Section XI, Appendix G:

1. The reactor coolant temperature and pressure and system heatup and cooldown rates (with the exception of the pressurizer) shall be limited in accordance with Figures 3.4-2 and 3.4-3 in the Technical Specifications for the service period specified thereon:

   a. Allowable combinations of pressure and temperature for specific temperature change rates are below and to the right of the limit lines shown. Limit lines for cooldown rates between those presented may be obtained by interpolation; and

   b. Figures 3.4-2 and 3.4-3 in the Technical Specifications define limits to assure prevention of non-ductile failure only. For normal operation, other inherent plant characteristics, e.g., pump heat addition and pressurizer heater capacity, may limit the heatup and cooldown rates that can be achieved over certain pressure temperature ranges.

2. These limit lines shall be calculated periodically using methods provided below.

3. The secondary side of the Steam Generator must **NOT** be pressurized above 200 psig if the temperature of the Steam Generator is below 70°F.

4. The Pressurizer heatup and cooldown rates shall **NOT** exceed 100°F/h and 200°F/h, respectively. The spray shall **NOT** be used if the temperature difference between the Pressurizer and the spray fluid is greater than 320°F, and

5. System preservice hydrotests and inservice leak and hydrotests shall be performed at pressures in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section XI.

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3/4.4.9 (Continued)

The fracture toughness properties of the ferritic materials in the reactor vessel are determined in accordance with the NRC Standard Review Plan, the version of the ASTM E185 standard required by 10 CFR 50, Appendix H, and in accordance with additional reactor vessel requirements. Topical Report BAW-2308, Revision 2-A is the source for the initial weld materials properties for Linde 80 welds. The NRC approved the FPL exemption request (L-2009-023) to use Topical Report BAW-2308, Revisions 1 and 2-A in a letter dated March 11, 2010.

The properties are then evaluated in accordance with Appendix G of the 1995 Edition through 1996 Addenda of Section XI of the ASME Boiler and Pressure Vessel Code and the additional requirements of 10 CFR 50, Appendix G and the calculation methods described in Westinghouse Report WCAP-14040-NP-A, Revision 2, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Curves" with consideration of ASME Code Case N-588.

Heatup and cooldown limit curves are calculated using the most limiting value of the nil-ductility reference temperature, RT_{NDT}, at the end of 48 effective full power years (EFPY) of service life. The 48 EFPY service life period is chosen such that the limiting RT_{NDT}, at the 1/4T location in the core region is greater than the RT_{NDT}, of the limiting unirradiated material. The selection of such a limiting RT_{NDT} assures that all components in the Reactor Coolant System will be operated conservatively in accordance with applicable Code requirements.

The heatup and cooldown limit curves, Figures 3.4-2 and 3.4-3 in the Technical Specifications are composite curves prepared by determining the most conservative case with either the inside or outside wall controlling, for heatup rates of 60 and 100 degrees F per hour and cooldown rates of 0, 20, 40, 60, and 100 degrees F per hour. The heatup and cooldown curves were prepared based upon the most limiting value of predicted adjusted reference temperature at the end of the applicable service period (48 EFPY).

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3/4.4.9 (Continued)

The reactor vessel materials have been tested to determine their initial RT_{NDT}; the results of these tests are shown in Table B 3/4.4-1. Reactor operation and resultant fast neutron (E greater than 1 MeV) irradiation can cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the fluence and chemistry factors of the material has been predicted using Regulatory Guide 1.99, Revision 2, dated May 1988, Radiation Embrittlement of Reactor Vessel Materials. The heatup and cooldown limit curves of Figures 3.4-2 and 3.4-3 in the Technical Specifications include predicted adjustments for this shift in RT_{NDT} at the end of the applicable service period.

The actual shifts in RT_{NDT}, of the vessel materials will be established periodically during operation by removing and evaluating, in accordance with the version of the ASTM E185 standard required by 10 CFR Appendix H, reactor vessel material irradiation surveillance specimens installed near the inside wall of the reactor vessel in the core area. Since the neutron spectra at the irradiation samples and vessel inside radius are essentially identical, the measured transition shift for a sample can be applied with confidence to the adjacent section of the reactor vessel.

Since the limiting circumferential weld beltline material in Unit 3 is identical to the limiting circumferential weld beltline material in Unit 4 (Intermediate to Lower Shell Circumferential Weld), the RV surveillance program was integrated, and the results from capsule testing is applied to both Units. The surveillance capsule results were considered with the methodology in Regulatory Guide 1.99, Revision 2, to determine material properties information for generating the heatup and cooldown curves in Figures 3.4-2 and 3.4-3 in the Technical Specifications. The integrated surveillance program along with similar identical reactor vessel design and operating characteristics allows the same heatup and cooldown limit curves to be applicable at both Unit 3 and Unit 4.

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TABLE B 3/4.4-1
REACTOR VESSEL TOUGHNESS (UNIT 3)

Component	Material Type	Cu (%)	Ni (%)	P (%)	NDTT (°F)	50 ft lb/35 mils Lateral Expansion Temp (°F)		RT_{NDT} (°F)	Minimum Upper Shelf (ft lb)	
						Long	Trans		Long	Trans
Cl. Hd. Mono Forging	A508 Cl. 3	0.06	0.87	0.005	-50	-	-	-50	-	142
Ves. Sh. Flange	A508 Cl. 2	-	0.65	0.010	-23[a]	-	-41[a]	-23[a]	>120	>78[a]
Inlet Nozzle 1	A508 Cl. 2	0.16[b]	0.76	0.019	60[a]	-	NA	60	NA	109[c][d]
Inlet Nozzle 2	A508 Cl. 2	0.16[b]	0.74	0.019	60[a]	-	NA	60	NA	109[c][d]
Inlet Nozzle 3	A508 Cl. 2	0.16[b]	0.80	0.019	60[a]	-	NA	60	NA	109[c][d]
Outlet Nozzle 1	A508 Cl. 2	0.16[b]	0.79	0.010	27[a]	-	9[a]	27	>110	>71.5[a]
Outlet Nozzle 2	A508 Cl. 2	0.16[b]	0.72	0.010	7[a]	-	-22[a]	7	>111	>72[a]
Outlet Nozzle 3	A508 Cl. 2	0.16[b]	0.72	0.010	42[a]	-	23[a]	42	>140	>91[a]
Upper Shell	A508 Cl. 2	0.11[c]	0.68[c]	0.010	50	-	44[a]	50	-	99
Inter. Shell	A508 Cl. 2	0.06[c]	0.70[c]	0.010	40	-	25[a]	40	-	93
Lower Shell	A508 Cl. 2	0.08[c]	0.67[c]	0.010	30	-	2[a]	30	-	100
Trans. Ring	A508 Cl. 2	-	0.69	0.013	60[a]	-	58[a]	60	>109	>70.5[a]
Bot. Hd. Dome	A302 Gr. B	-	-	0.010	-10	-	NA	30	NA	NA
Upper to Inter. Shell Girth Weld	LINDE 80	0.26[c]	0.60[c]	-	-	-	-	-33.2[e]	NA	70[c]
Inter. to Lower Shell Girth Weld	LINDE 80	0.23[c]	0.59[c]	0.011	-	-	63	-53.5[e]	-	65

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TABLE B 3/4.4-1
REACTOR VESSEL TOUGHNESS (UNIT 3)

Component	Material Type	Cu (%)	Ni (%)	P (%)	NDTT (°F)	50 ft lb/35 mils Lateral Expansion Temp (°F)		RT_{NDT} (°F)	Minimum Upper Shelf (ft lb)	
						Long	Trans		Long	Trans
HAZ	HAZ	-	-	-	0[a]	-	0	0	-	168
Inlet/Outlet Nozzle Weld[f]	LINDE 80	0.34	0.68	-	-	-	-	-74.3(e)	-	-
Inlet/Outlet Nozzle Weld[f]	LINDE 80	0.16	0.57	-	-	-	-	-48.6(e)	-	-
Inlet/Outlet Nozzle Weld[f]	LINDE 80	0.19	0.57	-	-	-	-	-48.6(e)	-	-

(a) Estimated values based on NUREG-0800, Branch Technical Position - MTEB 52
(b) Conservative values based on Oak Ridge National Laboratory document ORNL/TM-2006/530
(c) BAW-2313, Revision 6, AREVA NP Document No. 77-2313-006, November 2008
(d) Generic Value
(e) BAW-2308, Revision 2-A
(f) It is unknown which weld was fabricated from which weld wire material.

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TABLE B 3/4.4-2
REACTOR VESSEL TOUGHNESS (UNIT 4)

Component	Material Type	Cu (%)	Ni (%)	P (%)	NDTT (°F)	50 ft lb/35 mils Lateral Expansion Temp (°F)		RT_{NDT} (°F)	Minimum Upper Shelf (ft lb)	
						Long	Trans		Long	Trans
Cl. Hd. Mono Forging	A508 Cl. 3	0.06	0.86	0.004	-60	-	-	-60	-	143
Ves. Sh. Flange	A508 Cl. 2	-	0.68	0.010	-1[a]	-	-11[a]	-1	176	114[a]
Inlet Nozzle 1	A508 Cl. 2	0.08	0.71	0.009	60[a]	-	NA	60	NA	109[c][e]
Inlet Nozzle 2	A508 Cl. 2	0.16[b]	0.84	0.019	60[a]	-	NA	60	NA	109[c][e]
Inlet Nozzle 3	A508 Cl. 2	0.16[b]	0.75	0.008	16[a]	-	13[a]	16	162	105[a]
Outlet Nozzle 1	A508 Cl. 2	0.16[b]	0.78	0.010	7[a]	-	-25[a]	7	165	107[a]
Outlet Nozzle 2	A508 Cl. 2	0.16[b]	0.68	0.010	38[a]	-	16[a]	38	160	104[a]
Outlet Nozzle 3	A508 Cl. 2	0.16[b]	0.70	0.010	60[a]	-	42[a]	60	143	93[a]
Upper Shell	A508 Cl. 2	0.11[c]	0.70[c]	0.010[c]	40[c]	-	32[a]	40	-	103
Inter. Shell	A508 Cl. 2	0.05[c]	0.68[c]	0.010[c]	50[c]	-	90[a]	50	-	88
Lower Shell	A508 Cl. 2	0.06[c]	0.74[c]	0.010[c]	40[c]	-	38[a]	40	-	86
Trans. Ring	A508 Cl. 2	-	0.69	0.011	60[a]	-	30[a]	60	NA	NA
Bot. Hd. Dome	A302 Gr. B	-	-	0.010	10	-	30[a]	10	NA	NA
Upper to Inter. Shell Girth Weld (Inner 67%)	LINDE 80	0.26[c]	0.60[c]	-	-	-	-	-33.2[f]	NA	72[d]

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TABLE B 3/4.4-2
REACTOR VESSEL TOUGHNESS (UNIT 4)

Component	Material Type	Cu (%)	Ni (%)	P (%)	NDTT (°F)	50 ft lb/35 mils Lateral Expansion Temp (°F)		RT_{NDT} (°F)	Minimum Upper Shelf (ft lb)	
						Long	Trans		Long	Trans
Upper to Inter. Shell Girth Weld (Outer 33%)	LINDE 80	0.32[c]	0.58[c]	-	-	-	-	-31.1[f]	NA	NA
Inter. to Lower Shell Girth Weld	LINDE 80	0.23[c]	0.59[c]	0.011	-	-	63	-53.5[f]	-	65
HAZ	HAZ	-	-	-	0[a]	-	NA	0	NA	140
Inlet/Outlet Nozzle Weld[g]	LINDE 80	0.34	0.68	-	-	-	-	-74.3[f]	-	-
Inlet/Outlet Nozzle Weld[g]	LINDE 80	0.16	0.57	-	-	-	-	-48.6[f]	-	-
Inlet/Outlet Nozzle Weld[g]	LINDE 80	0.19	0.57	-	-	-	-	-48.6[f]	-	-

(a) Estimated values based on NUREG-0800, Branch Technical Position - MTEB 52
(b) Conservative values based on Oak Ridge National Laboratory document ORNL/TM-2006/530
(c) BAW-2313, Revision 6, AREVA NP Document No. 77-2313-006, November 2008
(d) Value based on BAW-1910P, B&W Document No. 77-1164769-00, August 1986
(e) Generic Value
(f) BAW-2308, Revision 2-A
(g) It is unknown which weld was fabricated from which weld wire material.

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Allowable pressure-temperature relationships for various heatup and cooldown rates are calculated using methods derived from Appendix G in Section XI of the 1995 Edition through 1996 Addenda of the ASME Boiler and Pressure Vessel Code as required by Appendix G to 10 CFR Part 50 and Westinghouse Report WCAP-14040-NP-A, Revision 2, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves" with consideration of ASME Code Case N-588.

The general method for calculating heatup and cooldown limit curves is based upon the principles of the linear elastic fracture mechanics (LEFM) technology. In the calculation procedures a semi-elliptical surface defect with a depth of one-quarter of the wall thickness, T, and a length of 3/2T is assumed to exist at the inside of the vessel wall as well as at the outside of the vessel wall. The dimensions of this postulated crack, referred to in Appendix G of the 1995 Edition through 1996 Addenda of ASME Section XI as the reference flaw, amply exceed the current capabilities of inservice inspection techniques. Therefore, the reactor operation limit curves developed for this reference crack are conservative and provide sufficient safety margins for protection against nonductile failure. To assure that the radiation embrittlement effects are accounted for in the calculation of the limit curves, the most limiting value of the nil-ductility reference temperature, RT_{NDT}, is used and this includes the radiation-induced shift, ΔRT_{NDT}, corresponding to the end of the period for which heatup and cooldown curves are generated.

The ASME approach for calculating the allowable limit curves for various heatup and cooldown rates specifies that the total stress intensity factor, K_I, for the combined thermal and pressure stresses at any time during heatup or cooldown cannot be greater than the reference stress intensity factor, K_{Ia}, for the metal temperature at that time. K_{Ia} is obtained from the reference fracture toughness curve, defined in Appendix G to the ASME Code. The K_{Ia} curve is given by the equation:

$$K_{Ia} = 26.78 + 1.223 \exp [0.0145(T-RT_{NDT} + 160)] \quad (1)$$

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Where: K_{Ia} is the reference stress intensity factor as a function of the metal temperature T and the metal nil-ductility reference temperature RT_{NDT}. Thus, the governing equation for the heatup-cooldown analysis is defined in Appendix G of the ASME Code as follows:

$$C\,K_{IM} + K_{IT} < K_{Ia} \qquad (2)$$

Where: K_{IM} = the stress intensity factor caused by membrane (pressure) stress,

K_{IT} = the stress intensity factor caused by the thermal gradients,

K_{Ia} = constant provided by the Code as a function of temperature relative to the RT_{NDT} of the material,

C = 2.0 for level A and B service limits, and

C = 1.5 for inservice hydrostatic and leak test operations.

At any time during the heatup or cooldown transient, K_{Ia} is determined by the metal temperature at the tip of the postulated flaw, the appropriate value for RT_{NDT}, and the reference fracture toughness curve. The thermal stresses resulting from temperature gradients through the vessel wall are calculated and then the corresponding thermal stress intensity factor, K_{IT}, for the reference flaw is computed. From Equation (2) the pressure stress intensity factors are obtained and, from these, the allowable pressures are calculated.

Cooldown

For the calculation of the allowable pressure versus coolant temperature during cooldown, the Code Reference Flaw is assumed to exist at the inside of the vessel wall. During cooldown, the controlling location of the flaw is always at the inside of the wall because the thermal gradients produce tensile stresses at the inside, which increase with increasing cooldown rates. Allowable pressure-temperature relations are generated for both steady state and finite cooldown rate situations. From these relations, composite limit curves are constructed for each cooldown rate of interest.

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The use of the composite curve in the cooldown analysis is necessary because control of the cooldown procedure is based on measurement of reactor coolant temperature, whereas the limiting pressure is actually dependent on the material temperature at the tip of the assumed flaw. During cooldown, the 1/4T vessel location is at a higher temperature than the fluid adjacent to the vessel ID. This condition, of course, is **NOT** true for the steady-state situation. It follows that at any given reactor coolant temperature, the ΔT developed during cooldown results in a higher value of K_{Ia} at the 1/4T location for finite cooldown rates than for steady-state operation. Furthermore, if conditions exist such that the increase in K_{Ia} exceeds K_{IT}, the calculated allowable pressure during cooldown will be greater than the steady-state value.

The above procedures are needed because there is **NO** direct control on temperature at the 1/4T location; therefore, allowable pressures may unknowingly be violated if the rate of cooling is decreased at various intervals along a cooldown ramp. The use of the composite curve eliminates this problem and assures conservative operation of the system for the entire cooldown period.

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Heatup

Three separate calculations are required to determine the limit curves for finite heatup rates. As is done in the cooldown analysis, allowable pressure-temperature relationships are developed for steady-state conditions as well as finite heatup rate conditions assuming the presence of a 1/4T defect at the inside of the vessel wall. The thermal gradients during heatup produce compressive stresses at the inside of the wall that alleviate the tensile stresses produced by internal pressure. The metal temperature at the crack tip lags the coolant temperature; therefore, the K_{Ia} for the 1/4T crack during heatup is lower than the K_{Ia} for the 1/4T crack during steady-state conditions at the same coolant temperature. During heatup, especially at the end of the transient, conditions may exist such that the effects of compressive thermal stresses and different K_{Ia} for steady-state and finite heatup rates do **NOT** offset each other and the pressure-temperature curve based on steady state conditions **NO** longer represents a lower bound of all similar curves for finite heatup rates when the 1/4T flaw is considered. Therefore, both cases have to be analyzed in order to assure that at any coolant temperature the lower value of the allowable pressure calculated for steady-state and finite heatup rates is obtained.

The second portion of the heatup analysis concerns the calculation of pressure-temperature limitations for the case in which a 1/4T deep outside surface flaw is assumed. Unlike the situation at the vessel inside surface, the thermal gradients established at the outside surface during heatup produce stresses which are tensile in nature and thus tend to reinforce any pressure stresses present. These thermal stresses, of course, are dependent on both the rate of heatup and the time (or coolant temperature) along the heatup ramp. Furthermore, since the thermal stresses at the outside are tensile and increase with increasing heatup rates, a lower bound curve cannot be defined. Rather, each heatup rate of interest must be analyzed on an individual basis.

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Following the generation of pressure-temperature curves for both the steady-state and finite heatup rate situations, the final limit curves are produced as follows. A composite curve is constructed based on a point-by-point comparison of the steady-state and finite heatup rate data. At any given temperature, the allowable pressure is taken to be the lesser of the three values taken from the curves under consideration.

The use of the composite curve is necessary to set conservative heatup limitations because it is possible for conditions to exist such that over the course of the heatup ramp the controlling condition switches from the inside to the outside and the pressure limit must at all times be based on analysis of the most critical situation.

Finally, the 10 CFR 50 Appendix G rule which addresses the metal temperature of the closure head flange and vessel flange regions is considered. The rule states that the minimum metal temperature for the flange regions should be at least 120°F higher than the limiting RT_{NDT} for these regions when the pressure exceeds 20 percent of the pre-service hydrostatic test pressure (621 psig). Since the limiting RT_{NDT} for the flange regions for Turkey Point Units 3 and 4 is -1°F, the minimum temperature required for pressure of 621 psig and greater based on the Appendix G rule is 119°F. The heatup and cooldown curves as shown in Figures 3.4-2 and 3.4-3 in the Technical specifications clearly satisfy the above requirement by ample margins.

Finally, the composite curves for the heatup rate data and the cooldown rate data are adjusted for possible errors in the pressure and temperature sensing instruments by the values indicated on the respective curves.

The limitations imposed on the Pressurizer heatup and cooldown rates and spray water temperature differential are provided to assure that the Pressurizer is operated within the design criteria assumed for the fatigue analysis performed in accordance with the ASME Code requirements.

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Overpressure Mitigating System

The Technical Specifications provide requirements to isolate High Pressure Safety Injection from the RCS and to prevent the start of an idle RCP if secondary temperature is more than 50°F above the RCS cold leg temperatures. These requirements are designed to ensure that mass and heat input transients more severe than those assumed in the low temperature overpressurization protection analysis cannot occur.

The OPERABILITY of two PORVs or an RCS vent opening of at least 2.20 square inches ensures that the RCS will be protected from pressure transients which could exceed the limits of Appendix G to 10 CFR Part 50 when one or more of the RCS cold legs are less than or equal to 275°F. Either PORV has adequate relieving capability to protect the RCS from overpressurization when the transient is limited to either: (1) The start of an idle RCP with the secondary water temperature of the steam generator less than or equal to 50°F above the RCS cold leg temperatures including margin for instrument error, or (2) The start of a HPSI pump and its injection into a water-solid RCS. When the PORVs or 2.2 square inch area vent is used to mitigate a plant transient, a Special Report is submitted. However, minor increases in pressure resulting from planned plant actions, which are relieved by designated openings in the system, need **NOT** be reported.

Associated requirements for accomplishing specific tests and verifications in SR 4.4.9.3.1.a and 4.4.9.3.1.d allow a 12 hour delay after decreasing RCS cold leg temperature to ≤ 275°F. The bases for the 12 hour relief in completing the ANALOG CHANNEL OPERATION TEST (ACOT) and verifying the OPERABILITY of the backup Nitrogen supply are provided in the proposed license amendment correspondence L-2000-146 and in the NRC Safety Evaluation Report provided in the associated Technical Specification Amendments 208/202 effective October 30, 2000.

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Based on the justifications provided therein and the discussion provided in NUREG-1431, Volume 1, Rev.2 (Westinghouse Standard Technical Specifications. Section B3.4.12), the 12 hour delay allowed for completing SR 4.4.9.3.1.a and 4.4.9.3.1.d is considered to start coincident with the enabling of OMS, regardless of RCS cold leg temperature. For example, if OMS is enabled at RCS cold leg temperature of 298°F, the ACOT must be completed within 12 hours of placing OMS in service (**NOT** 12 hours after decreasing RCS cold leg temperature to ≤ 275°F). (Reference: PTN-ENG-SENS-03-0046 approved 9/12/03.)

Reactor Material Surveillance Program

Each Type I capsule contains 28 V-notch specimens: ten Charpy specimens each, machined from the intermediate and lower shell forgings and eight Charpy specimens machined from correlated monitor material. In addition, each Type I capsule contains four tensile specimens (two specimens from each of the two shell forgings) and six Wedge Opening Loading (WOL) specimens (three specimens from each of the two shell forgings). Dosimeters of copper, nickel, aluminum-cobalt and cadmium-shielded aluminum-cobalt wire are secured in holes drilled in spacers at the top, middle, and bottom of each Type I capsule.

Each Type II capsule contains 32 Charpy V-notch specimens: eight specimens machined from the lower shell forgings, eight specimens of weld metal (Heat 71249), eight specimens of HAZ metal, and eight specimens of correlation monitor material. In addition, each Type II capsule contains four tensile specimens and four WOL specimens: two tensile specimens and two WOL specimens each from one of the shell forgings and the weld metal. Each Type II capsule contains a dosimeter block at the center of the capsule. Two cadmium-oxide-shielded capsules, containing the two isotopes uranium-238 and neptunium-237, are contained in the dosimeter block. The double containment afforded by the dosimeter assembly prevents loss and contamination by the neptunium-237 and uranium-238 and their activation products.

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Each dosimeter block contains approximately 20 milligrams of neptunium-237 and 13 milligrams of uranium-238 contained in a 3/8-inch OD sealed brass tube. Each tube is placed in a 1/2-inch diameter hole in the dosimeter block (one neptunium-237 and one uranium-238 tube per block), and the space around the tube is filled with cadmium oxide. After placement of this material, each hole is blocked with two 1/16-inch aluminum spacer discs and an outer 1/8-inch steel cover disc, which is welded in place. Dosimeters of copper, nickel, aluminum-cobalt and cadmium-shielded aluminum-cobalt are also secured in holes drilled in spacers located at the top, middle, and bottom of each Type II capsule.

Capsule Type	Capsule Identification
I	S, U, W, Y, and Z
II	T, V and X

This program combines the Reactor Surveillance Program into a single integrated program which conforms to the requirements of 10 CFR 50 Appendices G and H. The integrated program was approved by the NRC in a letter dated April 22, 1985, “Safety Evaluation by NRR Related to Amendment No. 112 to Facility Operating License No. DPR-31 and Amendment No. 106 to Facility Operating License No. DPR-41”, D.G. MacDonald to J.W. Williams.

3/4.4.10 Deleted

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3/4.4.11 Reactor Coolant System Vents

Reactor Coolant System vents are provided to exhaust noncondensible gases and/or steam from the Reactor Coolant System that could inhibit natural circulation core cooling. The OPERABILITY of at least one Reactor Coolant System vent path from the reactor vessel head and the pressurizer steam space ensures that the capability exists to perform this function.

The valve redundancy of the Reactor Coolant System vent paths serves to minimize the probability of inadvertent or irreversible actuation while ensuring that a single failure of a vent valve, power supply, or control system does **NOT** prevent isolation of the vent path.

Due to Appendix R considerations, the fuses for the Reactor Vessel Head Vent System solenoid valves are removed to prevent inadvertent opening of a leak path from the primary system during a fire (Ref: JPN-PTN-SEEJ-89-0076, Rev 1). The Reactor Vessel Head Vent System solenoid valves are considered operable with the fuses pulled since the removal and the administrative control of these fuses is controlled by plant procedures. The performances of the specified surveillances will verify the operability of the system.

The function, capabilities, and testing requirements of the Reactor Coolant System vents are consistent with the requirements of Item II.B.1 of NUREG-0737, Clarification of TMI Action Plan.

3/4.5 Emergency Core Cooling Systems

3/4.5.1 Accumulators

The OPERABILITY of each Reactor Coolant System (RCS) Accumulator ensures that a sufficient volume of borated water will be immediately forced into the reactor core through each of the cold legs in the event the RCS pressure falls below the pressure of the accumulators. This initial surge of water into the core provides the initial cooling mechanism during large RCS pipe ruptures.

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3/4.5.1 (Continued)

For an Accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above 1000 psig, and the limits established in the surveillance requirements for contained volume, boron concentration, and nitrogen cover pressure must be met. Operability of the accumulators does **NOT** depend on the Operability of the water level and pressure channel instruments, therefore, Accumulator volume and nitrogen cover pressure surveillance may be verified by any valid means, **NOT** just by instrumentation.

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, 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 Loss of Coolant Accident (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. In addition, current Turkey Point analysis demonstrates that the Accumulators discharge only a small amount following a large main steam line break. Their impact is minor since the use of the Accumulator volume compensates for Reactor Coolant System shrinkage and the change in boron concentration is insignificant. Thus, 72 hours is allowed to return the boron concentration to within limits.

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 three Accumulators 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.

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3/4.5.2
&
3/4.5.3 ECCS Subsystems

The OPERABILITY of ECCS components and flowpaths required in MODES 1, 2, and 3 ensures that sufficient emergency core cooling capability will be available in the event of a LOCA assuming any single active failure consideration. Two SI pumps and one RHR pump operating in conjunction with two accumulators are capable of supplying sufficient core cooling to limit the peak cladding temperatures within acceptable limits for all pipe break sizes up to and including the maximum hypothetical accident of a circumferential rupture of a reactor coolant loop. The integrity of the cold leg injection flowpath can be impacted by the opposite unit if a discharge path is opened in a low pressure condition. This is **NOT** normally a concern based on the opposite unit operating at 2235 psig maintaining cold leg injection check valves closed. In addition, the RHR subsystem provides long-term core cooling capability in the RECIRCULATION mode during the accident recovery period. Management of gas voids is important to ECCS OPERABILITY.

Motor Operated Valves (MOVs) 862A, 862B, 863A, 863B are required to take suction from the containment sump via the RHR System.
PC-600 supplies controlling signals to valves MOVs 862B and 863B, to prevent opening these valves if RHR Pump B discharge pressure is above 210 psig. PC-601 provides similar functions to valves MOVs 862A and 863A. Although all four valves are normally locked in position, with power removed, the capability to power up and stroke the valves must be maintained in order to satisfy the requirements for OPERABLE flow paths (capable of taking suction from the containment sump).

When PC-600/-601 are calibrated, a test signal is supplied to each circuit to check operation of the relays and annunciators operated by subject controllers. This test signal will prevent MOVs 862A, 862B, 863A, 863B from opening. Therefore, it is appropriate to tag out the MOV breakers, and enter Technical Specification Action Statement 3.5.2.a. and 3.6.2.1 when calibrating PC-600/-601.

With the RCS temperature below 350°F, operation with less than full redundant equipment is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the limited core cooling requirements.

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3/4.5.2 & 3/4.5.3 (Continued)

TS 3.5.2, Action g. provides an allowed outage/action completion time (AOT) of up to 7 days to restore an inoperable RHR Pump to OPERABLE status, provided the affected ECCS Subsystem is inoperable only because its associated RHR pump is inoperable. This 7 day AOT is based on the results of a deterministic and probabilistic safety assessment, and is referred to as a Risk-Informed AOT Extension. Planned entry into this AOT requires that a Risk Assessment be performed in accordance with the Configuration Risk Management Program (CRMP), which is described in the administrative procedure that implements the Maintenance Rule pursuant to 10 CFR 50.65. If an RHR pump suction isolation valve (3/4-752A or B) is CLOSED, then one of the two required flow paths from the containment sump becomes INOPERABLE and TS LCO 3.5.2.e is **NOT** met. In this case, TS 3.5.2, Action a, is entered and the AOT for the inoperable flow path is 72 hours.

TS 3.5.2, Action h. limits the allowed outage time for an inoperable RWST flow path from the RWST(s) required by TS 3.5.4 to 1 hour consistent with the allowed outage time for a required RWST.

NOTE

License Amendments 267 and 262 corrected two non-conservative Technical Specifications (TS) but resulted in the unintended consequence of having no ACTION specifically applicable to one of two safety injection (MOV-*-843) or residual heat removal (MOV-*-744) parallel injection valves inoperable. Previously, TS 3.5.2, Action 'a' was applied allowing a 72 hour allowed outage time (AOT). For the times when one of the 843s or 744s is inoperable, a 72 hour AOT should continue to be applied in accordance with Special Instruction 16-002 until License Amendment Request 249 is submitted, approved by the NRC, and implemented.

TS Surveillance Requirement 4.5.2.a requires that each ECCS component and flow path be demonstrated operable by verifying by Control Room indication that the valves listed in TS SR 4.5.2.a are in the indicated positions with power to the valve operators removed. Verifying Control Room indication applies to the valve position and **NOT** to the valve operator power removal.

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The breaker position may be verified by either the off condition of the breaker position indication light in the Control Room, or the verification of the locked open breaker position in the field. Verifying that power is removed to the applicable valve operators can be accomplished by direct field indication of the breaker (locked in the open position), or by observation of the breaker position status lamp in the Control Room (lamp is off when breaker is open). Power may be restored to a valve for up to 1 hour for surveillance or maintenance purposes.

TS Surveillance Requirement 4.5.2.g for throttle valve position stops prevent total pump flow from exceeding runout conditions when the system is in its minimum resistance configuration. Surveillance frequencies **NOT** included in the Technical Specifications are controlled under the Surveillance Frequency Control Program.

ECCS piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS and may also prevent a water hammer, pump cavitation, and pumping of non-condensable gas into the reactor vessel.

Selection of ECCS locations susceptible to gas accumulation is based on a review of system design information, including piping and instrument drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

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3/4.5.2 & 3/4.5.3 (Continued)

The ECCS is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the ECCS is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

ECCS locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The 31 day frequency for SR 4.5.2.b.1) takes into consideration the gradual nature of gas accumulation in the ECCS piping and the procedural controls governing system operation.

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Surveillance 4.5.2.b.2) is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the Control Room. This individual will have a method to rapidly close the system vent path if directed.

In the RHR test, differential head is specified in feet. This criteria will allow for compensation of test data with water density due to varying temperature.

ECCS pump testing for the SI and RHR pumps accounts for possible underfrequency conditions, i.e., the results of pump testing performed at 60 Hz is then adjusted to reflect possible degraded grid conditions (60±0.6) to the lower limit (59.4 Hz).

Technical Specifications Surveillance Requirement 4.5.2.e.3 requires that each ECCS component and flow path be demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program by visual inspection which verifies sump components (trash racks, screens, etc.) show **NO** evidence of structural distress or abnormal corrosion. The strainer modules are rigid enough to provide both functions as trash racks and screens without losing their structural integrity and particle efficiency. Therefore, strainer modules are functionally equivalent to trash racks and screens. Accordingly, the categorical description, sump components, is broad enough to require inspection of the strainer modules.

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3/4.5.4 Refueling Water Storage Tank

Pump performance requirements are obtained from accident analysis assumptions. Varying flowrates are provided to accommodate testing during modes and alignments.

The OPERABILITY of the Refueling Water Storage Tank (RWST) as part of the ECCS ensures that a sufficient supply of borated water is available for injection by the ECCS in the event of a LOCA. The limits on RWST minimum volume and boron concentration ensure that: (1) Sufficient water is available within containment to permit recirculation cooling flow to the core, and (2) The reactor will remain subcritical in the cold condition following mixing of the RWST and the RCS water volumes with all control rods assumed out of the core to maximize boron requirements.

The assumptions made in the LOCA analyses credit control rods for the SBLOCA and cold leg large break LOCA and do **NOT** credit control rods for the hot leg large break LOCA. For the Cold Leg Large Break LOCA, control rods are assumed inserted only at the time of hot leg switchover to provide the additional negative reactivity required to address concerns of potential core recriticality at the time. (Reference: PTN-ENG-SEFJ-02-016 approved 11/14/03, PNSC #03-167.)

The indicated water volume limit includes an allowance for water **NOT** usable because of tank discharge line location or other physical characteristics.

The temperature limits on the RWST solution ensure that:
1) The solubility of the borated water will be maintained, and
2) The temperature of the RWST solution is consistent with the LOCA analysis. Portable instrumentation may be used to monitor the RWST temperature.

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3/4.6 Containment Systems

3/4.6.1 Primary Containment

3/4.6.1.1 Containment Integrity

Primary CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the dose guideline values of 10 CFR 50.67 during accident conditions.

Note that some penetrations do **NOT** fall under Technical Specification 3.6.1.1. For example Penetration 38 is an electrical penetration only, closed by virtue of its seals, and therefore, nothing needs to happen to close the penetration during accident conditions; it is considered already closed. A passive failure would be required in order to get communication between the containment atmosphere and the outside atmosphere through this penetration (Turkey Point's license does **NOT** require consideration of passive failures). Similarly, closed systems inside Containment already satisfy the requirement for CONTAINMENT INTEGRITY, so Tech Spec 3.6.1.1 does **NOT** apply to them at all (unless the piping itself is breached, which would be a passive failure).

The primary CONTAINMENT INTEGRITY requirement of Technical Specification 3.6.1.1 is modified by a Note allowing containment penetrations to be unisolated by opening the associated valves and airlocks under Administrative Controls when necessary to perform surveillance, testing requirements, and/or corrective maintenance. The Note also enforces compliance with Specification 3.6.4, in conjunction with Specification 3.6.1.1. The Administrative Controls shall consist of a dedicated person that is assigned the responsibility to close the valve(s) in the event of an emergency or when operation is complete.

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3/4.6.1.1 (Continued)

The activity which places the Pressurizer steam space vent in service to remove noncondensible gases from the Reactor Coolant System (RCS) is considered a corrective maintenance activity for the purposes of Technical Specification 3.6.1.1 compliance. Nitrogen, the primary noncondensible gas contributor, enters the RCS during refueling outages when it is used as a cover gas in the Volume Control Tank and from exposure of the reactor coolant to atmospheric conditions during the refueling sequence. The Pressurizer heaters drive these gases out of solution during RCS heatup and they collect in the Pressurizer steam space. This causes two problems. First, the Pressurizer does **NOT** respond to spray actuation, creating a “hard bubble.” Second, the noncondensible gases migrate to the reference leg condensing pots of the Pressurizer level instruments, preventing reference leg makeup and proper indication of Pressurizer liquid level. The Pressurizer steam space venting activity is necessary to correct these problems and achieve and maintain acceptable nitrogen levels in the RCS. Accordingly, opening the containment penetration isolation valves needed to conduct the Pressurizer steam space venting maintenance activity is typically performed under Administrative Controls in accordance with the provisions of the noted exception to the CONTAINMENT INTEGRITY requirement of Technical Specification 3.6.1.1.

With these distinctions, Surveillance Requirement 4.6.1.1 is explained as follows: (1) As long as a penetration is capable of being closed by an OPERABLE containment automatic isolation valve system and Technical Specification 3.6.4 is met, then 4.6.1.1 is met, and (2) If the penetration is **NOT** required to be closed during accident conditions, 4.6.1.1 is met. For example, penetrations 58 and 59 are for High Head Safety Injection, and therefore, required to be open during accident conditions. Penetrations which do **NOT** meet one of the two criteria listed above (automatic valve, or **NOT** requiring closure), require verification that they are already closed by some other means (valve, blind flange, or deactivated automatic valve). Note that a deactivated automatic valve must be administratively controlled (tagged) in the closed position to take credit for it as a deactivated valve.

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3/4.6.1.2 Containment Leakage

The limitations on containment leakage rates ensure that the total containment leakage volume will **NOT** exceed the value assumed in the safety analyses at the peak accident pressure, Pa. The measured As Found overall integrated leakage rate is limited to less than or equal to 1.0 La during the performance of the periodic test. As an added conservatism, the measured overall As Left integrated leakage rate is further limited to less than or equal to 0.75 La to account for possible degradation of the containment leakage barriers between leakage tests.

The surveillance testing for measuring leakage rates is in compliance with the requirements of Appendix J of 10 CFR Part 50, Option B [as modified by approved exemptions], and consistent with the guidance of Regulatory Guide 1.163, dated September 1995.

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3/4.6.1.3 Containment Air Locks

The limitations on closure and leak rate for the Containment Air Locks are required to meet the restrictions on CONTAINMENT INTEGRITY and Containment Leak Rate. An interlock is provided on the Airlock to assure that both doors cannot be opened simultaneously, with the consequent loss of Containment Integrity with the interlock inoperable, Action Statement (AS) (a.) applies. With an interlock inoperable such that the closure of only one door can be assured, Containment Integrity can be maintained by complying with AS (a.1) without reliance on the status of the second door. Surveillance testing of the air lock seals provides assurance that the overall air lock leakage will **NOT** become excessive due to seal damage during the intervals between air lock leakage tests. Surveillance 4.6.1.3 assures the operability of an air lock by verifying the operability of door seals in Surveillance Requirement (SR) (a.), other potential leak paths in SR (b.), and the interlock in SR (c.). If SR (a.) or (c.) are **NOT** met, then a door is to be considered inoperable. (If both doors are incapable of being closed, the air lock is inoperable). If SR (b.) is **NOT** met, and the source of the leak is **NOT** identified or is confirmed to **NOT** be through a door, then the air lock is to be considered inoperable. In order to meet the ACTION requirement to lock the OPERABLE air lock door closed, the air lock door interlock may provide the required locking. In addition, the outer air lock door is secured under administrative controls. As long as the interlock physically prevents the door from being opened, the interlock is OPERABLE, and therefore, the airlock is OPERABLE. However, should the air lock door begin to un-seal while performing the interlock test (such that the door leakage may be in question), the door would be considered inoperable (and the associated actions for one inoperable door taken). A containment air lock door would be considered open whenever the latch handle is out of the Latched position such that the door is free to open with a slight force, i.e., the door is closed but unlatched. The door should be considered closed whenever the latch mechanism physically prevents the door from being opened. With a containment air lock interlock mechanism inoperable, consider one containment airlock door out of service and maintain the other door closed and locked. During the air lock interlock test (SR (c.)), when an attempt is made to move the door handle in the unlatched direction, some movement in the handle may occur until the mechanical interlock makes hard contact.

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At this point the door is still physically restrained from opening, but the seating pressure against the o-ring seal may have been reduced such that the door seal is in an untested configuration, potentially creating a leakage path. In this configuration, the door is considered closed per the Technical Specifications and would satisfy the interlock test requirements, but the overall air lock leakage requirement may have been invalidated. This configuration would result in an inoperable airlock door since the O-ring seal was **NOT** properly compressed. As there is **NO** functional difference between an unsecured door and a leaking door (as far as maintenance of containment integrity is concerned), the unsecured door must be considered inoperable.

3/4.6.1.4 Internal Pressure

The limitations on Containment Internal Pressure ensure that: (1) The containment structure is prevented from exceeding its design negative pressure differential of 2.5 psig with respect to the outside atmosphere, and (2) The containment peak pressure does **NOT** exceed the design pressure of 55 psig during LOCA conditions.

3/4.6.1.5 Air Temperature

The limitations on containment average air temperature ensure that the design limits for a LOCA are **NOT** exceeded, and that the environmental qualification of equipment is **NOT** impacted. If temperatures exceed 120°F, but remain below 125°F for up to 336 hours during a calendar year, **NO** action is required. If the 336-hour limit is approached, an evaluation may be performed to extend the limit if some of the hours have been spent at less than 125°F. Measurements shall be made at all listed locations, whether by fixed or portable instruments, prior to determining the average air temperature.

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3/4.6.1.6 Containment Structural Integrity

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the facility. Structural integrity will be required to ensure that the containment will withstand the design pressure of 55 psig in the event of a LOCA. The measurement of containment tendon lift-off force, the tensile tests of the tendon wires or strands, the visual examination of tendons, anchorages and exposed interior and exterior surfaces of the containment, and the Type A leakage test are sufficient to demonstrate this capability.

Some containment tendons are inaccessible at one end due to personnel safety considerations at potential steam exhaust locations. These tendons, if selected for examination, will be exempted from the full examination requirements, and the following alternative examinations shall be performed:

1. The accessible end of each exempt tendon shall be examined in accordance with IWL 2524 and IWL-2525.

2. For each exempt tendon, a substitute tendon shall be selected and examined in accordance with IWL requirements.

3. In addition, an accessible tendon located as close as possible to each exempt tendon shall be examined at both ends in accordance with IWL-2524 and IWL 2525.

The required Special Reports from any engineering evaluation of containment abnormalities shall include a description of the tendon condition, the condition of the concrete (specially at tendon anchorages), the inspection procedures, the tolerances on cracking, the results of the engineering evaluation, and the corrective actions taken.

The submittal of a Special Report for a failed tendon surveillance is considered an administrative requirement and it does **NOT** impact the plant operability. The administrative requirements for Special Reports are defined in Technical Specifications Section 6.9.2.

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3/4.6.1.7 Containment Ventilation System

The Containment Purge supply and exhaust isolation valves are required to be closed during a LOCA. When **NOT** purging, power to the purge valve actuators will be removed (sealed closed) to prevent inadvertent opening of these values. Maintaining these valves sealed closed during plant operation ensures that excessive quantities of radioactive materials will **NOT** be released via the Containment Purge System.

Leakage integrity tests with a maximum allowable leakage rate for Containment Purge supply and exhaust supply valves will provide early indication of resilient material seal degradation and will allow opportunity for repair before gross leakage failures could develop. The 0.60 La leakage limit shall **NOT** be exceeded when the leakage rates determined by the leakage integrity tests of these valves are added to the previously determined total for all valves and penetrations subject to Type B and C tests.

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3/4.6.2 Depressurization and Cooling Systems

3/4.6.2.1 Containment Spray System

The OPERABILITY of the Containment Spray System ensures that containment depressurization capability will be available in the event of a LOCA. The pressure reduction and resultant lower containment leakage rate are consistent with the assumptions used in the safety analyses. Management of gas voids is important to Containment Spray System OPERABILITY.

The allowable out-of-service time requirements for the Containment Spray System have been maintained consistent with that assigned other inoperable ESF equipment and do **NOT** reflect the additional redundancy in cooling capability provided by the Emergency Containment Cooling System. Pump performance requirements are obtained from the accidents analysis assumptions.

Motor Operated Valves (MOVs) 862A, 862B, 863A, 863B are required to take suction from the Containment Sump via the RHR system. PC-600 supplies controlling signals to valves MOVs 862B and 863B, to prevent opening these valves if RHR pump B discharge pressure is above 210 psig. PC-601 provides similar functions to valves MOVs 862A and 863A. Although all four valves are normally locked in position, with power removed, the capability to power up and stroke the valves must be maintained in order to satisfy the requirements for OPERABLE flow paths (capable of taking suction from the containment sump).

When PC-600/-601 are calibrated, a test signal is supplied to each circuit to check operation of the relays and annunciators operated by subject controllers. This test signal will prevent MOVs 862A, 862B, 863A, 863B from opening. Therefore, it is appropriate to tag out the MOV breakers, and enter Technical Specification Action Statement 3.5.2.a. and 3.6.2.1 when calibrating PC-600/-601.

Containment Spray System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the containment spray trains and may also prevent a water hammer and pump cavitation.

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Selection of Containment Spray System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrument drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The Containment Spray System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the Containment Spray System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

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3/4.6.2.1 (Continued)

Containment Spray System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The 31 day frequency for SR 4.6.2.1.c takes into consideration the gradual nature of gas accumulation in the Containment Spray System piping and the procedural controls governing system operation.

SR 4.6.2.1.a is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent path if directed.

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3/4.6.2.2 Emergency Containment Cooling System

The OPERABILITY of the Emergency Containment Cooling (ECC) System ensures that the heat removal capacity is maintained within acceptable ranges following postulated design basis accidents. To support both containment integrity safety analyses and component cooling water thermal analysis, two ECCs must start and run within 60 seconds of receipt of a safety injection (SI) signal (one ECC receives an A train SI signal and another ECC receives a B train SI signal). The third (swing) ECC is required to automatically start upon failure of either of the other two ECCs to start.

The allowable out-of-service time requirements for the Containment Cooling System have been maintained consistent with that assigned other inoperable ESF equipment and do **NOT** reflect the additional redundancy in cooling capability provided by the Containment Spray System.

The surveillance requirement for ECC flow is verified by correlating the test configuration value with the design basis assumptions for system configuration and flow. The surveillance interval is based on the use of water from the CCW system, which results in a low risk of heat exchanger tube fouling. The surveillance frequency is controlled under the Surveillance Frequency Control Program.

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3/4.6.2.3 Recirculation pH Control System

The Recirculation pH Control System is a passive safeguard consisting of 10 stainless steel wire mesh baskets (2 large and 8 small) containing sodium tetra borate decahydrate (NaTB) located in the containment basement (14' elevation). The initial containment spray will be boric acid solution from the Refueling Water Storage Tank. The recirculation pH control system adds NaTB to the Containment Sump when the level of boric acid solution from the Containment Spray and the coolant lost from the Reactor Coolant System rises above the bottom of the buffering agent baskets. As the sump level rises, the NaTB will begin to dissolve. The addition of NaTB from the buffering agent baskets ensures the containment sump pH will be greater than 7.0. The resultant alkaline pH of the spray enhances the ability of the recirculated spray to scavenge fission products from the containment atmosphere. The alkaline pH in the recirculation sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on stainless steel piping systems exposed to the solution.

The OPERABILITY of the recirculation pH control system ensures that there is sufficient NaTB available in the containment to ensure a sump pH greater than 7.0 during the recirculation phase of a postulated LOCA. The baskets will **NOT** interact with surrounding equipment during a seismic event.

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To achieve this, the analysis considered the minimum and maximum quantities of boron and borated water, the time-dependent post-LOCA sump temperatures, and the minimum time to reach switchover conditions. In addition, the formation of acid from radiolysis of air and water, radiolysis of chloride bearing electrical cable insulation and jacketing, and spilled reactor coolant were considered. Since, **NOT** all of the NaTB will be dissolved at the onset of containment spray recirculation, the final long-term pH was also calculated. The table below provides a summary of the quantities of NaTB and resulting pH values at the onset of recirculation and long-term.

Case No.	Purpose Min/Max pH	Small Basket Fill Height (ft)	Large Basket Fill Height (ft)	Initial NaTB Mass (lbm)	Dissolved Mass prior to Recirc (lbm)	pH at Recirc	Long-Term pH
1	Min	1.31	1.464	7500	4097	7.045	7.111 (min)
2	Min	1.9167	2.1867	11061	4637	7.103	7.366 (min)
3	Max	2.5	2.77	15816	15816	8.048	8.048 (max)

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To satisfy the surveillance requirement, the two large baskets and eight small baskets must contain a combined mass greater than 7500 lbm of NaTB. As shown in the above table, this will ensure the sump pH exceeds 7.0 at the onset of spray recirculation and for the duration of the analyzed 30-day period. The large baskets have a length and width of 54 inches, and a height of 33.25 inches and are elevated 3.5 inches above the containment floor. The smaller baskets have a length and width of 36 inches and a height of 30 inches and are elevated 4.5 inches above the containment floor. Varying basket dimensions or elevation (e.g. basket leg height) impacts the surface to volume ratio and changes the time the NaTB is in contact with containment sump water. For instance, shorter legs would allow the NaTB to contact containment sump water sooner, therefore increasing the pH at the onset of recirculation. Longer legs, however, would reduce the pH at the onset of recirculation. The level of NaTB in the baskets required to provide an equilibrium sump solution pH greater than 7.0 is 14.75 inches from the top of the basket; 18.50 inches for the large baskets and 15.25 inches for the small baskets from the bottom of the basket. Surveillance Requirement 4.6.2.3 ensures that the stainless steel buffering agent baskets are intact and contain the required quantity of NaTB. The surveillance frequency is controlled under the Surveillance Frequency Control Program.

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3/4.6.3 Deleted

3/4.6.4 Containment Isolation Valves

The OPERABILITY of the Containment Isolation Valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment. Containment isolation within the time limits specified in the In-Service Testing Program is consistent with the assumed isolation times of those valves with specific isolation times in the LOCA analysis.

Note that Tech Spec 3.6.4 applies only to automatic Containment Isolation Valves. Automatic Containment Isolation Valves are valves, which close automatically on a Containment Isolation Phase A signal, Containment Phase B, or a Containment Ventilation Isolation signal, and check valves.

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3/4.6.4 (Cont'd)

The term "penetration" used in the Action statements is synonymous with the term "penetration flow path" which is intended to more accurately address containment penetrations that may have more than one flow path. For example, the CVCS letdown penetration has three parallel power operated automatic inside containment isolation valves and a single series power operated automatic outside containment isolation valve. This penetration has three normal flow paths associated with the three RCS loops. Each inside power operated automatic containment isolation valve is in series with the single outside containment isolation valve and constitutes a separate flow path. The Actions may be applied separately to each flow path in this penetration. In the example of the CVCS letdown penetration, if one of the three inside isolation valves is inoperable, it becomes the "affected" flow path and, in accordance with the Actions, must be isolated. Isolating the "affected" flow path in this example may be accomplished by closing the inoperable inside containment isolation valve. With the inside containment isolation valve closed in this case, the penetration is **NO** longer open. Because the inside and outside containment isolation valves in this case are associated with opposite trains, for both the electric power source and the isolation signal, and the outside valve does **NOT** require closure to isolate the flow path. Therefore, the other two CVCS flow paths associated with this penetration may remain in service since the capability to isolate these remaining flow paths, assuming a single active failure, is unaffected. However, if the single outside containment CVCS letdown isolation valve becomes inoperable, then the capability to isolate the individual flow paths associated with this penetration, assuming a single active failure, would **NO** longer exist. Therefore, all three flow paths associated with this penetration would be affected, and the Action to isolate the affected flow paths would be applicable to all flow paths associated with this penetration. (Reference: AR 547802)

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3/4.7 Plant Systems

3/4.7.1 Turbine Cycle

3/4.7.1.1 Safety Valves

The OPERABILITY of the main steam line Code Safety Valves ensures that the Secondary System pressure will be limited to within 110% (1193.5 psig) of its design pressure of 1085 psig during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a Turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., **NO** steam bypass to the condenser).

The primary purpose of the Main Steam Safety Valves (MSSVs) is to provide overpressure protection for the Secondary System. The MSSVs also provide protection against over pressurizing 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 heat sink, provided by the Condenser and Circulating Water System, is **NOT** available.

Four MSSVs are located on each Main Steam Header, outside Containment, upstream of the Main Steam Isolation Valves, as described in the UFSAR, Section 10.2. The MSSVs must have sufficient capacity to limit the secondary system pressure to less than or equal 110% of the steam generator design pressure in order to meet the requirements of ASME Code, Section III. The total relieving capacity for all valves on all of the steam lines is 9.936×10^6 lbs/hr which is 85.27% of the total secondary steam flow of 11.65×10^6 lbs/hr at 100% RATED THERMAL POWER. The MSSV design includes staggered setpoints, according to Table 3.7-2 in the accompanying limiting condition for operation (LCO), 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.

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STARTUP and/or POWER OPERATION is allowable with Safety Valves inoperable within the limitations of the ACTION requirements on the basis of the reduction in Secondary Coolant System steam flow and THERMAL POWER required by the reduced Reactor Trip settings of the Power Range Neutron Flux channels. The Reactor Trip Setpoint reductions are derived on the following bases:

$$Hi_{\Phi} = (100/Q) \frac{(w_s \; h_{fg} \; N)}{K}$$

Where:

Hi_{Φ} = Reduced THERMAL POWER for the most limiting Steam Generator expressed as a percent of RTP

Q = Nominal Nuclear Steam Supply System (NSSS) power rating of the plant (including reactor coolant pump heat), Mwt

K = Conversion factor; 947.82 (Btu/sec)/Mwt

ws = Minimum total steam flow rate capability of the operable MSSVs on any one Steam Generator at the highest MSSV opening pressure (including tolerance and accumulation) (Lbm/sec). For example, if the maximum number of inoperable MSSVs on any one Steam Generator is one, then ws should be a summation of the capacity of the operable MSSVs at the highest operable MSSV operating pressure, excluding the highest capacity MSSV. If the maximum number of inoperable MSSVs per Steam Generator is three, then ws should be a summation of the capacity of the operable MSSV at the highest operable MSSV operating pressure, excluding the three highest capacity MSSVs.

hfg = Heat of Vaporization for steam at the highest MSSV opening pressure (including tolerance and accumulation) - (Btu/lbm)

N = Number of loops in plant

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The values calculated from this algorithm must then be adjusted lower for use in TS 3.7.1.1 to account for instrument and channel uncertainties.

Operation with less than all four MSSVs OPERABLE for each Steam Generator is permissible, if THERMAL POWER is proportionally limited to the relief capacity of the remaining MSSVs. This is accomplished by restricting THERMAL POWER so that the energy transfer to the most limiting Steam Generator is **NOT** greater than the available relief capacity in that Steam Generator. Table 3.7-2 allows a ± 3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the surveillance to allow for drift.

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3/4.7.1.2 Auxiliary Feedwater System

The OPERABILITY of the Auxiliary Feedwater System ensures that the Reactor Coolant System can be cooled down to less than 350°F from normal operating conditions in the event of a total Loss-Of-Offsite Power. Two independent AFW trains, including three redundant steam supply flowpaths, three pumps (and associated steam turbines, trip and throttle (T&T) valves and governor valves) and their associated discharge water flowpaths, are required to be OPERABLE. Steam can be supplied to the pump turbines from either or both units through redundant steam headers. Two D.C. motor operated valves and one A.C. motor operated valve on each unit isolate the three main steam lines from these headers. Both the D.C. and A.C. motor operated valves are powered from safety-related sources. Auxiliary feedwater can be supplied through redundant lines to the safety-related portions of the main feedwater lines to each of the steam generators. Air operated fail closed flow control valves are provided to modulate the flow to each steam generator. Each Steam Driven Auxiliary Feedwater Pump has sufficient capacity for single and two unit operation to ensure that adequate feedwater flow is available to remove decay heat and reduce the Reactor Coolant System temperature to less than 350°F when the Residual Heat Removal System may be placed into operation.

Note 1 describes the AFW system alignment(s) which ensure that three AFW steam supply flowpaths are OPERABLE. This is typically accomplished by aligning the SG/C steam supply flowpath (via MOV-3/4-1405) to train #1, the SG/A steam supply flowpath (via MOV-3/4-1403) to train #2, and the SG/B steam supply flowpath (via MOV-3/4-1404) to either train 1 or 2, but not both simultaneously.

Note 2 describes the AFW system alignment(s) which ensure that three AFW pumps are OPERABLE. This is typically accomplished by aligning the ‘A’ AFW pump to train 1, the ‘B’ AFW pump to train 2, and the ‘C’ AFW pump aligned to either train 1 or 2. The alignment applies during both single and dual Unit operation. The steam turbine, trip and throttle valve, and governor valve are support components for each AFW pump.

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3/4.7.1.2 (Continued)

ACTION statement 1 describes the actions to be taken when one of the two required independent AFW trains is inoperable. Two redundant AFW trains must be OPERABLE in order to satisfy the design basis requirement that the AFW System meet the single failure criterion in response to a MSLB. The 72-hour ACTION statement for an inoperable AFW train is reasonable based on the redundant capabilities afforded by the AFW system, the time needed for repairs, and the low probability of a DBA occurring during this time period. Additionally, the 72-hour ACTION statement is consistent with the 72-hour completion time specified in TS 3.7.5 of NUREG-1431, Revision 4, for one inoperable AFW train.

ACTION statement 2 describes the actions to be taken when both Auxiliary Feedwater Trains are inoperable. The requirement to verify the availability of both Standby Feedwater Pumps is to be accomplished by verifying that both pumps have successfully passed their surveillance tests within the last surveillance interval. The requirement to complete this action before beginning a unit shutdown is to ensure that an alternate feedwater train is available before putting the affected unit through a transient. If **NO** alternate feedwater trains are available, the affected unit is to stay at the same condition until an auxiliary feedwater train is returned to service, and then invoke ACTION statement 1 for the other train. If both Standby Feedwater Pumps are made available before one Auxiliary Feedwater Train is returned to an OPERABLE status, then the affected units shall be placed in at least HOT STANDBY within 6 hours and HOT SHUTDOWN within the following 6 hours.

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ACTION statement 3 describes the actions to be taken when a single Auxiliary Feedwater Pump is inoperable. The requirement to verify that two independent Auxiliary Feedwater Trains are OPERABLE is to be accomplished by verifying that one OPERABLE AFW pump is aligned to each AFW train and that all three steam supply flowpaths are OPERABLE. The provisions of Specification 3.0.4 are **NOT** applicable to the third auxiliary feedwater pump provided it has **NOT** been inoperable for longer than 30 days. This means that a units can change OPERATIONAL MODES during a unit's heatup with a single Auxiliary Feedwater Pump inoperable as long as the requirements of ACTION Statement 3 are satisfied.

ACTION statement 4 describes the actions to be taken when a single steam supply flowpath is inoperable. Three AFW steam supply flowpaths must be OPERABLE in order to satisfy the design basis requirement that the AFW System meet the single failure criterion in response to a MSLB. Consistent with ACTION statement 3, four hours are available to verify the OPERABILITY of two independent steam supply flowpaths or otherwise ACTION statements 1 or 2 apply. Upon verification of the OPERABILITY of two steam supply flowpaths, seven days is allotted to restore the inoperable steam supply flowpath to OPERABLE status from the time of discovery. The seven day ACTION statement is less restrictive than the 72-hour ACTION statement for an inoperable AFW train but more restrictive than the 30-days allotted for an inoperable AFW pump. The consequences of an inoperable steam supply flowpath are more severe than for an inoperable AFW pump. With a MSLB with one AFW steam supply flowpath out of service not associated with the faulted loop, failure of the remaining OPERABLE steam supply flowpath would cause a loss of AFW System function. Additionally, the seven day ACTION statement is consistent with the 7-day completion time specified in TS 3.7.5 of NUREG-1431, Revision 4, for one inoperable turbine driven AFW pump steam supply flowpath.

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The specified flow rate acceptance criteria conservatively bounds the limiting AFW flow rate modeled in the single unit Loss of Normal Feedwater analysis. Dual unit events such as a two unit Loss of Offsite Power require a higher pump flow rate, but it is **NOT** practical to test both units simultaneously. The flow surveillance test specified in 4.7.1.2.1a.1 is considered to be a general performance test for the AFW system and does **NOT** represent the limiting flow requirement for AFW. Check valves in the AFW system that require full stroke testing under limiting flow conditions are tested in accordance with the Inservice Testing Program.

The testing of the Auxiliary Feedwater Pumps will verify their OPERABILITY. Proper functioning of the turbine admission valve and the operation of the pumps will demonstrate the integrity of the system. Verification of correct operation will be made both from instrumentation within the Control Room and direct visual observation of the pumps.

The frequencies of surveillance requirements 4.7.1.2.1a and 4.7.1.2.1b are controlled under the Surveillance Frequency Control Program.

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3/4.7.1.3 Condensate Storage Tank

There are two seismically designed Condensate Storage Tanks each with a capacity of 250,000 gallons. A minimum indicated volume of 210,000 gallons is maintained for each unit in MODES 1, 2 or 3 which provides margin over the analysis minimum required volume of 207,637 gallons per PTN-BFJM-95-008. The OPERABILITY of the Condensate Storage Tank with the minimum indicated volume ensures that sufficient water is available to maintain the Reactor Coolant System at HOT STANDBY conditions for approximately 18 hours or maintain the Reactor Coolant System at HOT STANDBY conditions for 4 hours and 9 hours to cool down the Reactor Coolant System to below 350°F at which point the Residual Heat Removal System may be placed in operation.

The minimum indicated volume includes an allowance for instrument indication uncertainties and for water deemed unusable because of vortex formation and the configuration of the discharge line.

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3/4.7.1.4 Specific Activity

The limit on secondary coolant Specific Activity is based on a postulated release of secondary coolant equivalent to the contents of three Steam Generators to the atmosphere due to a net load rejection. The limiting dose for this case would result from radioactive iodine in the secondary coolant. One tenth of the iodine in the secondary coolant is assumed to reach the site boundary making allowance for plate-out and retention in water droplets. The inhalation thyroid dose at the site boundary is then;

Dose (Rem) = C * V * B * DCF * X/Q * 0.1

Where: C = secondary coolant dose equivalent I-131 specific activity

=0.2 curies/ m^3 (*μCi/cc) or 0.1 Ci/m^3 , each unit

V = equivalent secondary coolant volume released = 214m^3

B = breathing rate = 3.47 x 10^{-4} m^3/sec.

X/Q = atmospheric dispersion parameter = 1.54 x 10^{-4} sec/m^3

0.1 = equivalent fraction of activity released

DCF = dose conversion factor, Rem/Ci

The resultant thyroid dose is less than 1.5 Rem.

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3/4.7.1.5 Main Steam Line Isolation Valves

The OPERABILITY of the Main Steam Line Isolation Valves (MSIV) ensures that **NO** more than one Steam Generator will blow down in the event of a steam line rupture. This restriction is required to: (1) Minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and (2) Limit the pressure rise within Containment in the event a Main Steam Line or Feedwater Line rupture occurs within Containment. The OPERABILITY of the Main Steam Isolation Valves within the closure times of the Surveillance Requirements are consistent with the assumptions used in the Safety Analyses. The 24 hour ACTION time provides a reasonable amount of time to troubleshoot and repair the system.

The Main Steam Bypass Valves (MSBV) are motor operated valves that provide the capability to warm the main steam lines and to equalize the steam pressure across the associated MSIV during unit startup. The MSBVs are normally closed during power operation and close on a Main Steam Isolation signal if open. The MSIVs and their associated MSBVs are **NOT** Containment Isolation Valves. The Main Steam Check Valves (MSCV) automatically close on reverse flow for a main steam line break upstream of the MSIVs.

While the MSBVs and MSCVs support the Main Steam Isolation function, no Technical Specification Limiting Condition for Operation or Action applies to them.

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3/4.7.1.6 Standby Steam Generator Feedwater System

The purpose of this specification and the supporting surveillance requirements is to assure operability of the non-safety grade Standby Steam Generator Feedwater System. The Standby Steam Generator Feedwater System consists of commercial grade components designed and constructed to industry and FPL standards of this class of equipment located in the outdoor plant environment typical of FPL facilities system wide. The system is expected to perform with high reliability, i.e., comparable to that typically achieved with this class of equipment. FPL intends to maintain the system in good operating condition with regard to appearance, structures, supports, component maintenance, calibrations, etc.

The function of the Standby Feedwater System for OPERABILITY determinations is that it can be used as a backup to the Auxiliary Feedwater (AFW) System in the event the AFW System does **NOT** function properly. The system would be manually started, aligned, and controlled by the operator when needed.

The A pump is electric-driven and is powered from the non-safety related C bus. In the event of a coincident loss of offsite power, the B pump is diesel driven and can be started and operated independent of the availability of on-site or off-site power.

A supply of 77,000 gallons from the Demineralized Water Storage Tank for the Standby Steam Generator Feedwater Pumps is sufficient water to remove decay heat from the reactor for six (6) hours for a single unit or two (2) hours for two units. This was the basis used for requiring 77,000 gallons of water in the non-safety grade Demineralized Water Storage Tank and is judged to provide sufficient time for restoring the AFW System or establishing make-up to the Demineralized Water Storage Tank.

The minimum indicated volume (145,000 gallons) consists of an allowance for level indication instrument uncertainties (approximately 15,000 gallons) for water deemed unusable because of tank discharge line location and vortex formation (approximately 50,200 gallons) and the minimum usable volume (77,000 gallons). The minimum indicated volume corresponds to a water level of 9.2 feet in the Demineralized Water Storage Tank.

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The Standby Steam Generator Feedwater Pumps are **NOT** designed to NRC requirements applicable to Auxiliary Feedwater Systems and **NOT** required to satisfy Design Basis Events requirements. These pumps may be out of service for up to 24 hours before initiating formal notification because of the extremely low probability of a demand for their operation.

The guidelines for NRC notification in case of both pumps being out of service for longer than 24 hours are provided in applicable plant procedures, as a voluntary 4 hour notification.

Adequate demineralized water for the Standby Steam Generator Feedwater system will be verified in accordance with the Surveillance Frequency Control Program. The Demineralized Water Storage Tank provides a source of water to several systems and therefore, requires daily verification.

The Standby Steam Generator Feedwater Pumps will be verified OPERABLE by starting and operating them in the recirculation mode. Also, each Standby Steam Generator Feedwater Pump will be started and aligned to provide flow to the nuclear unit's steam generators. The surveillance frequencies are controlled under the Surveillance Frequency Control Program.

This surveillance regimen will thus demonstrate operability of the entire flow path, backup non-safety grade power supply and pump associated with a unit at least each refueling outage. The pump, motor driver, and normal power supply availability would typically be demonstrated by operation of the pumps in the recirculation mode monthly on a staggered test basis.

The diesel engine driver for the B Standby Steam Generator Feedwater Pump will be periodically verified operable. In addition, an inspection will be performed on the diesel in accordance with procedures prepared in conjunction with its manufacture's recommendations for the diesel's class of service. The surveillance frequencies are controlled under the Surveillance Frequency Control Program. This inspection will ensure that the diesel driver is maintained in good operating condition consistent with FPL's overall objectives for system reliability.

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3/4.7.1.7 Feedwater Isolation

The Feedwater Control Valves (FCVs) isolate Main Feedwater (MFW) flow to the secondary side of the steam generators following a Steam Line Break (SLB) inside containment. The function of the non-safety-grade Feedwater Isolation Valves (FIVs) is to provide the second isolation of MFW flow to the secondary side of the Steam Generators following a SLB. Closure of the FCVs, FIVs, and the tandem bypass line valves terminate flow to the Steam Generators for Feedwater Line Breaks (FWLBs) occurring upstream of the FCVs or FIVs.

The LCO requires Main Feedwater Isolation be OPERABLE. Main Feedwater Isolation consists of the three FCVs, three FIVs, six bypass line isolation valves, and their associated isolation circuits. This LCO ensures that in the event of an SLB inside containment, a single failure can **NOT** result in continued MFW flow into the containment. Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB inside Containment.

In MODES 1, 2, and 3, the FCVs and FIVs and the bypass lines valves are required to be OPERABLE to limit the amount of available fluid added to containment in a SLB inside containment. In MODES 4, 5, and 6, Steam Generator energy is low and FW isolation is **NOT** required.

The ACTION Statements are modified by a Note indicating that separate Condition entry is allowed for each valve.

With one FCV, FIV or Bypass Valve in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE FIV and tandem bypass line isolation valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

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3/4.7.1.7 (Continued)

Inoperable FCVs and FIVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable in view of valve status indications available in the Control Room, and other administrative controls, to ensure that these valves are closed or isolated.

With two valves in the same flow path inoperable, there may be **NO** redundant system to operate automatically and perform the required safety function. Although the Containment can be isolated with the failure of two valves in parallel in the same flow path, the double failure can be an indication of a common mode failure in the valves of this flow path, and as such, is treated the same as a loss of the isolation capability of this flow path. Under these conditions, affected valves in each flow path must be restored to OPERABLE status, or the affected flow path isolated within 8 hours. This action returns the system to the condition where at least one valve in each flow path is performing the required safety function. The 8 hour Completion Time is reasonable, based on operating experience, to complete the actions required to close the FCV or FIV, or otherwise isolate the affected flow path.

SR 4.7.1.7.a verifies that each FCV, FIV, and bypass line valve will actuate to its isolation position on an actuation or simulated actuation signal. The frequency is based on the potential for an unplanned transient if the surveillance were performed with the reactor at power. The surveillance frequency is controlled under the Surveillance Frequency Control Program. Operating experience has shown that these components usually pass this surveillance.

SR 4.7.1.7.b verifies that the closure time of each FCV, FIV, and bypass line valve, when tested in accordance with the Inservice Testing Program, is within the limits assumed in the accident and containment analyses. This SR is normally performed upon returning the unit to operation following a refueling outage. These valves should **NOT** be tested at power, since even a part stroke exercise increases the risk of a valve closure with the unit generating power. This is consistent with the ASME Code Section XI (Ref. 3), quarterly stroke requirements during operation in MODES 1 and 2.

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3/4.7.2 Component Cooling Water System

During MODES 1, 2, 3, and 4, the OPERABILITY of the Component Cooling Water System ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single active failure, is consistent with the assumptions used in the safety analyses. One pump and two heat exchangers provide the heat removal capability for accidents that have been analyzed.

The third safety related D switchgear, utilized as a swing bus, and manually aligned to either the A or B 4.16 kV bus of its respective unit is considered an extension of that power supply bus. The third (C) CCW pump of each unit, when powered from its associated unit's D bus, may be utilized to provide the T.S. independent power supply operability requirement when a pump is out of service. The most limiting single active failure considered was the loss of one diesel, which results in only one required CCW pump starting automatically to mitigate the consequences of the MHA. However, the C pump is interlocked, and for a start signal to initiate on a loss of offsite power or safety injection signal, the supply breaker for the A or B CCW pump (associated with the A or B 4kV Bus to which it is aligned) must be OPEN and RACKED OUT. Technical Specification ACTION statements may be invoked for **NOT** ensuring that the second operable pump is powered from an independent safety related bus.

During MODES 5 and 6, the Component Cooling Water System has no OPERABILITY requirements (Reference AR 01744253 CE). During these MODES, the Component Cooling Water System is required to be functional, or capable of performing its specified function.

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3/4.7.3 Intake Cooling Water System

During MODES 1, 2, 3, and 4 the OPERABILITY of the Intake Cooling Water System ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The design and operation of this system, assuming a single active failure, ensures cooling capacity consistent with the assumptions used in the safety analyses. The supply headers are redundant, but the return merges to a non-redundant discharge header that returns water to the discharge canal. The redundant ICW supply headers addresses the design for passive failure.

The third safety related D switchgear, utilized as a swing bus, and manually aligned to either the A or B 4.16 kV bus of its respective unit is considered an extension of that power supply bus. The third (C) ICW pump of each unit, when powered from its associated unit's D bus, may be utilized to provide the T.S. independent power supply operability requirement when a pump is out of service. The most limiting single active failure considered was the loss of one diesel, which results in only one required ICW pump starting automatically to mitigate the consequences of the MHA. However, the C pump is interlocked, and for a start signal to initiate on a loss of offsite power or safety injection signal, the supply breaker for the A or B ICW Pump (associated with the A or B 4kV Bus to which it is aligned) must be OPEN and RACKED OUT. Technical Specification ACTION statements may be invoked for **NOT** ensuring that the second operable pump is powered from an independent safety related bus.

During MODES 5 and 6, the Intake Cooling Water System has **NO** OPERABILITY requirements (Reference AR 01744253 CE). During these MODES, the Intake Cooling Water System is required to be functional or capable of performing its specified function.

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3/4.7.4 Ultimate Heat Sink

The limit on Ultimate Heat Sink (UHS) temperature in conjunction with the surveillance requirements of Technical Specification 3/4.7.2 will ensure that sufficient cooling capacity is available either: (1) To provide normal cooldown of the facility, or (2) To mitigate the effects of accident conditions within acceptable limits.

FPL has the option of monitoring UHS temperature by monitoring the temperature in the ICW System piping going to the inlet of the CCW Heat Exchangers. Monitoring UHS temperature after the ICW Pumps, but prior to CCW Heat Exchangers is considered to be equivalent to temperature monitoring before the ICW Pumps. The supply water leaving the ICW Pumps will be mixed, and therefore, it will be representative of the bulk UHS temperature to the CCW Heat Exchanger inlet. The effects of pump heating on the supply water are negligible due to low ICW head and high water volume. Accordingly, monitoring UHS temperature after the ICW Pumps, but prior to the CCW Heat Exchangers provides an equivalent location for monitoring UHS temperature.

With the implementation of the CCW Heat Exchanger Performance Monitoring Program, the limiting UHS temperature can be treated as a variable with an absolute upper limit of 104°F without compromising any margin of safety. Demonstration of actual heat exchanger performance capability supports system operation with postulated canal temperatures greater than 104°F. Therefore, an upper Technical Specification limit of 104°F is conservative.

The frequency of verifying UHS water temperature to ensure the limit of 104ºF is **NOT** exceeded when the water temperature is less than 100ºF is controlled under the Surveillance Frequency Control Program as there is ample (greater than or equal to 4ºF) margin to the limit. Due to daily variations in temperature, when UHS water temperature exceeds 100ºF the water temperature shall be verified at least once per hour to ensure that Cooling Canal System temperature variations are appropriately captured, thus ensuring the Technical Specification limit is **NOT** exceeded.

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For the verification of UHS average supply water temperature, an appropriate instrument uncertainty will be subtracted from the Acceptance Criteria to ensure the Technical Specification limit is **NOT** exceeded.

3/4.7.5 Control Room Emergency Ventilation System

The OPERABILITY of the Control Room Emergency Ventilation System (CREVS) ensures that: (1) The ambient air temperature does **NOT** exceed the allowable temperature for continuous duty rating for the equipment and instrumentation cooled by this system, and (2) The Control Room envelope (CRE) will remain habitable for occupants during and following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. The OPERABILITY of this system in conjunction with Control Room design provisions is based on limiting the radiation exposure to personnel occupying the CRE to 5 rem Total Effective Dose Equivalent (TEDE) for the duration of the accident. The radiological limits are consistent with the requirements of 10 CFR Part 50.67. CRE occupants are protected from chemical hazards in accordance with the limits of Regulatory Guide 1.78.

The Control Room Emergency Ventilation System (CREVS) is considered to be OPERABLE (Ref: JPN_PTN_SENP-92-017) when:

1) Three Air Handling Units (AHUs) (three out of three) are OPERABLE,
2) Two Condensing (air conditioning (A/C)) Units (two out of three) are OPERABLE,
3) Two Recirculation Fans are OPERABLE,
4) Two Recirculation Dampers are OPERABLE,
5) One Recirculation Filter unit is OPERABLE,
6) Two Normal Outside Air Intake Dampers are OPERABLE,
7) Two Emergency Outside Air Intake Dampers are OPERABLE,

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The reason three AHUs are required is that in the event of a single failure, only two AHUs would be available to supply air to the suction of the recirculation filter and fan. This is the configuration tested to support Technical Specification operability for flow through the Emergency Charcoal Filter Unit. Taking one AHU out of service renders the system incapable of operating in accordance with the tested configuration assuming an accident and a single failure, i.e., only one air handling unit available instead of the two assumed in the analysis. Any one of the three condensing (A/C) units is capable of maintaining Control Room equipment within environmental limits for temperature and humidity. Thus, one condensing unit can be taken out of service without impacting the ability of CREVS to accomplish its intended function under single failure conditions.

The LCO actions allow inoperability of the redundant active CREVS components (one AHU, two Condensing Units, one Recirculation Fan, one Recirculation Damper, one Normal Outside Air Intake Damper, and/or one Emergency Outside Air Intake Damper) for a period of up to 7 days (30 days for two inoperable condensing units) consistent with the approach provided in the Westinghouse Standard Technical Specifications and based on the low probability of occurrence of a Design Basis Accident (DBA) challenging the Control Room Habitability during this time period and the continued capability of the remaining operable system components to perform the required CREVS safety function. In effect, this temporarily suspends the single failure criterion for the affected components while assuring the continued functionality of the system. The kitchen and toilet area exhaust ventilation ducts have been permanently blocked off with seismic Class 1 solid plates coated in accordance with SPEC-C-004. The kitchen and toilet area motor operated and gravity backdraft dampers are no longer credited for CREVS operability.

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When one damper in the Normal Outside Air Intake is inoperable, it can either be restored within 7 days or one of the two in-series dampers CLOSED and CREVS run in RECIRCULATION Mode. When one Recirculation Damper is inoperable, it can either be restored within 7 days or one of the two paralleled dampers OPENED and the CREVS run in RECIRCULATION Mode. Indefinite operation in the RECIRCULATION Mode is allowed since the CREVS safety function is being met. With one or both Emergency Outside Air Intake Dampers inoperable, they can either be restored within 7 days or opened without adversely impacting the NORMAL or EMERGENCY Mode of operation. Indefinite operation is allowed with an opened Emergency Outside Air Intake Damper since the CREVS is capable of performing its safety function. (See TSA 03-03-025-024 for evaluation). The placement of the dampers in their “fail-safe” position in lieu of restoration is allowed as the dampers fail “as-is” in the event of loss of offsite power (except for the emergency outside air intake dampers which go to their emergency OPEN position) and are in their EMERGENCY Mode position in the event of receipt of an emergency actuation signal. The 7 day allowable outage time for an inoperable Normal Outside Air Intake damper, Recirculation damper or Emergency Outside Air Intake damper is consistent with the approach provided in the Westinghouse Standard Technical Specifications for a single operable CREVS train.

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When the filter train is inoperable for reasons other than an inoperable CRE boundary, e.g., the filter is inoperable, and/or two recirculation fans are inoperable, and/or two recirculation dampers are inoperable, all movement of irradiated fuel is required to be immediately suspended and use of the Compensatory Filtration Unit is required to be immediately initiated and proper operation verified within 24 hours, ensuring Control Room occupant radiological exposures will **NOT** exceed limits. Within 7 days, the inoperable filter train is required to be restored to OPERABLE status. Consistent with 0-ADM-211 and NUREG-1431, "immediately" indicates that the required action should be pursued without delay and in a controlled manner, i.e., placing the Compensatory Filtration Unit into service should be initiated within approximately one hour. The 24 hour allowance to verify proper operation is reasonable based on the low probability of a DBA occurring during this time period. The 7 day AOT is reasonable based on the verification that the Compensatory Filtration Unit will continue to provide the CREVS safety function. As with the active components, this has the effect of temporarily suspending the single failure criterion for the affected components while assuring the continued functionality of the system. The 7 day AOT is also a reasonable time to diagnose, plan, repair, and test most problems with the inoperable filter train.

The compensatory filtration unit is designed as a manual, safety-related, Seismic Class I backup to the installed system with the same functional and operational capabilities as the installed filter train. In addition, the unit is surveillance tested in accordance with the same requirements as those imposed on the installed filter train per TS 4.7.5.b, c, and d except that the requirements of TS 4.0.1 – 4.0.4 do **NOT** apply to the compensatory unit as it is **NOT** included in CREVS LCO.

Regarding exposure of the filters to effluents that may have an adverse effect on the functional capability of the system, painting, fire, or chemical releases are considered "**NOT** communicating" with the HEPA filter or adsorber if the system is **NOT** in operation, the isolation dampers for the system are closed, and there is **NO** pressure differential across the filter housing. This provides reasonable assurance that air is **NOT** passing through the filters and adsorbers.

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In addition, the CREVS includes the Emergency Outside Air Intakes, located beyond the southeast and northeast corners of the Auxiliary Building. The CREVS Emergency Outside Air Intakes are considered OPERABLE when: 1) both flow paths are available, 2) have balanced intake flow rates and 3) a flow path capable of drawing outside makeup air from only the analyzed intake locations. The Alternative Source Term radiological analyses assume both emergency outside air intake flow paths are available with parallel dampers ensuring outside makeup air can be drawn through both intake locations during a design basis accident and a single active failure. These analyses rely on a provision in Regulatory Guide 1.194 Section 3.3.2 that allows a reduction in the atmospheric dispersion factors (X/Qs) for dual intake arrangements with balanced flow rates to one half of the more limiting X/Q value provided the two intakes are **NOT** within the same wind direction window for each release / receptor location. Accordingly, any maintenance on the emergency outside intake dampers or associated duct work that would prevent the CREVS from accomplishing these functions would require entering action statement a.7. The provisions of LCO 3.0.6 apply to the surveillance testing required to demonstrate operability of the emergency intake flow paths.

System components are **NOT** subject to rapid deterioration, having lifetimes of many years, even under continuous flow conditions. Visual inspection and operating tests provide assurance of system reliability and will ensure early detection of conditions which could cause the system to fail or operate improperly. The filters performance tests prove that filters have been properly installed, that **NO** deterioration or damage has occurred, and that all components and subsystems operate properly. The in-situ tests are performed in accordance with the methodology and intent of ANSI N510 (1975) and provide assurance that filter performance has **NOT** deteriorated below returned specification values due to aging, contamination, or other effects. Charcoal samples are tested using ASTM D3803-1989 in accordance with Generic Letter 99-02. The test conditions (30°C and 95% relative humidity) are as specified in the Generic Letter. Table 1 of the ASTM standard provides the tolerances that must be met during the test for each test parameter. The specified methyl iodide penetration value is based on the assumptions used in the LOCA Analysis.

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Units 3 and 4 share a common CRE. The CRE is the area within the confines of the CRE boundary that contains the spaces that Control Room occupants inhabit to control the units during normal and accident conditions. This area encompasses the Control Room, including the Control Room offices, rack area, kitchen, and lavatory, and mechanical equipment room located below the Control Room which contains the CREVS equipment. The CRE is protected during normal operation, natural events, and accident conditions. The CRE Boundary is the combination of walls, floor, roof, ducting, doors, penetrations, and equipment that physically form the CRE. The operability of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will **NOT** exceed the inleakage assumed in the radiological dose consequence analyses and that CRE occupants are protected from hazardous chemicals and smoke. The CRE and its boundary are defined in Control Room Envelope Habitability Program.

The location of CREVS components and ducting within the CRE ensures an adequate supply of filtered air to all areas requiring access. CREVS provides airborne radiological protection for the CRE occupants, as demonstrated by radiological dose consequence analyses for the most limiting design basis accident presented in UFSAR Chapter 14. CREVS also provides protection from chemical hazards and smoke hazards. CREVS pressurizes the CRE relative to external areas adjacent to the CRE boundary. The analysis of hazardous chemical releases for NUREG-0737 Item III.D.3.4, “Control Room Habitability Requirement,” and the subsequent reanalysis included in PC/M 06-004, “Addition of Unit 5 to the Turkey Point Site,” for new chemical release hazards demonstrate that the toxicity limits of Regulatory Guide 1.78 are **NOT** exceeded in the CRE following a hazardous chemical release. Thus, neither automatic nor manual actuation of CREVS is required for an analyzed hazardous chemical release. Analysis of a smoke challenge demonstrates that it will **NOT** result in the inability of the CRE occupants to control the reactors either from the Control Room or alternate shutdown panels.

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3/4.7.5 (Continued)

In order for the CREVS to be considered OPERABLE, the CRE Boundary must be maintained such that the CRE occupant radiological dose does **NOT** exceed that calculated in the DBA Radiological Dose Consequence Analyses and CRE occupants are protected from hazardous chemicals and smoke. Since the CREVS and CRE are common to both units, the ACTION requirements are applicable to both units simultaneously, and must be applied according to each unit's operational MODE.

The LCO is modified by a Note that allows the CRE boundary to be opened intermittently under administrative controls. This Note applies only to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the Control Room operators. The dedicated individual should have a method to rapidly close the opening and restore the integrity of the CRE boundary when a need for CRE isolation is indicated.

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3/4.7.5 (Continued)

If the unfiltered inleakage of potentially contaminated air past the CRE Boundary and into the CRE can result in CRE occupant radiological dose greater than that calculated in the dose analyses or in inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Upon determination that the CRE boundary is inoperable in MODES 1, 2, 3, or 4, the operators are required to immediately initiate action to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will **NOT** exceed the calculated dose in the radiological dose consequence analyses, and that CRE occupants are protected from hazardous chemicals and smoke. Previous surveys of offsite and onsite chemicals identified that **NO** hazardous chemicals present a hazard to Control Room habitability. Thus, the mitigating action for chemical hazards may verify that the chemical hazards analyses are current and require **NO** toxic gas protection for the CRE occupants. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) during MODES 1, 2, 3 and 4 should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour allowable outage time (AOT) is reasonable based on the low probability of a DBA occurring during this time period and the use of mitigating actions. Once the effectiveness of the mitigating actions have been verified within 24 hours of CRE boundary inoperability, actions must be taken to restore the CRE boundary to OPERABLE within 90 days. The 90 day AOT is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactors and maintain them in a safe shutdown condition in the event of a DBA. The 90 day AOT is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

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3/4.7.5 (Continued)

In MODES 1, 2, 3, or 4, if the inoperable CREVS or the CRE Boundary cannot be restored to OPERABLE status within the associated required AOT, the unit must be placed in a MODE that minimizes the accident risk. To achieve this status, the unit must be placed in at least MODE 3 (HOT STANDBY) within 6 hours, and in MODE 5 (COLD SHUTDOWN) within the following 30 hours. If the inoperability applies to both units simultaneously, be in MODE 3 within 12 hours, and in MODE 5 within the following 30 hours. The AOTs are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

Upon determination that the CRE boundary is inoperable in MODES 5, 6, or during the movement of irradiated fuel, all movement of irradiated fuel must be immediately suspended and must remain suspended for the duration of inoperability. Suspending irradiated fuel movement during these operational modes suspends activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does **NOT** preclude the movement of fuel to a safe position. These ACTION requirements apply to both units simultaneously.

Operations that, in the absence of a compensation adjustment, add positive reactivity are acceptable when, combined with other concurrent actions that add negative reactivity, the overall net reactivity addition is zero or negative. For example, a positive reactivity addition caused by temperature increases or decreases is acceptable if it is concurrent with a negative reactivity addition (i.e., boration and/or rod movement, if authorized) such that the overall, net reactivity addition is zero or negative.

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3/4.7.5 (Continued)

Surveillance Requirement (SR) 4.7.5.f verifies the OPERABILITY of the CRE Boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. It verifies that the unfiltered air inleakage into the CRE is **NO** greater than the flow rate assumed in the dose analyses. When unfiltered air inleakage is greater than the assumed flow rate, ACTION b must be entered. For MODES 1, 2, 3 or 4, ACTION b allows 90 days to restore the CRE boundary to OPERABLE status provided immediate action is initiated to implement mitigating actions, and within 24 hours, the mitigating actions are verified to ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. For MODES 5, 6 or during the movement of irradiated fuel, ACTION b requires the immediate suspension of all irradiated fuel movement and the suspension remains in effect for the duration of CRE boundary inoperability. The details of the testing are specified in the Control Room Envelope Habitability Program.

3/4.7.6 Snubbers

All snubbers are required OPERABLE to ensure that the structural integrity of the Reactor Coolant System and all other safety-related systems is maintained during and following a seismic or other event initiating dynamic loads. Snubbers are demonstrated OPERABLE by performance of the Snubber Testing Program.

When a snubber is found inoperable, an evaluation is performed in accordance with the Snubber Testing Program to determine the mode of failure, and if any Safety Related System or component has been adversely affected by the inoperability of the snubber. The evaluation shall determine whether or **NOT** the snubber mode of failure has imparted a significant effect or degradation on the supported component or system.

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3/4.7.7 Sealed Source Contamination

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(a)(3) limits for plutonium. This limitation will ensure that leakage from Byproduct, Source, and Special Nuclear Material sources will **NOT** exceed allowable intake values.

Sealed Sources are classified into three groups according to their use, with Surveillance Requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are **NOT**. Sealed sources which are continuously enclosed within a shielded mechanism (i.e., sealed sources within radiation monitoring or boron measuring devices) are considered to be stored and need **NOT** be tested unless they are removed from the shielded mechanism.

3/4.7.8 Explosive Gas Mixture

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the Gas Decay Tank System (as measured in the Inservice Gas Decay Tank) is maintained below the flammability limits of hydrogen and oxygen. Maintaining the concentration of hydrogen and oxygen below their flammability limits provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50.

3/4.7.9 Gas Decay Tanks

The tanks included in this specification are those tanks for which the quantity of radioactivity contained is **NOT** limited directly or indirectly by another Technical Specification. Restricting the quantity of radioactivity contained in each Gas Decay Tank provides assurance that in the event of an uncontrolled release of the tank's contents, the resulting whole body exposure to a MEMBER OF THE PUBLIC at the nearest SITE BOUNDARY will **NOT** exceed 0.1 rem.

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3/4.8 Electrical Power Systems

3/4.8.1
3/4.8.2
&
3/4.8.3 A.C. Sources, D.C. Sources, and Onsite Power Distribution

The OPERABILITY of the A.C. and D.C power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety-related equipment required for (1) The safe shutdown of the facility, and (2) The mitigation and control of accident conditions within the facility.

The loss of an associated diesel generator for systems, subsystems, trains, components or devices does **NOT** result in the systems, subsystems, trains, components or devices being considered inoperable for the purpose of satisfying the requirements of its applicable Limiting Condition for Operation for the affected unit provided (1) Its corresponding normal power source is OPERABLE; and (2) Its redundant systems, subsystems, trains, components, and devices that depend on the remaining OPERABLE diesel generators as a source emergency power to meet all applicable LCOs are OPERABLE. This allows operation to be governed by the time limits of the ACTION statement associated with the inoperable diesel generator, **NOT** the individual ACTION statements for each system, subsystem, train, component, or device. However, due to the existence of shared systems, there are certain conditions that require special provisions. These provisions are stipulated in the appropriate LCOs as needed.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

More specifically, LCOs 3.5.2 and 3.8.2.1 require that associated EDGs be OPERABLE in addition to requiring that Safety Injection Pumps, battery chargers, and battery banks, respectively also be OPERABLE. This EDG requirement was placed in these particular LCOs due to the shared nature of these systems to ensure adequate EDG availability for the required components. A situation could arise where a unit in MODES 1, 2, 3, or 4 could be in full compliance with LCO 3.8.1.1, yet be using shared equipment that could be impacted by taking an EDG out-of-service on the opposite unit. In this situation, Diesel Generator ACTION 3.8.1.1.d which verifies redundant train OPERABILITY, may **NOT** be applicable to one of the units. Thus, specific requirements for EDG OPERABILITY have been added to the appropriate LCOs of the shared systems (3.5.2 and 3.8.2.1). It is important to note that in these particular LCOs, the inoperability of a required EDG does **NOT** constitute inoperability of the other components required to be OPERABLE in the LCO. Specific ACTION Statements are included in 3.5.2 and 3.8.2.1 for those situations where the required components are OPERABLE (by the definition of OPERABILITY) but **NOT** capable of being powered by an OPERABLE EDG.

The ACTION requirements specified for the levels of degradation of the power sources provide restrictions upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources is consistent with the initial condition assumptions of the safety analysis and is based upon maintaining adequate onsite A.C. and D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss-of-offsite power and single failure of one onsite A.C. source. Two physically independent A.C. circuits exist between the offsite transmission network and the onsite Class 1E Distribution System by utilizing the following:

(1) A total of nine transmission lines which lead to six separate transmission substations tie the Turkey Point Switchyard to the offsite power grid;

(2) Two dual-winding startup transformers each provide 100% of the A and B train 4160 volt power from the switchyard to its associated unit.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

In addition, each Startup Transformer has the capability to supply backup power of approximately 2500 kw to the opposite unit's A-train 4160 volt bus. Two Emergency Diesel Generators (EDG) provide onsite emergency A.C. power for each unit. EDGs 3A and 3B provide Unit 3 A-train, and B-train emergency power, respectively. EDGs 4A and 4B provide Unit 4 A train and B-train emergency power, respectively.

Due to the shared nature of numerous electrical components between Turkey Point Units 3 & 4, the inoperability of a component on an associated unit will often affect the operation of the opposite unit. These shared electrical components consist primarily of both Startup Transformers, three out of four 4160 volt busses, and associated 480 volt Motor Control Centers, all four 125 volt D.C. busses, all eight 120 volt Vital A.C. panels and eight out of twelve Vital A.C. Inverters, four out of eight battery chargers, and all four battery banks. Depending on the components which is (are) determined inoperable, the resulting ACTION can range from the eventual shutdown of the opposite unit long after the associated unit has been shutdown (30 days) to an immediate shutdown of both units. Therefore, ACTION times allow for an orderly sequential shutdown of both units when the inoperability of a components affects both units with equal severity. When a single unit is affected, the time to be in HOT STANDBY is 6 hours. When an ACTION statement requires a dual unit shutdown, the time to be in HOT STANDBY is 12 hours. This is to allow the orderly shutdown of one unit at a time and **NOT** jeopardize the stability of the electrical grid by imposing a dual unit shutdown.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

As each Startup Transformer only provides the limited equivalent power of approximately one EDG to the opposite unit's A-train 4160 volt bus, the allowable out-of-service time in TS 3.8.1.1, ACTION 'a' of 30 days has been applied before the opposite unit is required to be shutdown. A unit with an inoperable Startup Transformer or associated circuit can either reduce THERMAL POWER to less than or equal to 30% RATED THERMAL POWER within 24 hours and remain operating at reduced power for up to 30 days until the Startup Transformer and associated circuit is restored to OPERABLE status, or restore the inoperable Startup Transformer and associated circuit to OPERABLE status within the next 48 hours. If power is **NOT** reduced and the Startup Transformer and associated circuit is **NOT** restored to OPERABLE status within 72 hours of the discovery of inoperability, the unit must be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. If power is reduced and the Startup Transformer and associated circuit is **NOT** restored to OPERABLE status within 30 days of the discovery of inoperability, the unit must be in HOT STANDBY within the next 12 hours and in COLD SHUTDOWN within the following 30 hours. The 30% RATED THERMAL POWER limit was chosen because at this power level the decay heat and fission product production has been reduced and the operators are still able to maintain automatic control of the Feedwater Trains and other unit equipment. At lower power levels, the operators must use manual control with the Feedwater Bypass lines. By **NOT** requiring a complete unit shutdown, the plant avoids a condition requiring natural circulation and avoids intentionally relying on engineered safety features for non-accident conditions.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

With one startup transformer and one of the three required EDGs inoperable, TS 3.8.1.1, ACTION ‘c’ applies. The unit with the inoperable transformer can either reduce THERMAL POWER to less than or equal to 30% RATED THERMAL POWER within 24 hours and remain operating at reduced power until the Startup Transformer is restored to OPERABLE status provided the inoperable EDG is made OPERABLE within 72 hours, or restore the inoperable Startup Transformer to OPERABLE status within the next 48 hours. If power is **NOT** reduced and the Startup Transformer is **NOT** restored to OPERABLE status within 72 hours of the discovery of inoperability, the unit must be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. TS 3.8.1.1, ACTION 'a', 'b', and 'c' apply concurrently until ACTION 'c' is exited by restoring a Startup Transformer or EDG to OPERABLE status. Because ACTION 'c' invokes ACTION 'a' it also applies to a Startup Transformer's inoperable associated circuit. The notification of a loss of Startup Transformers to the NRC (ACTION STATEMENT 3.8.1.1.c) is **NOT** a 10 CFR 50.72/50.73 requirement and as such will be made for information purposes only to the NRC Operations Center via commercial lines.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

With an EDG out of service, ACTION statement 3.8.1.1.b and Surveillance Requirement (SR) 4.8.1.1.1.a are provided to demonstrate operability of the required Startup Transformers and their associated circuits within 1 hour and at least once per 8 hours thereafter. For a planned EDG inoperability, SR 4.8.1.1.1.a may be performed up to 1 hour prior to rendering the EDG inoperable. The frequency of SR 4.8.1.1.1.a after it has been performed once, is at least once per 8 hours until the EDG is made operable again. When one diesel generator is inoperable, there is also an additional ACTION requirement to verify that required systems, subsystems, trains, components, and devices that depend on the remaining required OPERABLE diesel generators as a source of emergency power to meet all applicable LCOs, are OPERABLE. This requirement is intended to provide assurance that a loss-of-offsite power event will **NOT** result in a complete loss of safety function of critical systems during the period one of the diesel generators is inoperable. This requirement allows continued operation to be governed by the time limits of the ACTION statement associated with the inoperable diesel generator. The loss of a diesel generator does **NOT** result in the associated systems, subsystems, trains, components, or devices being considered inoperable provided: (1) Its corresponding normal power source is OPERABLE, and (2) Its redundant systems, subsystems, trains, components, and devices that depend on the remaining required OPERABLE diesel generators as a source of emergency power to meet all applicable LCOs, are OPERABLE.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

All diesel generator inoperabilities must be investigated for Common Cause Failures regardless of how long the diesel generator inoperability persists. When one diesel generator is inoperable, TS 3.8.1.1 ACTION statements b and c provide an allowance to avoid unnecessary testing of other required diesel generators. If it can be determined that the cause of the inoperable diesel generator does **NOT** exist on the remaining required diesel generators, then SR 4.8.1.1.2a.4 does **NOT** have to be performed. Twenty-four (24) hours (or eight (8) hours if both a Startup Transformer and diesel generator are inoperable) is reasonable to confirm that the remaining required diesel generators are **NOT** affected by the same problem as the inoperable diesel generator. When an EDG itself is inoperable (**NOT** including a support system or independently testable component), the other EDGs should be tested once unless the absence of any potential common-mode failure can be demonstrated. If it cannot otherwise be determined that the cause of the initial inoperable diesel generator does **NOT** exist on the remaining required diesel generators, then satisfactory performance of SR 4.8.1.1.2a.4 suffices to provide assurance of continued OPERABILITY of the remaining required diesel generators. If the cause of the initial inoperability exists on one or more of the remaining required diesel generators, those diesel generators affected would also be declared inoperable upon discovery, and TS 3.8.1.1 ACTION statement f or TS 3.0.3, as appropriate, would apply.

When in Modes 1, 2, 3 or 4, a unit depends on one EDG and its associated train of busses from the opposite unit in order to satisfy the single active failure criterion for safety injection (SI) pumps and other shared equipment required during a loss-of-coolant accident with a loss-of-offsite power. Therefore, one EDG from the opposite unit is required to be OPERABLE along with the two EDGs associated with the applicable unit.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

For single unit operation (one unit in MODES 1-4 and one unit in Modes 5-6 or defueled) TS 3.8.1.1 ACTION d. refers to one of the three required Emergency Diesel Generators. For dual unit operation (both units in MODES 1-4), TS 3.8.1.1 ACTION d. refers to one of the four required Emergency Diesel Generators. This conclusion is based on the portion of ACTION d. that states "in addition to ACTION b. or c" Since ACTIONs b. and c. both refer to one of the required diesel generators, this implies that ACTION d. also refers to one of the required diesel generators. ACTION d. says "in addition to ACTION b. or c. above, ..." therefore, ACTION d. is merely providing additional requirements applicable to the conditions that required satisfaction of ACTIONs b. or c.

With both Startup Transformers inoperable, the units are required to be shutdown consecutively, after 24 hours. A consecutive shutdown is used because a unit without its associated transformer must perform a natural circulation cooldown. By placing one unit in COLD SHUTDOWN before starting shutdown of the second unit, a dual unit natural circulation cooldown is avoided.

The term verify means to administratively check by examining logs or other information to determine if required components are out-of-service for maintenance or other reasons. It does **NOT** mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

In accordance with Technical Specification Amendments 215/209 during MODES 1, 2, and 3, if an EDG is to be removed from service for maintenance for a period scheduled to exceed 72 hours, the following restrictions apply:

If an EDG is unavailable, the Startup Transformer will be removed from service only for corrective maintenance, i.e., maintenance required to ensure or restore operability.

If the Startup Transformer is unavailable, an EDG will be removed from service only for corrective maintenance, i.e., maintenance required to ensure or restore operability.

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If an EDG is unavailable, an EDG on the opposite unit will be removed from service only for corrective maintenance, i.e., maintenance required to ensure or restore operability.

If the Blackout Crosstie is unavailable, an EDG will be removed from service only for corrective maintenance, i.e., maintenance required to ensure or restore operability.

If an EDG is unavailable, the Blackout Crosstie will be removed from service only for corrective maintenance, i.e., maintenance required to ensure or restore operability.

If a condition is entered in which both an EDG and the Blackout Crosstie are unavailable at the same time, restore the EDG or Blackout Crosstie to service as soon as possible.

If a hurricane warning has been issued in an area which may impact the FPL grid, i.e., within the FPL service area, an EDG or the Blackout Crosstie should be removed from service only for corrective maintenance, i.e., maintenance required to ensure or restore operability.

If an EDG or the Blackout Crosstie is unavailable when a hurricane warning in an area that may impact the FPL grid is issued, the unavailable components will be restored to service as soon as possible.

If a tornado watch has been issued for an area which includes the Turkey Point Plant site, and/or the substations and transmission lines serving Turkey Point Plant switchyard, restore the unavailable components to service as soon as possible.

To address the potential fire risk implications during MODES 1, 2, and 3, if an EDG is to be removed from service for maintenance for a period scheduled to exceed 72 hours, the following actions will be completed:

A plant fire protection walkdown of the areas that could impact EDG availability, offsite power availability or the ability to use the Station Blackout Crosstie prior to entering the extended allowed outage time (AOT).

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

A thermographic examination of high-risk potential ignition sources in the Cable Spreading Room and the Control Room,

Restriction of planned hot work in the Cable Spreading Room and Control Room during the extended AOT, and

Establishment of a continuous fire watch in the Cable Spreading Room when in the extended AOT.

In addition to the predetermined restrictions, assessments performed in accordance with the provisions of the Maintenance Rule (a)(4) will ensure that any other risk significant configurations are identified before removing an EDG from service for pre-planned maintenance.

A configuration risk management program has been established at Turkey Point 3 and 4 via the implementation of the Maintenance Rule and the On line Risk Monitor to ensure the risk impact of out of service equipment is appropriately evaluated prior to performing any maintenance activity.

The Surveillance Requirements for demonstrating the OPERABILITY of the diesel generators are in accordance with the recommendations of Regulatory Guides 1.9, Selection of Diesel Generator Set Capacity for Standby Power Supplies, March 10, 1971; 1.108, Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants, Revision 1, August 1977; and 1.137, Fuel-oil Systems for Standby Diesel Generators, Revision 1, October 1979.

The EDG Surveillance testing requires that each EDG be started from normal conditions with **NO** additional warmup procedures. The surveillance frequency is controlled under the Surveillance Frequency Control Program.

Normal conditions in this instance are defined as the pre-start temperature and lube oil conditions each EDG normally experiences with the continuous use of prelube systems and immersion heaters.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

Surveillance Requirement 4.8.1.1.2.b demonstrates that each required Fuel Oil Transfer Pump operates and is capable of transferring fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This surveillance provides assurance that the Fuel Oil Transfer Pump and its control systems are capable of performing their associated support functions, and that the fuel oil piping system is intact and **NOT** obstructed. Instrument Air shall be available when performing this surveillance test. If the instrument Air System is **NOT** available, OPERABILITY of the EDG can be demonstrated by using a portable air or nitrogen source to locally open the EDG Day Tank Fill Valve. Normal Instrument Air Supply to the fill valve must be restored when the Instrument Air System is returned to service to maintain automatic operation of the system in accordance with the Diesel Fuel Oil Transfer System Design Basis.

Surveillance Requirement 4.8.1.1.2.g.7) demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal surveillances, and achieve the required voltage and frequency within 15 seconds. The 15 second time is derived from the requirements of the accident analysis to respond to a design large break Loss of Coolant Accident (LOCA). By performing this SR after 24 hours (or after two hours, in accordance with the proposed revised footnote), the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the EDG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain EDG OPERABILITY. The requirement that the diesel has operated for at least two hours at full load is based on NRC staff guidance for achieving hot conditions. Momentary transients due to changing bus loads do **NOT** invalidate this test.

Surveillance Requirement 4.8.1.1.2.g.7, verifying that the diesel generator operates for at least 24 hours, may be performed during POWER OPERATION (Mode 1) per Licensing Amendment # 221/215.

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In accordance with Technical Specification Amendments 215/209, the EDGs will be inspected in accordance with a licensee controlled maintenance program referenced in the UFSAR. The maintenance program will require inspections in accordance with procedures prepared in conjunction with the manufacturer's recommendations for this class of standby service. Changes to the maintenance program will be controlled under 10 CFR 50.59.

Diesel Fuel Oil Testing Program

The fuel supply specified for the Unit 3 EDGs is based on the original criteria and design bases used to license the plant. The specified fuel supply (Diesel Oil Storage Tank or temporary storage system) will ensure sufficient fuel for either EDG associated with Unit 3 for at least a week. The fuel supply specified for the Unit 4 EDGs is based on the criteria provided in ANSI N195-1976 as endorsed by Regulatory Guide 1.137. The specified fuel supply will ensure sufficient fuel for each EDG associated with Unit 4 for at least a week.

In accordance with TS 6.8.4, a Diesel Fuel Oil Testing Program to implement required testing of both new fuel oil and stored fuel oil shall be established. For the intent of this specification, new fuel oil shall represent diesel fuel oil that has **NOT** been added to the Diesel Fuel Oil Storage Tanks. Once the fuel oil is added to the Diesel Fuel Oil Storage Tanks, the diesel fuel oil is considered stored fuel oil, and shall meet the Technical Specification requirements for Stored Diesel Fuel Oil.

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The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has **NOT** been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the new fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tanks, but in **NO** case is the time between receipt of the new fuel oil and conducting the tests of Surveillance Requirement 4.8.1.1.2e. to exceed 30 days. The tests, limits, and applicable ASTM standards being used to evaluate the condition of new fuel oil are:

1. By obtaining a composite sample of new fuel oil in accordance with ASTM D4057 prior to addition of new fuel oil to the Diesel Fuel Oil Storage Tanks and:

2. By verifying in accordance with the tests specified in ASTM-D975-81 prior to addition to the Diesel Fuel Oil Storage Tanks that the sample has:

   a) An API Gravity of within 0.3 degrees at 60°F, or a Specific Gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate, or an Absolute Specific Gravity at 60/60°F of greater than or equal to 0.83 but less than or equal to 0.89, or an API Gravity of greater than or equal to 27 degrees but less than or equal to 39 degrees, when tested in accordance with ASTM D1298-80;

   b) A kinematic viscosity at 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes (alternatively, Saybolt viscosity, SUS at 100°F of greater than or equal to 32.6, but less than or equal to 40.1), if gravity was **NOT** determined by comparison with supplier's certification;

   c) A flash point equal to or greater than 125°F; and

   d) A clear and bright appearance with proper color when tested in accordance with ASTM-D4176-82, and ASTM-D1500-82.

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Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does **NOT** represent a failure to meet the Limiting Condition for Operation of TS 3.8.1.1, since the new fuel oil has **NOT** been added to the Diesel Fuel Oil Storage Tanks.

Within 30 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM-D975-81 are met when tested in accordance with ASTM-D975-81 except that the analysis for sulfur may be performed in accordance with ASTM˜-D1552-79 or ASTM-D2622-82. The 30 day period is acceptable because the fuel oil properties of interest, even if they are **NOT** within limits, would **NOT** have an immediate effect on EDG operation. The Diesel Fuel Oil Surveillance in accordance with the Diesel Fuel Oil Testing Program will ensure the availability of high quality diesel fuel oil for the EDGs.

Lubricity Specification for Ultra Low Sulfur Diesel Fuel Oil

To ensure that Ultra Low Sulfur Diesel fuel (15 pm sulfur, S15) is acceptable for use in the Emergency Diesel Generators, a test is added in the Diesel Fuel Oil Testing Program that validates, satisfactory lubricity (Reference: Engineering Evaluation PTN-ENG-SEMS-06-0035).

The test for lubricity is based on ASTM D975-06, testing per ASTM D6079, using the High Frequency Reciprocating Rig (HFRR) test at 60 degrees C and the acceptance criterion requires a wear scar **NO** larger than 520 microns.

At least once every 31 days, a sample of fuel oil is obtained from the storage tanks in accordance with ASTM-D2276-78. The particulate contamination is verified to be less than 10 mg/liter when checked in accordance with ASTM-D2276-78, Method A. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

Fuel oil degradation during long term storage shows up as 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 can cause engine failure.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

The frequency for performing surveillance on stored fuel oil is based on stored fuel oil degradation trends which indicate that particulate concentration is unlikely to change significantly between surveillances.

The OPERABILITY of the minimum specified A.C. and D.C. Power Sources and associated distribution systems during shutdown and refueling ensures that (1) The facility can be maintained in the shutdown or refueling condition for extended time periods, and (2) Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

During a unit shutdown, the one required circuit between the offsite transmission network and the onsite Class 1E Distribution System can consist of at least the associated unit startup transformer feeding one 4160 volt Bus A or B, or the opposite unit's startup transformer feeding the associated unit's 4160 volt Bus A, or the associated unit's 4160 volt Bus A or B backfed through its auxiliary transformers with the main generator isolated.

As inoperability of numerous electrical components often affects the operation of the opposite unit, the applicability for the shutdown LIMITING CONDITION FOR OPERATION (LCO) for A.C. Sources, D.C. Sources and Onsite Power Distribution all contain statements to ensure the LCOs of the opposite unit are considered.

The allowable out-of-service time for the D.C. busses is 24 hours with one unit shutdown in order to allow for required battery maintenance without requiring both units to be shutdown. Provisions to substitute the spare battery for any one of the four station batteries have been included to allow for battery maintenance without requiring both units to be shutdown. The requirement to have only one OPERABLE battery charger associated with a required battery bank permits maintenance to be conducted on the redundant battery charger.

A battery charger may be considered acceptable when supplying less than 10 amperes provided:

1) The battery charger's ability to independently accept and supply the D.C. bus has been verified within the previous 7 days and,

2) D.C. output voltage is ≥ 129 volts.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

The minimum number of battery chargers required to be OPERABLE is based on the following criteria:

1) A minimum of one battery charger per bus with each powered from a separate 480 volt MCC is required to satisfy the single failure criteria when assuming the failure of a MCC. This restriction prohibits the use of two chargers powered from the same bus for meeting the minimum requirements.

2) To satisfy the single failure criteria, when assuming a Loss-Of-Offsite Power with the loss of an EDG, an additional restriction is stipulated which requires each battery charger to have its associated diesel generators OPERABLE. This requires both EDGs associated with a swing bus battery charger to be OPERABLE.

Provisions for requiring the OPERABILITY of the EDG associated with the battery charger is explicitly specified in the LCO. This is because conditions exist where the affected unit would **NOT** enter the applicable ACTION statement in the LCO without this provision. For example, with Unit 3 in MODE 1 and Unit 4 in MODE 5, the operability of both EDG 4A and 4B is **NOT** required. One could postulate conditions where battery chargers 4A1, 3A2, 3B2, or 4B1 could be used to satisfy the LCO without having an associated OPERABLE EDG, unless specific provisions were made to preclude these conditions.

An out-of-service limit of 72 hours is applied when the required EDG is **NOT** OPERABLE. With less than the required battery chargers OPERABLE, an allowable out-of-service time of 2 hours is applied, which can be extended to 24 hours if the opposite unit is in MODES 5 or 6 and each of the remaining required battery chargers is capable of being powered from its associated diesel generators.

Verifying average electrolyte temperature above the minimum for which the battery was sized, total battery terminal voltage on float charge, connection resistance values, and the performance of battery service and discharge tests ensure the effectiveness of the charging system, the ability to handle high discharge rates, and verifies the battery capability to supply its required load.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

Table 4.8-2 specifies the normal limits for each designated pilot cell and each connected cell for electrolyte level, float voltage, and specific gravity. The limits for the designated pilot cell's float voltage and specific gravity, greater than 2.13 volts and **NOT** more than 0.015 below the manufacturer's full charge specific gravity or a battery charger current that had stabilized at a low value, is characteristic of a charged cell with adequate capacity. The normal limits for each connected cell for float voltage and specific gravity, greater than 2.13 volts and **NOT** more than 0.020 below the manufacturer's full charge specific gravity with an average specific gravity of all connected cells **NOT** more than 0.010 below the manufacturer's full charge specific gravity, ensures the OPERABILITY and capability of the battery.

Operation with a battery cell's parameter outside the normal limit but within the allowable value specified in Table 4.8-2 is permitted for up to 7 days. During this period: (1) The allowable values for electrolyte level ensures **NO** physical damage to the plates with an adequate electron transfer capability; (2) The allowable value for the average specific gravity of all the cells, **NOT** more than 0.020 below the manufacturer's recommended full charge specific gravity, ensures that the decrease in rating will be less than the safety margin provided in sizing;
(3) The allowable value for an individual cell's specific gravity ensures that an individual cell's specific gravity will **NOT** be more than 0.040 below the manufacturer's full charge specific gravity and that the overall capability of the battery will be maintained within an acceptable limit; and (4) The allowable value for an individual cell's float voltage, greater than or equal to 2.07 volts, ensures the battery's capability to perform its design function.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

The ACTION requirements specified for the inoperability of certain Motor Control Centers (MCCs), Load Centers (LCs) and the 4160-Volt Busses provide restrictions upon continued facility operation commensurate with the level of degradation on each unit and the amount of time one could reasonably diagnose and correct a minor problem. The level of degradation is based upon the types of equipment powered and the out-of-service limit imposed on that equipment by the associated ACTION statement. If this degradation affects the associated unit only, then **NO** restriction is placed on the opposite unit and an out-of-service limit of 8 hours (except for MCCs 3A, 3K, 4J and 4K) is applied to the associated unit. Since MCCs 3A, 3K, 4J and 4K are used to power EDG auxiliaries, an out-of-service limit of 72 hours is applied as required by 3.8.1.1. If the degradation impacts both units (i.e., required shared systems or cross-unit loads), then an out-of-service limit of 8 hours is applied to the associated unit and an out-of-service limit based on the most restrictive ACTION requirement for the applicable shared or cross-unit load is applied to the opposite unit.

For example, if being used to satisfy 3.8.2.1, the Battery Chargers 3A2, 3B2, 4A2, and 4B2 are cross-unit loads and have out-of-service limits of 2 hours. This is the most restrictive limit of the applicable equipment powered from MCC 3D and 4D. Therefore, an out of service limit of 2 hours is applied if the battery charger is required to be OPERABLE.

The ACTION requirements specified when an A.C. vital panel is **NOT** energized from an inverter connected to its associated D.C. bus provides for two phases of restoration. Expedient restoration of an A.C. panel is required due to the degradation of the Reactor Protection System and vital instrumentation. The first phase requires re-energization of the A.C. vital panel within two hours. During this phase the panel may be powered by a Class 1E constant voltage transformer (CVT) fed from a vital MCC. However, the condition is permissible for only 24 hours as the second phase of the ACTION requires re-energization of the A.C. vital panel from an inverter connected to its associated D.C. bus within 24 hours. Failure to satisfy these ACTIONS results in a dual unit shutdown.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

Chapter 8 of the UFSAR provides the description of the A.C. electrical distribution system. The 480 Volt Load Center busses are arranged in an identical manner for Units 3 and 4. For each unit there are five safety related 480v load center busses, four of which are energized from different 4.16 kV busses (Load Centers A and C are fed from Train A and Load Centers B and D are fed from Train B). This arrangement ensures the availability of equipment associated with a particular function in the event of loss of one 4.16 kV bus.

The fifth safety related 480V load center in each unit is a swing load center, which can swing between Load Center C and D of its associated unit. These load centers are labeled as 3H for Unit 3 and 4H for Unit 4. When the 480V swing load center is connected to either 480V supply bus, it is considered to be an extension of that 480V supply bus.

Technical Specification (TS) 3/4.8.3.1 contains a *** footnote that states: “Electrical bus can be energized from either train of its unit and swing function to opposite train must be OPERABLE for the Unit(s) in MODES 1, 2, 3, and 4.” The *** footnote establishes that TS Limiting Conditions for Operation (LCO) 3.8.3.1a, b, and c are met by the electrical bus train energizing the swing Load Center (LC) H and Motor Control Center (MCC) D. Therefore, any loss of power to swing LC H or MCC D, or the loss of swing capability only affects the fully energized requirement for the associated bus train and not the opposite bus train because the opposite bus train was not being relied on to meet the LCO. Action ‘a’ or ‘b’ is entered depending on whether the electrical bus train is for the associated unit or opposite unit, respectively.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

The swing load centers are used to supply shared system and cross-unit loads, and other Technical Specification ACTION statements may be invoked for loss of swing capability. As discussed above, the Unit 3 DC battery chargers 3A2 and 3B2 are powered from Unit 4 via swing MCC 4D, and the Unit 4 DC battery chargers 4A2 and 4B2 are powered from Unit 3 via swing MCC 3D. Inoperability of the swing capability could impact both units if any of the swing battery chargers is credited for satisfying Technical Specification 3.8.2.1. Both EDGs are required to be OPERABLE for a swing battery charger. An inoperable swing function prevents one EDG from supporting that battery charger, and a dual-unit 72 hour ACTION statement applies in accordance with TS 3.8.2.1 ACTION statement a.

With a unit shutdown one 4160-volt bus on the associated unit can be deenergized for periodic refueling outage maintenance. The associated 480-volt Load Centers can then be cross-tied upon issuance of an engineering evaluation.

For the shutdown unit, the swing load center does **NOT** have to be powered from a diesel backed source, since:

a) Technical Specification 3.8.3.2 only requires that the swing load center be energized. **NO** operability requirements are specified for the swing function (as opposed to the requirements for an operating unit) and

b) The only accident postulated to occur in Modes 5 and 6 is a fuel handling accident. Loss of offsite power is **NOT** assumed to occur concurrently with these events. Additionally, there is **NO** causal relationship between a fuel handling event and a loss of offsite power. Thus, from a design basis standpoint, all of the Control Room HVAC safety functions can be accomplished with the swing load center energized from an offsite source.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

Operating units on the other hand are subject to accidents that can both affect the grid, and release radioactivity to the outside environment, e.g., LOCA, MSLB. Thus, to satisfy the design basis requirements for the Control Room HVAC system when a unit is in MODES 1 - 4, the swing load center must be powered from a diesel-backed source.

For an operating unit, the swing load center also has to be powered from a diesel-backed source to be considered OPERABLE. The swing load center is considered to be powered from a diesel-backed source if:

a) It is connected to an electrical power train that has an OPERABLE diesel generator, or

b) It can automatically transfer to a bus that has an OPERABLE diesel generator.

If Load Center H is energized from a load center (either C or D) that does **NOT** have an OPERABLE Emergency Diesel Generator aligned to it and the swing function is also inoperable, then a 2-hour or a 72 hour LCO would have to be entered, depending on the battery charger requirements (Technical specification Tables 3.8-1 and 3.8-2).

The swing load center will momentarily de-energize any time it transfers between supply busses (manual, automatic, or test conditions). Since this is the specified manner of operation, the momentary load center de-energization does **NOT** require entry into the Technical Specification 3/4.8.3.2 action statement.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

Although Load Center H is de-energized for a short period of time (~1.5 seconds), it is considered to be energized in the specified manner. The design of the transfer scheme inherently relies on break before make contacts to swing between the two redundancy supply busses. The design allows for a total of 2.5 seconds to accomplish the automatic transfer – 1.5 seconds to trip the supply breaker of the aligned train and an additional 1.0 second delay (i.e., dead time) to close the opposite train supply breaker. This prevents the A and B trains from being interconnected during the transfer function. The basic concept of the transfer is that the transfer only occurs on a dead bus. This is accomplished by tripping and verifying that the bus is dead prior to closing the supply breaker to the alternate power supply.

Vital sections of the MCCs shown in the following table must be energized to satisfy Technical Specification Action 3.8.3.2.a:

Train in Service	3A	3B	4A	4B	Reason
MCCs	3A	3B	4A	4B	Major Safety MCCs
	3C		4C		Major Safety MCCs
	3D	3D	4D	4D	CR HVAC
		3K	4J	4K	EDG Auxiliaries

MCCs 3K, 4J, and 4K were added during the EPS Upgrade Project. Auxiliaries for the 3A EDG were left on the 3A MCC. As a result, only Unit 4 Train A needs four MCC vital sections energized, as shown on the Table above.

The **NO** Significant Hazards Determination for the EPS Upgrade Technical Specifications stated, The description of the 480 volt emergency bus requirements has been modified to reflect additional LCs and MCCs added by the EPS Enhancement Project. Due to the addition of new LCs 3H/4H, MCCs 3K/4K, MCC 4D and MCC 4J, the LCO now requires the availability of three 480 volt LCs and three MCC bus vital sections (four MCC bus vital sections for Unit 4).

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3/4.9 Refueling Operations

3/4.9.1 Boron Concentration

The limitations on reactivity conditions during REFUELING ensure that: (1) The reactor will remain subcritical during CORE ALTERATIONS, and (2) A uniform boron concentration is maintained for reactivity control in the water volume having direct access to the reactor vessel. These limitations are consistent with the initial conditions assumed for the boron dilution incident in the safety analyses. With the required valves CLOSED during refueling operations, the possibility of uncontrolled boron dilution of the filled portion of the RCS is precluded. This action prevents flow to the RCS of unborated water by closing flow paths from sources of unborated water. The boration rate requirement of 16 gpm of 3.0 wt% (5245 ppm) boron or equivalent ensures the capability to restore the SHUTDOWN MARGIN with one OPERABLE charging pump.

3/4.9.2 Instrumentation

The OPERABILITY of the Source Range Neutron Flux Monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core. There are four source range neutron flux channels, two primary, and two backup. All four channels have visual and alarm indication in the Control Room and interface with the Containment Evacuation Alarm System. The primary source range neutron flux channels can also generate reactor trip signals and provide audible indication of the count rate in the Control Room and containment. At least one primary source range neutron flux channel to provide the required audible indication, in addition to its other functions, and one of the three remaining source range channels shall be OPERABLE to satisfy the LCO.

T.S. surveillance requirement 4.9.2.b and c states:

Each required Source Range Neutron Flux Monitor shall be demonstrated OPERABLE by performance of:

b. An ANALOG CHANNEL OPERATIONAL TEST within 8 hours prior to the initial start of CORE ALTERATIONS, and

c. An ANALOG CHANNEL OPERATIONAL TEST in accordance with the Surveillance Frequency Control Program.

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3/4.9.2 (Continued)

A normal refueling consists of 2 CORE ALTERATION sequences: unloading the core, and reloading the core, typically with a suspension of CORE ALTERATIONS in between. The core unload sequence begins with control rod unlatching, followed by removal of upper internals, followed by unloading fuel assemblies to the SFP. The core reload sequence consists of reloading fuel assemblies from the SFP, followed by upper internals installation, followed by latching control rods. Therefore, if T.S. 4.9.2.c is complied with following the ANALOG CHANNEL OPERATIONAL TEST performed within 8 hours prior to start of control rod unlatching, then the ANALOG CHANNEL OPERATIONAL TEST need **NOT** be performed within 8 hours prior to the start of core reload. Otherwise, comply with T.S.4.9.2.b within 8 hours prior to the start of core reload.

3/4.9.3 Decay Time

The minimum requirement for reactor subcriticality prior to movement of irradiated fuel assemblies in the reactor vessel ensures that sufficient time has elapsed to allow the radioactive decay of short-lived fission products. This decay time is consistent with the assumptions used in the safety analyses, and ensures that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within the values specified in 10 CFR 50.67 and RG 1.183.

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3/4.9.3 (Continued)

This TS is applicable during movement of recently irradiated fuel assemblies within containment. Recently irradiated fuel is defined as fuel that has occupied part of a critical reactor core within the previous 72 hours. However, the administrative controls as well as the inherent delay associated with completing the required preparatory steps for moving fuel in the reactor vessel will ensure that the proposed 72-hour decay time will be met prior to removing irradiated fuel from the reactor vessel for a refueling outage. The FHA is a postulated event that involves damage to irradiated fuel. The in-containment FHA involves dropping a single irradiated fuel assembly, resulting in damage to a single fuel assembly. The 72-hour required decay time before moving fuel in containment ensures that sufficient time has elapsed to allow the radioactive decay of short-lived fission products. This decay time is consistent with the assumptions used in the Safety Analyses, and ensures that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within the values specified in 10 CFR 50.67 and RG 1.183.

3/4.9.4 Containment Building Penetrations

FPL revised the design basis for the Turkey Point Units 3 and 4 FHA analysis using the Alternate Source Term (AST) methodology. This is a selective implementation of the AST methodology, and the calculations were done in accordance with Reg. Guide (RG) 1.183, Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors.

The containment airlocks, which are part of the containment pressure boundary, provide a means for personnel access during MODES 1, 2, 3, and 4 operation. During periods of 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, both doors of the containment personnel airlock may be open provided (a) At least one personnel airlock door is capable of being closed, (b) The plant is in MODE 6 with at least 23 feet of water above the fuel, and (c) A designated individual is available outside the personnel airlock to close the door.

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3/4.9.4 (Continued)

The Containment Equipment Door, 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 the Containment Equipment Door can be open. FPL has committed to implement the guidelines of NUMARC 93-01, Rev. 3, Section 11.3.6.5, which require (1) Assessment of the availability of Containment Ventilation and Containment Radiation Monitoring [satisfied by compliance with TS 3.9.9 and 3.9.13, respectively], and (2) Development of a prompt method of closure of Containment Penetrations. Administrative controls have been developed to satisfy this commitment (ref: L-2001-201).

Containment closure ensures 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 presence of a designated individual available outside of the personnel airlock to close the door, and a designated crew available to close the equipment door will minimize the release of radioactive materials.

Administrative requirements are established for the responsibilities and appropriate actions of the designated individuals in the event of a FHA inside containment. These requirements include the responsibility to be able to communicate with the Control Room, to ensure that the equipment door is capable of being closed, and to close the equipment door in the event of a fuel handling accident. These administrative controls ensure containment closure will be established in the event of a fuel handling accident inside containment. In accordance with Regulatory Guide 1 .183, these administrative controls assure that the personnel airlock and equipment door will be closed within 30 minutes.

3/4.9.5 Deleted

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3/4.9.6 Deleted

3/4.9.7 Deleted

3/4.9.8 Residual Heat Removal and Coolant Circulation

The requirement that at least one residual heat removal (RHR) loop be in operation ensures that: (1) Sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor vessel below 140°F as required during the REFUELING MODE, and (2) Sufficient coolant circulation is maintained through the core to minimize the effect of a boron dilution incident and prevent boron stratification.

The requirement to have two RHR loops OPERABLE when there is less than 23 feet of water above the reactor vessel flange ensures that a single failure of the operating RHR loop will **NOT** result in a complete loss of residual heat removal capability. With the reactor vessel head removed and at least 23 feet of water above the reactor pressure vessel flange, a large heat sink is available for core cooling. Thus, in the event of a failure of the operating RHR loop, adequate time is provided to initiate emergency procedures to cool the core.

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR loops and may also prevent water hammer, pump cavitation, and pumping of non-condensable gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrument drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

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3/4.9.8 (Continued)

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The 31 day frequency for ensuring locations are sufficiently filled with water takes into consideration the gradual nature of gas accumulation in the RHR System piping and the procedural controls governing system operation.

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3/4.9.9 Containment Ventilation Isolation System

The OPERABILITY of this system ensures that the containment ventilation penetrations will be automatically isolated upon detection of high radiation levels within the containment. The OPERABILITY of this system is required to restrict the release of radioactive material from the containment atmosphere to the environment.

T.S. surveillance requirement 4.9.9 states:

4.9.9 The Containment Ventilation Isolation System shall be demonstrated OPERABLE within 100 hours prior to the start of and in accordance with the Surveillance Frequency Control Program during CORE ALTERATIONS by verifying that Containment Ventilation Isolation occurs on a High Radiation test signal from each of the containment radiation monitoring instrumentation channels.

A normal refueling consists of 2 CORE ALTERATION sequences: unloading the core, and reloading the core, typically with a suspension of CORE ALTERATIONS in between. The core unload sequence begins with control rod unlatching, followed by removal of upper internals, followed by unloading fuel assemblies to the SFP. The core reload sequence consists of reloading fuel assemblies from the SFP, followed by upper internals installation, followed by latching control rods. Therefore, if the Containment Ventilation Isolation System is demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program following the specified testing within 100 hours prior to the start of control rod unlatching, then Containment Ventilation Isolation System operability need **NOT** be demonstrated within 100 hours prior to the start of core reload. Otherwise, the specified testing is required to be performed within 100 hours prior to the start of core reload.

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3/4.9.10
&
3/4.9.11 Water Level – Reactor Vessel and Storage Pool

The restrictions on minimum water level ensure that sufficient shielding will be available during fuel movement and for removal of iodine in the event of a fuel handling accident. The minimum water depth is consistent with the assumptions of the safety analysis.

3/4.9.12 Deleted

3/4.9.13 Radiation Monitoring

The OPERABILITY of the containment radiation monitors ensures continuous monitoring of radiation levels to provide immediate indication of an unsafe condition.

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3/4.9.14 Spent Fuel Storage

The Spent Fuel Storage racks provide safe subcritical storage of fuel assemblies by providing sufficient center-to-center spacing or a combination of spacing and poison to assure: a) Keff less than or equal to 0.95 with a minimum soluble boron concentration of 500 ppm present, and b) Keff less than 1.0 when flooded with unborated water for normal operations and postulated accidents. The 500 ppm value is needed to assure keff less than 0.95 for normal operating conditions. The criticality analysis needs 1700 ppm to assure keff less than 0.95 under the worst case accident condition. There is significant margin between the calculated ppm requirement and the spent fuel boron concentration requirement of 2300 ppm. The higher boron concentration value is chosen because, during refueling, the water volume in the spent fuel pool, the transfer canal, the refueling canal, the refueling cavity, and the reactor vessel form a single mass.

The spent fuel racks are divided into two regions, Region I and Region II. The Region I permanent racks have a 10.6 inch center-to-center spacing. The Region II racks have a 9.0 inch center-to-center spacing. The cask area storage rack has a nominal 10.1 inch center to center spacing in the east-west direction and a nominal 10.7 inch center-to-center spacing in the north-south direction.

Any fuel for use at Turkey Point, and enriched to less than or equal to 5.0 wt % U-235, may be stored in the Cask Area Storage Rack. Fresh or irradiated fuel assemblies **NOT** stored in the Cask Area Storage Rack shall be stored in accordance with Specification 5.5.1.3.

Fresh unirradiated fuel may be placed in the permanent Region I racks in accordance with the restrictions of Figure 5.5-1. Prior to placement of irradiated fuel in Region I or II spent fuel storage rack cell locations, strict controls are employed to evaluate burnup of the fuel assembly. Upon determination that the fuel assembly meets the nominal burnup and associated post-irradiation cooling time requirements of Table 5.5-1 or Table 5.5-2, it may be placed in a Region I or II cell in accordance with the restrictions of Figures 5.5-1 or 5.5-2, respectively.

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3/4.9.14 (Continued)

For all assemblies with blanketed fuel, the initial enrichment is based on the central zone enrichment (i.e., between the axial blankets) consistent with the assumptions of the analysis. These positive controls assure that the fuel enrichment limits, burnup, and post-irradiation cooling time requirements assumed in the safety analyses will **NOT** be violated.

3/4.10 Special Test Exceptions

3/4.10.1 Shutdown Margin

This special test exception provides that a minimum amount of control rod worth is immediately available for reactivity control when tests are performed for control rod worth measurement. This special test exception is required to permit the periodic verification of the actual versus predicted core reactivity condition occurring as a result of fuel burnup or fuel cycling operations.

3/4.10.2 Group Height, Insertion, and Power Distribution Limits

This special test exception permits individual control rods to be positioned outside of their normal group heights and insertion limits during the performance of such PHYSICS TESTS as those required to measure control rod worth.

3/4.10.3 Physics Tests

This special test exception permits PHYSICS TESTS to be performed at less than or equal to 5% of RATED THERMAL POWER with the RCS Tavg slightly lower than normally allowed so that the fundamental nuclear characteristics of the core and related instrumentation can be verified. In order for various characteristics to be accurately measured, it is at times necessary to operate outside the normal restrictions of these Technical Specifications. For instance, to measure the Moderator Temperature Coefficient at BOL, it is necessary to position the various control rods at heights which may **NOT** normally be allowed by Specification 3.1.3.6 which in turn may cause the RCS Tavg to fall slightly below the minimum temperature of Specification 3.1.1.4.

3/4.10.4 (This specification number is **NOT** used.)

ATTACHMENT 2
Technical Specification Bases
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3/4.10.5 Position Indication System - Shutdown

This special test exception permits the Position Indication Systems to be inoperable during rod drop time measurements. The exception is required since the data necessary to determine the rod drop time are derived from the induced voltage in the position indicator coils as the rod is dropped. This induced voltage is small compared to the normal voltage and, therefore, cannot be observed if the Position Indication Systems remain OPERABLE.