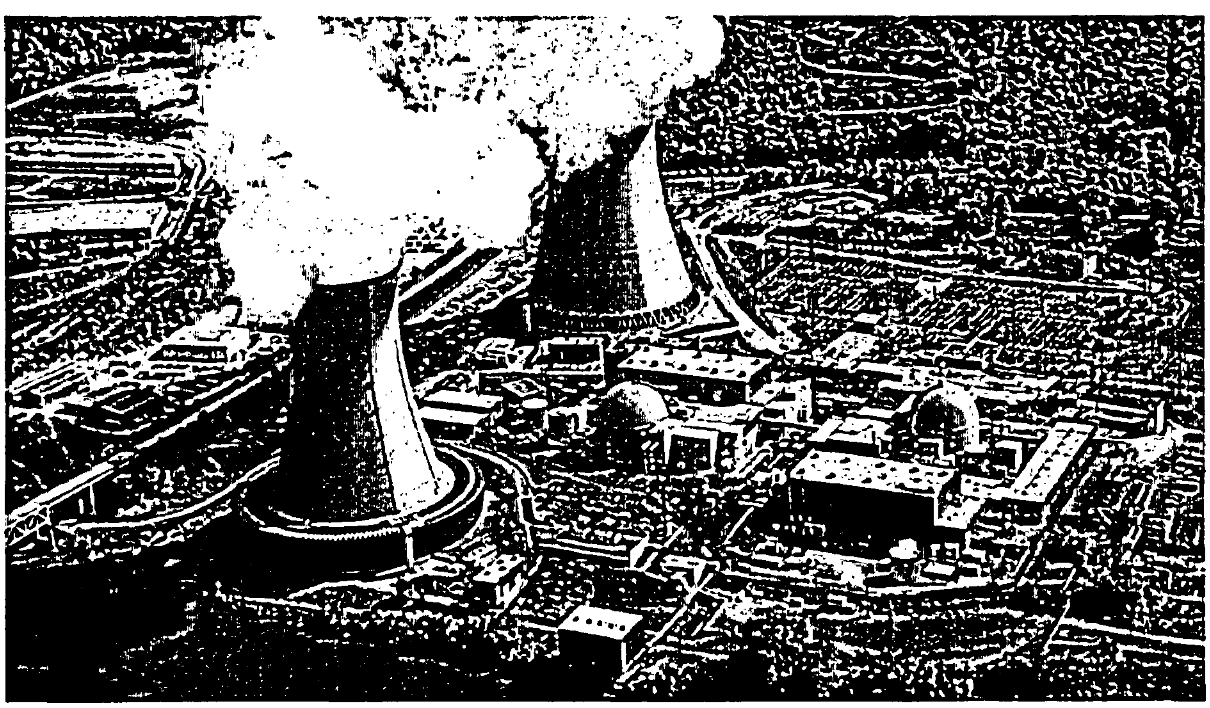
Beaver Valley Power Station Unit Nos. 1 and 2

License Amendment Requests 302 and 173

Extended Power Uprate

FENOC Letter

L-04-125



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October 4, 2004
L-04-125

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Subject: Beaver Valley Power Station, Unit No. 1 and No. 2
BV-1 Docket No. 50-334, License No. DPR-66
BV-2 Docket No. 50-412, License No. NPF-73
License Amendment Request Nos. 302 and 173

Pursuant to 10 CFR 50.90, FirstEnergy Nuclear Operating Company (FENOC) requests an amendment to the above licenses in the form of changes to the Beaver Valley Power Station (BVPS) Operating Licenses and Technical Specifications. This License Amendment Request (LAR) proposes Operating License and Technical Specification (TS) changes which support an approximate 8% increase in the licensed power level from the current level of 2689 MWt to 2900 MWt Rated Thermal Power (RTP). This Extended Power Uprate (EPU) LAR also proposes changes reflecting the installation of replacement steam generators in BVPS Unit No. 1. Approval of this EPU LAR is being requested to support the installation of the BVPS Unit No. 1 replacement steam generators in the 2006 spring outage. The EPU analyses are also based, in part, on the use of the NRC approved Westinghouse Best Estimate Loss-of-Coolant Accident (BELOCA) methodology (WCAP-12945-P-A) for a large break LOCA. FENOC is submitting a separate LAR (318/191) to request approval of the BELOCA methodology for BVPS.

Both the EPU and BELOCA LARs are based on the analyses performed for the conversion of the BVPS containment buildings to an atmospheric design. By letter L-04-73 dated June 2, 2004, FENOC submitted the containment conversion LAR (317/190) for BVPS. The containment conversion LAR proposes TS changes that will permit each unit to be operated with an atmospheric containment design. The requested approval of the containment conversion LAR is June 2005 with amendment implementation to occur during each unit's 2006 refueling outage.

The principal changes proposed in this EPU LAR include:

- an Extended Power Uprate (EPU) which will raise the licensed power level from 2689 megawatts thermal (MWt) to 2900 MWt for each unit;

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- changes that will permit operation of Unit No. 1 with the replacement steam generators (Model 54F) installed;
- deletion of the Power Range, Neutron Flux High Negative Rate trip for both units; and
- full implementation of the Alternative Source Terms (AST) methodology in accordance with Regulatory Guide 1.183 "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors."

This EPU LAR contains six enclosures and seven attachments. The proposed Technical Specification changes are provided in Attachments A-1 and A-2 for Unit Nos. 1 and 2, respectively. The proposed changes to the Technical Specification Bases are provided in Attachments B-1 and B-2 for Unit Nos. 1 and 2, respectively. The proposed changes to the Licensing Requirements Manual (LRM) are provided in Attachments C-1 and C-2 for Unit Nos. 1 and 2, respectively. The Technical Specification Bases and LRM changes are provided for information only. The regulatory commitments associated with this request are provided in Attachment D.

Enclosure 1 contains the FENOC evaluation of the proposed changes. This enclosure contains a description of the proposed changes, a technical analysis supporting the proposed changes, a no significant hazards consideration and an environmental consideration.

Enclosure 2 contains the Extended Power Uprate Licensing Report that describes the revised safety and radiological analyses conducted to support the EPU changes.

Enclosure 3 contains markups of the matrices of Section 2.1 of the NRC Review Standard for Extended Power Uprates - RS-001, Revision 0. This is provided to aid the staff's review of the BVPS EPU submittal.

Enclosure 4 contains WCAP-16307-P (Proprietary Version) and WCAP-16307-NP (Non-proprietary Version), "Beaver Valley Units 1 and 2 Extended Power Uprate Licensing Report Supplemental Information," September 2004.

Enclosure 5 contains WCAP-13483-P, Revision 2, (Proprietary Version) and WCAP-13484-NP, Revision 2 (Non-proprietary Version), "Beaver Valley Units 1 and 2 Westinghouse Series 51 Steam Generator Sleeving Report - Laser Welded Sleeves," Revision 2, October 2002.

Enclosure 6 contains affidavits CAW-04-1897 and CAW-04-1898. As WCAP-16307-P and WCAP-13483-P, Revision 2 (provided in Enclosures 4 and 5) contain information proprietary to Westinghouse, each is supported by an affidavit signed by Westinghouse, the owner of the information. Accordingly, Enclosure 6 includes Westinghouse Applications for Withholding Proprietary Information from Public Disclosure. The affidavits set forth the basis on which the requested information may be withheld from public disclosure by the Commission, and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR 2.390 of the Commission's regulations. Accordingly, FENOC requests that the information, which is proprietary to Westinghouse, be withheld from public disclosure in accordance with 10 CFR 2.390.

Correspondence regarding the proprietary aspects of WCAP-16307-P and WCAP-13483-P, Revision 2, or the supporting affidavits, should reference Westinghouse letters FENOC-04-172 and FENOC-04-173 and be addressed to J. A. Gresham, Manager Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P. O. Box 355, Pittsburgh, PA 15230-0355, Phone: 412-374-4643.

The safety and radiological analyses conducted to support the EPU changes have been completed for each unit assuming an atmospheric containment design and adoption of the Westinghouse Best-Estimate Loss-of-Coolant Accident (BELOCA) analysis methodology. Therefore, implementation of the requested EPU amendments is contingent upon implementation of the requested containment conversion and BELOCA amendments.

FENOC requests approval of the proposed EPU amendments by November 2005 in order to support the installation of the BVPS Unit No. 1 replacement steam generators during the 2006 spring outage. However, since a number of the Technical Specification changes proposed in this EPU LAR require a plant outage to implement, FENOC requests the following implementation periods. The Unit No. 1 EPU amendment shall be implemented prior to the first entry into Mode 4 during plant startup from the 1R17 refueling outage planned for the spring of 2006. The Unit No. 2 EPU amendment shall be implemented prior to the first entry into Mode 4 during plant startup from the 2R12 refueling outage planned for the fall of 2006.

The proposed changes have been reviewed by the Beaver Valley Power Station review committees. The changes were determined to be safe and do not involve a significant hazard consideration as defined in 10 CFR 50.92 based on the attached safety analysis and no significant hazard evaluation.

If there are any questions concerning this matter, please contact Mr. Henry L Hegrat, Supervisor, Licensing at 330-315-6944.

I declare under penalty of perjury that the foregoing is true and correct. Executed on October 4, 2004.

Sincerely,

L. W. Pearce

L. William Pearce

Enclosures:

1. FENOC Evaluation of the Proposed Changes.
2. Extended Power Uprate Licensing Report.
3. Markups of NRC Review Standard for Extended Power Uprates – RS-001, Revision 0, Section 2.1 matrices.
4. WCAP-16307-P (Proprietary Version) and WCAP-16307-NP (Non-proprietary Version), "Beaver Valley Units 1 and 2 Extended Power Uprate Licensing Report Supplemental Information," September 2004.
5. WCAP-13483-P, Revision 2, (Proprietary Version) and WCAP-13484-NP, Revision 2 (Non-proprietary Version), "Beaver Valley Units 1 and 2 Westinghouse Series 51 Steam Generator Sleeving Report - Laser Welded Sleeves," Revision 2, October 2002.
6. Affidavits CAW-04-1897 and CAW-04-1898.

Attachments:

A-1 Proposed Unit No. 1 Technical Specification Changes
A-2 Proposed Unit No. 2 Technical Specification Changes
B-1 Proposed Unit No. 1 Technical Specification Bases Changes
B-2 Proposed Unit No. 2 Technical Specification Bases Changes
C-1 Proposed Unit No. 1 Licensing Requirements Manual Changes
C-2 Proposed Unit No. 2 Licensing Requirements Manual Changes
D List of Commitments

c: Mr. T. G. Colburn, NRR Senior Project Manager
Mr. P. C. Cataldo, NRC Sr. Resident Inspector
Mr. S. J. Collins, NRC Region I Administrator
Mr. D. A. Allard, Director BRP/DEP
Mr. L. E. Ryan (BRP/DEP)

ENCLOSURE 1

FENOC Evaluation of the Proposed Changes

Beaver Valley Power Station
License Amendment Requests
302 (Unit 1) and 173 (Unit 2)

Subject: Application for an Extended Power Uprate for Beaver Valley Power Station Unit Nos. 1 and 2.

Table of Contents

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Attachments

Number	Title
A-1	Proposed Unit 1 Technical Specification Changes
A-2	Proposed Unit 2 Technical Specification Changes
B-1	Proposed Unit 1 Technical Specification Bases Changes
B-2	Proposed Unit 2 Technical Specification Bases Changes
C-1	Proposed Unit 1 Licensing Requirements Manual Changes
C-2	Proposed Unit 2 Licensing Requirements Manual Changes
D	Commitment Summary

1.0 DESCRIPTION

This is a request to amend Operating Licenses DPR-66 (Beaver Valley Power Station Unit No. 1) and NPF-73 (Beaver Valley Power Station Unit No. 2) to permit an Extended Power Uprate (EPU) to 2900 megawatts thermal (MWt). Throughout this License Amendment Request (LAR) all cited power levels are in Rated Thermal Power (RTP), unless otherwise noted.

The proposed changes will revise the Beaver Valley Power Station (BVPS) Unit 1 Operating License to permit operating at 2900 MWt with replacement steam generators (Model 54F) installed. The proposed changes will revise the BVPS Unit 2 Operating License to permit operating at 2900 MWt using the original steam generators (Model 51M).

The proposed changes reflect revised safety and radiological analysis, as documented in Enclosure 2, Beaver Valley Power Station Extended Power Uprate Licensing Report.

Approval of this LAR will change the BVPS licensing and design basis to include power operation at 2900 MWt. However, the actual uprate to the EPU power level of 2900 MWt may occur in stages. The staged approach is due to the fact that certain balance of plant (BOP) modifications may not be completed by the requested amendment implementation date. With the approval of the EPU analyses, the BVPS units will be approved to operate at 2900 MWt. However, although all safety related modifications will be completed prior to amendment implementation, without certain BOP modifications the megawatts electric (MWe) output will be limited to the existing value. Since the supporting EPU analyses bound operation at the pre-EPU level of 2689 MWt, it is acceptable to continue operation at the pre-EPU level until the necessary BOP modifications have been completed. Reactor power may be raised in stages as the necessary BOP modifications are completed. Following NRC approval of plant operations at 2900 MWt, the actual value of Rated Thermal Power (RTP) will be controlled by the proposed changes to the Technical Specifications, the Licensing Requirements Manual and the BVPS 10 CFR 50.59 process.

This LAR includes changes that are required to support the EPU and others that are not directly related to the EPU, but are being made to enhance the existing BVPS Technical Specifications, including ones that are considered as administrative.

The EPU related Technical Specification (TS) changes requested include:

(a) increasing the Maximum Power Level specified in each unit's license;

(b) revising the value and definition of Rated Thermal Power (RTP);

(c) revising fuel assembly specific departure from nucleate boiling ratios and correlations;

(d) raising the maximum temperature of the refueling water storage tank;

(e) modifying Overtemperature ΔT and Overpower ΔT equations for BVPS Unit 1 only;

(f) revising the steam generator water level low-low and high-high setpoints for BVPS Unit 1 only;

(g) revising the required steam generator secondary side level in Modes 4 and 5 for BVPS Unit 1 only;

(h) raising the tolerance settings for the pressurizer safety valves;

(i) revising the steam generator Technical Specification to reflect the replacement steam generators for BVPS Unit 1 only;

(j) revising steam generator Technical Specification tube sleeve reference and the TIG welded steam generator sleeve repair limit for BVPS Unit 2 only;

(k) revising the specific activity of the primary coolant system for BVPS Unit 1 only;

(l) increasing the band for accumulator water volume and nitrogen pressure;

(m) revising the required charging pump discharge pressure for reactor coolant pump seal injection flow;

(n) revising the tolerance settings for the main steam safety valves;

(o) changing the allowable power limits associated with inoperable main steam safety valves;

(p) revising the primary plant demineralized water storage tank volume;

(q) revising the specific activity of the secondary coolant system for BVPS Unit 1 only; and

(r) adding WCAP-14565 and WCAP-15025 to the list of NRC approved methodologies in Technical Specification 6.9.5.

A change to the BVPS licensing basis that is not directly reflected in the Technical Specifications, but is consistent with EPU analysis and requires NRC approval, is full implementation of the Alternative Source Term methodology of Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors" (Reference 1).

The Technical Specification changes requested that are not directly related to the EPU include:

(a) deletion of the Power Range, Neutron Flux High Negative Rate trip;

(b) addition of a footnote to Table 3.3-3, Engineered Safety Features Actuation System Instrumentation, concerning time constants for steamline pressure low for BVPS Unit 1 only;

(c) removal of the boron injection tank boron concentration Technical Specification for BVPS Unit 1 only; and

(d) renaming the boron injection tank flow path Technical Specification for BVPS Unit 1 only.

The administrative Technical Specification changes requested include:

(a) removal of the amendment number from the operating license for each unit; and

(b) correction of an inconsistency regarding a referenced permissive for BVPS Unit 1 only.

The proposed EPU Technical Specification changes also result in modifications to the Technical Specification Bases and Licensing Requirements Manual (LRM). These modifications are related to the revised analysis at the EPU conditions, including full implementation of the Alternative Source Terms (AST) methodology, and the necessary proposed changes to the Technical Specifications. The proposed Technical Specification Bases and LRM changes are provided for completeness and information only. They are summarized below, but are not discussed further.

(a) adding a definition of RATED THERMAL POWER to the LRM;

(b) revising response times and time constants for various reactor trip system instrumentation;

(c) revising various departure from nucleate boiling parameters;

(d) changing the reference power levels in the leading edge flow meter licensing requirement;

(e) modifying the reactor core safety limit figure;

(f) adding a reference to Westinghouse letter FENOC-02-304 to the Bases of TS 3.4.5;

(g) revising the TS Bases for TS 3.7.1.2, Auxiliary Feedwater System, and TS 3.7.7, Control Room Habitability System;

(h) revising the Effective Full Power Years for the reactor coolant system heatup and cooldown curves for Unit 1 only; and

(i) revising the TS Bases and LRM to reflect the full implementation of the AST methodology.

2.0 PROPOSED CHANGES

The proposed Technical Specification (TS) changes, which are submitted for NRC review and approval, are provided in Attachments A-1 and A-2 for Unit Nos. 1 and 2, respectively. The changes proposed to the Technical Specification Bases are provided in Attachments B-1 and B-2 for Unit Nos. 1 and 2, respectively. The changes proposed to the Licensing Requirements Manual (LRM) are provided in Attachments C-1 and C-2 for Unit Nos. 1 and 2, respectively. Attachment D provides a list of commitments associated with this submittal.

The proposed Technical Specification Bases and LRM changes do not require NRC approval. The Beaver Valley Power Station Technical Specification Bases Control Program controls the review, approval and implementation of Technical Specification Bases changes. The BVPS Licensing Document Control Program controls the review, approval and implementation of LRM changes. The Technical Specification Bases and LRM changes are provided for information only.

The proposed changes to the Technical Specifications, TS Bases and LRM have been prepared electronically. Deletions are shown with a strike-through and insertions are shown double-underlined. This presentation allows the reviewer to readily identify the information that has been deleted and added.

To meet format requirements the Index, Technical Specifications, TS Bases and LRM pages will be revised and repaginated as necessary to reflect the changes being proposed by this LAR.

2.1 Pending LARs

Several of the pages affected by this request contain changes from pending LARs. Approval of the pending LARs is expected prior to, or concurrent with, the approval of this request. Therefore, this request includes germane pending LAR pages. The cover page of Attachments A-1, A-2, B-1, B-2, C-1 and C-2 list the pages affected by the pending LARs. The applicable LAR number identifies the page of a pending LAR that is being revised by this request. The applicable pending LARs for Unit 1/Unit 2 are 310/182, 317/190, 318/191, 321/193, 322/NA, 326/177, 327/197, 328/NA and NA/184.

Pending LAR 310/182 is being submitted by FirstEnergy Nuclear Operating Company (FENOC) under separate cover. This LAR changes from the Constant Axial Offset Control methodology to the Relaxed Axial Offset Control methodology for the determination of Axial Flux Difference and Heat Flux Hot Channel Factor $F_Q(Z)$. The pertinent changes made by this LAR appear in Specification 6.9.5.

Pending LAR 317/190 was submitted by FENOC letter L-04-073, dated June 2, 2004. This LAR proposes the necessary changes to reflect conversion of the BVPS containments to an atmospheric design. The pertinent changes made by this LAR appear in the Technical Specifications, the Technical Specification Bases and the LRM.

Pending LAR 318/191 is being submitted by FENOC under separate cover. This LAR proposes use of the Best Estimate Loss of Coolant Accident analysis methodology described in WCAP 12945-P-A, Volume 1 (Revision 2) and Volumes 2 through 5 (Revision 1), "Code Qualification Document for Best Estimate LOCA Analysis" March 1998. The pertinent changes made by this LAR appear in Specification 6.9.5.

Pending LAR 321/193 was submitted by FENOC letter L-04-040, dated March 22, 2004. This LAR revises the Technical Specifications in accordance with Technical Specification Task Force (TSTF) change TSTF-359, Increased Flexibility in Mode Restraints. The pertinent changes made by this LAR appear in the Technical Specifications and the Technical Specification Bases.

Pending LAR 322/NA, which is applicable to BVPS Unit 1 only, was submitted by FENOC letter L-04-009, dated January 27, 2004. This LAR provides for a one cycle only use of Alloy 800 steam generator sleeves. The pertinent changes made by this LAR appear in the Technical Specifications.

Pending LAR 326/177 was submitted by FENOC letter L-04-074, dated June 1, 2004. This LAR proposes BVPS Unit 2 Capsule W Overpressure Protection System Analysis related TS changes. The pertinent changes made by this LAR appear in the Technical Specifications.

Pending LAR 327/197 is being submitted by FENOC under separate cover. This LAR revises the Steam Generator trip setpoints for low-low and high-high water level. The pertinent changes made by this LAR appear in Technical Specification Tables 3.3-1 and 3.3-3 and the LRM.

Pending LAR 328/NA, which is applicable to BVPS Unit 1 only, was submitted by FENOC letter L-04-089, dated June 28, 2004. This LAR provides for a one cycle only use of the W* methodology for steam generator tube sheet inspection. The pertinent changes made by this LAR appear in the Technical Specifications and Bases.

Pending LAR NA/184, which is applicable to BVPS Unit 2 only, was submitted by FENOC letter L-04-094, dated July 23, 2003. This LAR eliminates periodic response time testing for selected sensors and protection channels. The pertinent changes made by this LAR appear in Technical Specification Bases only.

2.2 Supporting LARs

Two of the pending LARs were prepared to support the EPU now being requested. They are 317/190, Conversion to an Atmospheric Containment Design; and 318/191, Best-Estimate Loss-of-Coolant Accident (LOCA) Methodology.

LAR 317/190 proposes changing from a sub-atmospheric to an atmospheric containment design. The analysis documented in LAR 317/190 assumes the EPU power level. The revised containment integrity analyses documented in LAR 317/190 use the MAAP5-DBA Containment Analysis Code, which models the containment and its sub-compartments. LAR 317/190 is also considered pending, because the EPU LAR also modifies some of the Unit 1 pages contained in LAR 317/190.

LAR 318/191 proposes changing to the Westinghouse large break best-estimate loss-of-coolant accident (BELOCA) methodology. The NRC has approved the methodology, but the EPU is the first application of the methodology at BVPS. The BELOCA analysis also assumes an atmospheric containment design. The BELOCA methodology is the latest NRC approved methodology available. The methodology removes excess conservatism contained in the previous methodology, i.e., Appendix K, and provides additional peak cladding temperature (PCT) margin necessary to achieve acceptable LOCA results at the EPU power level.

2.3 Proposed Changes

Changes to the Operating Licenses and the following TSs are being proposed in this request.

Affected Technical Specifications			
No.	**Unit 1**	**Unit 2**	**Title**
1	License page 3	License page 3a	Item 2.C(1) Maximum Power Level
2	License page 3	License page 3a	Item 2.C(2) Technical Specifications
3	1.0	1.0	DEFINITIONS – 1.3 RATED THERMAL POWER
4	2.1.1.1	2.1.1.1	SAFETY LIMITS – REACTOR CORE
5	3.1.2.8	3.1.2.8	REFUELING WATER STORAGE TANK (RWST)
6	3.3.1.1	3.3.1.1	REACTOR TRIP SYSTEM INSTRUMENTATION (Tables 3.3-1 and 4.3-1, FUNCTIONAL UNIT 4, Power Range, Neutron Flux High Negative Rate Trip)
7	3.3.1.1	N/A	REACTOR TRIP SYSTEM INSTRUMENTATION (Table 3.3-1, FUNCTIONAL UNIT 14, Steam Generator Water Level Low-Low)
8	3.3.1.1	N/A	REACTOR TRIP SYSTEM INSTRUMENTATION (Table Notation, Overtemperature/Overpower ΔT)
9	3.3.1.1	N/A	REACTOR TRIP SYSTEM INSTRUMENTATION (Table Notation, Action 8)
10	3.3.2.1	N/A	ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION (Table 3.3-3, Footnote to Steamline Pressure – Low)
11	3.3.2.1	N/A	ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION (Table 3.3-3, FUNCTIONAL UNIT 5.a, Steam Generator Water Level High-High, and 7.a, Steam Generator Water Level Low-Low)

Affected Technical Specifications			
No.	**Unit 1**	**Unit 2**	**Title**
12	3.4.1.3	N/A	REACTOR COOLANT SYSTEM – SHUTDOWN (SR 4.4.1.3.3)
13	3.4.3	3.4.3	REACTOR COOLANT SYSTEM – SAFETY VALVES
14	3.4.5	3.4.5	STEAM GENERATORS
15	3.4.8	N/A	REACTOR COOLANT SYSTEM – SPECIFIC ACTIVITY
16	3.5.1	3.5.1	ACCUMULATORS
17	3.5.4.1.1	N/A	BORON INJECTION TANK ≥ 350°F
18	3.5.4.1.2 3.5.2 3.5.3	N/A N/A N/A	BORON INJECTION TANK < 350°F ECCS SUBSYSTEMS - T_{avg} ≥ 350°F ECCS SUBSYSTEMS - T_{avg} < 350°F
19	3.5.5	3.5.4	SEAL INJECTION FLOW
20	3.7.1.1	3.7.1.1	TURBINE CYCLE – MAIN STEAM SAFETY VALVES (MSSVs)
21	3.7.1.3	3.7.1.3	PRIMARY PLANT DEMINERALIZED WATER (PPDW)
22	3.7.1.4	N/A	PLANT SYSTEMS - ACTIVITY
23	6.9.5	6.9.5	CORE OPERATING LIMITS REPORT (COLR)

The following provides a description and basis for each proposed change.

Change Number 1

This proposed change consists of modifying Operating License item 2.C(1), "Maximum Power Level" for both BVPS units. The Maximum Power Level will be raised to 2900 MWt for both BVPS units.

Basis for Change Number 1

Enclosure 2 provides the technical justification for the proposed Maximum Power Level increase. The analyses documented in Enclosure 2 assume that both BVPS containments have been converted to an atmospheric design, that Unit 1 has the replacement steam generators (Model 54F) installed, that Unit 2 has the original steam generators (Model 51M), and full implementation of the AST methodology.

Change Number 2

This proposed change consists of a modification to Operating License item 2.C(2), "Technical Specifications" for both BVPS units. The modification is the deletion of the Amendment number. It is requested that the Amendment number field in item 2.C(2) be left blank for all future BVPS amendments. There is no corresponding change to the TS Bases or LRM for this change.

Basis for Change Number 2

This change is not related to the EPU. Since amendments are not always implemented in numerical order, specifying the most recently issued amendment number could lead to confusion. BVPS maintains a License Amendment Status table at the beginning of each unit's Technical Specifications. This table provides the implementation history of each amendment. The existence of this table provides a clear indication of the most current amendment and eliminates the need to continuously update item 2.C(2) of the Operating Licenses. This change is considered administrative in nature and thus does not require any additional discussion or justification.

Change Number 3

This proposed change is a modification to the definition of RATED THERMAL POWER (RTP) and is applicable to both BVPS units. The modification reflects the change in Maximum Power Level described in Change Number 1 by limiting RTP to a maximum value 2900 MWt and allows for specification of an interim RTP value in the LRM. The proposed change consists of permitting an interim RTP value to be specified in the LRM and limiting the maximum RTP to 2900 MWt. There is no corresponding change to the TS Bases for this change.

Basis for Change Number 3

Since the implementation of the BOP modifications that support plant operations at the EPU power level may occur in stages, due to future economical conditions, it is prudent to provide some flexibility in the TS definition of RTP. This is achieved by modifying the TS definition of RTP to limit RTP to a maximum of 2900 MWt, allowing for the specification of an interim value in the LRM, and controlling changes to the interim value by the BVPS 10 CFR 50.59 process. The revised TS definition refers the user to the LRM for the interim value of RTP. This is a departure from the standard definition of RTP, but it retains the goals of the definition, i.e., specifying what RTP is and establishing an upper limit. The revised TS definition states that RTP shall not exceed 2900 MWt, which will be the licensed power level following approval of this EPU amendment request. The new LRM definition, i.e. 1.0.1.a, links to the TS definition and specifies an interim value of RTP. When various BOP modifications have been completed, the interim value of RTP in the LRM may be changed under the 10 CFR 50.59 process. With the proposed changes, all TS and LRM requirements (setpoints, surveillance requirements, actions, applicabilities, etc.) that are keyed to a percentage of RTP can be properly adjusted to the 100% RTP value specified in the LRM as the plant implements the BOP modifications that support operation from the pre-EPU level of 2689 MWt to the EPU level of 2900 MWt. This will ensure that the plant is operating within its approved safety analyses. These proposed administrative controls assure the safe operation of the plant. Section 4.1.1 of this Enclosure provides an assessment of the proposed change to the criteria of 10 CFR 50.36.

Change Number 4

This proposed change is a modification to Technical Specification 2.1.1.1, "SAFETY LIMITS – REACTOR CORE" and is applicable to both BVPS units. The modification consists of specifying the departure from nucleate boiling ratio (DNBR) for two different departure from nucleate boiling (DNB) correlations. For Vantage 5 (V5H) fuel assemblies, the correlation is WRB-1 and the DNBR shall be maintained ≥ 1.17. For Robust Fuel Assemblies (RFA), the correlation is WRB-2M and the DNBR shall be maintained ≥ 1.14. This proposed change is reflected in the TS Bases and LRM.

The TS Bases is further modified by adding a reference to the Revised Thermal Design Procedure (RTDP) and the applicable correlations (WRB-1, WRB-2 and WRB-2M) for DNBR analyses. A discussion of the application of the Standard Thermal Design Procedure (STDP) and the applicable correlations (W-3 and WRB-1) is also provided. The reference to RTDP and the discussion of the application of STDP do not require any change to the TS or LRM. This information is added to provide clarification regarding the application of these two methodologies. The inclusion of the reference to the W-3 and WRB-2 correlations is conservative with respect to the fuel assembly specific DNBR limits of Technical Specification 2.1.1.1.

As part of this change, TS 6.9.5 is also modified by adding WCAP-15025-P-A, "Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids," (Reference 2) to the list of approved methodologies.

Basis for Change Number 4

This change is being made to support enhanced fuel performance in support of the EPU. Presently Technical Specification 2.1.1.1 for each unit only specifies the WRB-1 correlation and its associated limit on DNBR. The WRB-1 correlation is applicable for both V5H and RFA fuel assemblies, but is conservative for the RFA assemblies. In support of the EPU, each unit's core may contain solely RFA fuel assemblies, or a mixture of RFA fuel assemblies and previously burned V5H fuel assemblies. With the proposed change, Technical Specification 2.1.1.1 will provide a fuel assembly specific DNBR limit and the applicable correlation.

Section 6.1 of Enclosure 2 provides the thermal-hydraulic analyses associated with the TS Bases changes associated with the use of STDP, RTDP and the W-3, WRB-2 and WRB-2M correlations. The analyses performed demonstrate that the RFA and V5H fuel assemblies are hydraulically compatible, and that sufficient DNBR margin is available.

The addition of WCAP-15025 to TS 6.9.5 is necessitated by the inclusion of the WRB-2M correlation in TS 2.1.1.1.

Change Number 5

This proposed change is a modification to Technical Specification 3.1.2.8, "REFUELING WATER STORAGE TANK (RWST)" and is applicable to both BVPS units. The modification consists of raising the maximum refueling water storage tank (RWST) solution temperature to 65°F for both BVPS units. With the modification, both BVPS units will have the same maximum RWST solution temperature. There is no corresponding change to the TS Bases or LRM for this change.

Basis for Change Number 5

License Amendment Requests 317 and 190 for Units 1 and 2 (Reference 3) respectively, provide the technical justification for the proposed change to the maximum RWST solution temperature. This change is consistent with analysis inputs for containment conversion and the EPU. The revised temperature supports adequate containment depressurization capability, emergency core cooling system (ECCS) performance and radiological consequences. This change will increase the RWST operating band at the EPU conditions.

Change Number 6

This proposed change is a modification to Technical Specification 3.3.1.1, "REACTOR TRIP SYSTEM INSTRUMENTATION" and is applicable to both BVPS units. The modification consists of deleting Item 4, Power Range, Neutron Flux High Negative Rate, from Tables 3.3-1 and 4.3-1. This proposed change is reflected in the TS Bases and the LRM.

Basis for Change Number 6

This change is not related to the EPU. The technical justification for the deletion of the Power Range, Neutron Flux High Negative Rate trip is provided in WCAP-11394-P-A, "Methodology for the Analysis of the Dropped Rod Event" (Reference 4). Approval for the methodology described in Reference 4, and subsequent approval for elimination of the trip, is documented in the NRC Safety Evaluation Report of WCAP-11394, (Reference 5). The trip is not credited in the EPU analysis documented in Enclosure 2 because, as stated in Reference 5, no credit is taken for any direct reactor trip due to the dropped rod cluster control assembly (RCCA) event or for automatic power reduction due to dropped RCCA(s).

Change Number 7 (Unit 1 only)

This proposed change is a modification to Technical Specification 3.3.1.1, "REACTOR TRIP SYSTEM INSTRUMENTATION" and is applicable to BVPS Unit 1 only. The modification consists of revising the value for Functional Unit 14, Steam Generator Water Level Low-Low, in Table 3.3-1 to reflect the replacement steam generators. This proposed change is reflected in the LRM. There is no corresponding change to the TS Bases.

Basis for Change Number 7

Section 5.10 of Enclosure 2 provides the technical justification for proposed setpoint changes. The Unit 1 Model 54F replacement steam generators (RSG) incorporate a narrow range span (NRS) of 212 inches, which is larger than the Unit 1 Model 51 original steam generators (OSG) narrow range span of 144 inches. The RSG nominal indicated water level is 65% NRS, compared to the OSG nominal indicated water level of 44% NRS. These design and operating differences necessitated that the low-low water level setpoint and allowable value be revised.

Change Number 8 (Unit 1 only)

This proposed change modifies Technical Specification 3.3.1.1, "REACTOR TRIP SYSTEM INSTRUMENTATION" and is applicable to BVPS Unit 1 only. The first part of the change consists of modifying the equation shown on page 3/4 3-5 for Overtemperature ΔT, and the equation shown on page 3/4 3-5a for Overpower ΔT. The function generated by the lag compensator for ΔT and the function generated by the lag compensator for T_{avg} is added to each of these equations. These added functions contain new time constants, namely τ_4 and τ_5. The values of these time constants are added to the LRM as part of the proposed change. There is no corresponding change to the TS Bases for this part of the change. The second part of the change is the deletion of the BVPS Unit 1 TS Bases statement that the Overpower ΔT trip is not credited. The trip is credited in the EPU analyses for both BVPS units. There is no corresponding change to the TS or LRM for this part of the change.

Basis for Change Number 8

Sections 3.2.1 and 5.3 of Enclosure 2 provide the technical justification for the proposed change to the generated functions and time constants identified above. The changes are being proposed to optimize operating margins at the EPU conditions. The evaluation documented in Enclosure 2 demonstrates that the plant operating margins are adequate for the EPU conditions. As stated in Section 5.3.19 of Enclosure 2, the Overpower ΔT trip is credited in the EPU full power steamline break analyses for both BVPS units.

Change Number 9 (Unit 1 only)

This proposed change is a modification to Technical Specification 3.3.1.1, "REACTOR TRIP SYSTEM INSTRUMENTATION" and is applicable to BVPS Unit 1 only. The change consists of modifying Action 8 on page 3/4 3-7. The permissive specified in Action 8 will be changed from P-7 to P-9. There is no corresponding change to the TS Bases or LRM for this change.

Basis for Change Number 9

This change is not related to the EPU and is applicable to BVPS Unit 1 only. The change is being made to correct an existing inconsistency in the BVPS Unit 1 TS.

When BVPS Unit 1 was originally licensed in 1976 a turbine trip caused a direct reactor trip when operating above P-7. At that time Action 8 to TS 3.3.1.1, Table 3.3-1, Item 18.B, "Turbine Stop Valve Closure" was correct in referencing P-7. In 1978, LAR 35 was submitted for BVPS Unit 1. This LAR requested changing the reactor trip on turbine trip from P-7 to P-9. However, LAR 35 did not identify changing from P-7 to P-9 in Action 8 of Table 3.3-1. When the License Amendment 62 (Reference 6) was approved in 1983, the proposed changes were incorporated into the BVPS Unit 1 TSs, but they did not include the change from P-7 to P-9 in Action 8 of Table 3.3-1. It is noted that, while Action 8 has always stated P-7 versus P-9, the use of P-7 has been conservative since the P-7 setpoint (10 % RTP) is much less than the P-9 setpoint (49 % RTP). It is also noted that Action 8 of Table 3.3-1 for BVPS Unit 2 correctly references P-9. The proposed change is considered administrative since it corrects an inconsistency between the above action statement and BVPS Unit 1 Amendment 62 and thus does not require any additional discussion or justification.

Change Number 10 (Unit 1 only)

This proposed change is a modification to Technical Specification 3.3.2.1, "ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION." The proposed change is applicable to BVPS Unit 1 only. The proposed change consists of adding a footnote to all references to Steamline Pressure – Low in Table 3.3-3. The footnote provides information regarding the time constants utilized in the lead-lag controllers for Steamline Pressure - Low. There is no corresponding change to the TS Bases for this change. The proposed change is reflected in the LRM.

Basis for Change Number 10

The proposed change provides consistency with the companion BVPS Unit 2 Technical Specification and the values appearing in Tables 5.3.1-3A and 5.6.2-4 of Enclosure 2. This change is considered administrative in nature and thus does not require any additional discussion or justification.

Change Number 11 (Unit 1 only)

This proposed change is a modification to Technical Specification 3.3.2.1, "ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION" and is applicable to BVPS Unit 1 only. The modification consists of revising the values for Functional Units 5.a, Steam Generator Water Level High-High, and 7.a, Steam Generator Water Level Low-Low, in Table 3.3-3 to reflect the replacement steam generators. This proposed change is reflected in the LRM. There is no corresponding change to the TS Bases for this change.

Basis for Change Number 11

Section 5.10 of Enclosure 2 provides the technical justification for proposed setpoint changes. The Unit 1 RSG incorporates a narrow range span (NRS) of 212 inches, which is larger than the Unit 1 OSG narrow range span of 144 inches. The RSG nominal indicated water level is 65% NRS, compared to the OSG nominal indicated water level of 44% NRS. These design and operating differences necessitated that the low-low and high-high water level setpoints and allowable values be revised.

Change Number 12 (Unit 1 only)

This proposed change is a modification to Technical Specification 3.4.1.3, "REACTOR COOLANT SYSTEM – SHUTDOWN" and is applicable to BVPS Unit 1 only. The modification consists of revising the steam generator secondary side level requirement in Surveillance Requirement 4.4.1.3.3 from 12% to 28% to reflect the replacement steam generators. There is no corresponding change to the TS Bases or LRM for this change.

Basis for Change Number 12

Section 4.7.1 of Enclosure 2 provides the technical justification for the proposed change in Surveillance Requirement 4.4.1.3.3. The Unit 1 RSG incorporates a NRS of 212 inches, which is larger than the Unit 1 OSG narrow range span of 144 inches. In order to obtain the larger span, the NRS lower level tap is located in the transition cone below the top of the tube bundle. These design differences necessitated that the TS level used to verify operability of the reactor coolant loops be revised.

Change Number 13

This proposed change is a modification to Technical Specification 3.4.3, "REACTOR COOLANT SYSTEM-SAFETY VALVES" and is applicable to both BVPS units. The modification consists of changing the positive tolerance for the pressurizer code safety valves from +1% to +3% for BVPS Unit 1, and from +1% to +1.6% for BVPS Unit 2. There is no corresponding change to the TS Bases or LRM for this change.

Basis for Change Number 13

Section 5.3.6 of Enclosure 2 provides the technical justification for the proposed change to the positive tolerance for the pressurizer code safety valves. These changes are made to increase the pressurizer code safety valves lift setting tolerances as justified by the analyses performed for the EPU.

Change Number 14

These proposed changes are modifications to Technical Specification 3.4.5, "STEAM GENERATORS" and are applicable to both BVPS units, but are described separately for each unit. To facilitate the description of the proposed changes to TS 3.4.5, Change Number 14 is divided into two parts. Change Number 14-1 covers the Unit 1 changes and Change Number 14-2 covers the Unit 2 changes.

Change Number 14-1 (Unit 1)

The proposed changes to BVPS Unit 1 TS 3.4.5 consist of removing references to steam generator tube repair and sleeving.

Basis for Change Number 14-1 (Unit 1)

Section 4.7.1 of Enclosure 2 provides a discussion of the BVPS Unit 1 replacement steam generators. The Westinghouse Model 51 OSGs will be replaced with Westinghouse Model 54F RSGs during refueling outage 1R17. The Model 54F RSGs employ a number of design enhancements relative to the Model 51 OSGs, including different tubing material, a different tube support plate design and a different tube-to-tubesheet joint. As a result of these design differences, the Model 51 OSG analyses performed to support the use of voltage-based repair criteria on tube-to-tube support plate intersections and the use of tube repair by ABB Combustion Engineering TIG welded and Westinghouse laser welded sleeving are not applicable to the Model 54F RSGs. Therefore, changes to the steam generator tube inspection surveillance requirements are necessary to remove the provisions allowing use of voltage-based repair criteria, TIG welded sleeving, and laser welded sleeving.

Other changes are also proposed to clarify the inservice inspection schedule as it pertains to Model 54F RSGs and to clarify wording and promote consistency with the EPRI Technical Report No. 1003138, Revision 6, "PWR SG Examination Guidelines," October 2002 (Reference 7) and NEI 97-06, Revision 1, "Steam Generator Program Guidelines," January 2001 (Reference 8). The proposed change is reflected in the TS Bases. There is no corresponding change to the LRM for this change.

Change Number 14-2 (Unit 2)

The Unit 2 changes to TS 3.4.5 are made in two parts. The first part consists of changing the revision number of WCAP-13483, "Beaver Valley Units 1 and 2 Westinghouse Series 51 Steam Generator Sleeving Report, Laser

Welded Sleeves" from Revision 1 to Revision 2 (Reference 9). The second part consists of changing the repair limit for TIG welded steam generator sleeves. The TS Bases is also changed by adding a reference to Westinghouse letter FENOC-02-304. There is no corresponding change to the LRM for these changes.

Basis for Change Number 14-2 (Unit 2)

Section 4.7.2.4.6 of Enclosure 2 provides the technical justification for laser welded sleeves. Updating the WCAP to Revision 2 documents the acceptability of the laser welded sleeve design as an acceptable repair methodology for BVPS Unit 2 at the EPU conditions. The repair limit for laser welded sleeves is not being changed.

Section 4.7.2.4.7 of Enclosure 2 provides the technical justification for the change to the TIG welded steam generator sleeve repair limit.

Change Number 15 (Unit 1 only)

This proposed change consists of a modification to Technical Specification 3.4.8, "REACTOR COOLANT SYSTEM – SPECIFIC ACTIVITY" and is applicable to BVPS Unit 1 only. The modification consists of revising the value for the primary side coolant system specific activity to reflect the replacement steam generators. This proposed change is reflected in the Technical Specification Bases.

Basis for Change Number 15

The primary coolant system specific activity is limited to ensure that the offsite and control room operator doses due to a main steam line break or a steam generator tube rupture will not exceed the applicable limits. The original stringent specific activity limit of 0.1 μCi/gm Dose Equivalent I-131 was necessary because of adoption of the Alternate Repair Criteria (ARC) and the associated Accident Induced Leakage, which had to be taken into account in a main steam line break accident. With the Unit 1 RSG, the ARC methodology is not utilized and the Accident Induced Leakage is no longer required. The primary coolant system specific activity can be increased to 0.35 μCi/gm Dose Equivalent I-131 without jeopardizing the radiological consequences. The technical justification for the proposed change is provided in Section 5.11.9 of Enclosure 2. The proposed change will make the BVPS Unit 1 Technical Specification limits consistent with the BVPS Unit 2 Technical Specification limits.

Change Number 16

This proposed change consists of modifications to Technical Specification 3.5.1, "ACCUMULATORS" and is applicable to both BVPS units. The first part of the change consists of changing the limits on the accumulator water volume and nitrogen cover pressure. The second part consists of replacing the word "contained" with "usable" in surveillance 4.5.1.a.1. The third part consists of providing the minimum and maximum accumulator volumes in percent indicated level in addition to gallons.

For BVPS Unit 1 the accumulator water volume is changed from between 7664 and 7816 gallons to between 6681 gallons (0% indicated level) and 7645 gallons (100% indicated level). The nitrogen cover pressure is changed from between 605 psig and 661 psig to between 561 psig and 685 psig.

For BVPS Unit 2 the accumulator water volume is changed from between 7532 and 7802 gallons to between 6898 gallons (0% indicated level) and 8019 gallons (100% indicated level). The nitrogen cover pressure is changed from between 585 psig and 665 psig to between 561 psig and 685 psig.

The TS Bases for both units has been modified to state that the TS limits for accumulator water volume, boron concentration and minimum nitrogen cover pressure are analysis values, that the percent indicated level does not include instrumentation uncertainty and that the maximum nitrogen cover pressure TS limit preserves accumulator integrity. There are no corresponding changes to the LRM for these changes.

Basis for Change Number 16

Sections 5.2.1 and 5.2.2 of Enclosure 2 provide the technical justification for the proposed change to the accumulator limits on water volume and nitrogen cover pressure. These changes are consistent with analysis inputs and provide the necessary operating margin at the EPU conditions. Changing the surveillance to address the usable volume is consistent with the new volume limits. Differences in the two unit's accumulator instrumentation taps and standpipes result in a different number of gallons for 0% and 100% indicated level for each unit. The addition of percent indicated level is an administrative enhancement to aid the operators since the control board indication is in percent level. This is also consistent with the NUREG-1431, Revision 3, "Standard Westinghouse Technical Specifications Westinghouse Plants", June 2004 (Reference 10) and requires no further discussion.

Change Number 17 (Unit 1 only)

This proposed change is a modification to Technical Specification 3.5.4.1.1, "Boron Injection Tank ≥ 350°F." The proposed change is applicable to BVPS Unit 1 only. The modification consists of deleting Technical Specification 3.5.4.1.1. The proposed change is reflected in the TS Bases. There are no corresponding changes to the LRM for this change.

Basis for Change Number 17

As stated in Sections 5 and 9.4.1 of Enclosure 2, the boron concentration requirement for the BVPS Unit 1 boron injection tank (BIT) may be removed because the BIT was not credited as a source of borated water in the EPU analysis. Section 4.1.11 of this Enclosure provides further technical justification for the deletion of TS 3.5.4.1.1.

Change Number 18 (Unit 1 only)

This proposed change is a modification to Technical Specification 3.5.4.1.2, "Boron Injection Tank < 350°F." The proposed change is applicable to BVPS Unit 1 only. The modification consists of renaming and renumbering TS 3.5.4.1.2 to TS 3.5.4, "HHSI FLOW PATH." The modification consists of replacing BIT in the TS title and Limiting Condition for Operation (LCO) with high head safety injection (HHSI) and moving the flow path isolation requirements to the TS Bases. The Applicability of TS 3.5.4 is also changed to match the Applicability of TS 3.4.9.3, "Reactor Coolant System Overpressure Protection System."

This change requires changes to TS 3.5.2, "ECCS SUBSYSTEMS - $T_{avg} \geq$ 350°F" and TS 3.5.3, "ECCS SUBSYSTEMS - $T_{avg} < 350$°F." The change to TS 3.5.2 involves adding Note (2) to allow the HHSI flow path to be isolated when transitioning into or out of the Applicability of TS 3.5.4. The change to TS 3.5.3 involves modifying Surveillance Requirement 4.5.3.1 to address only those Surveillance Requirements from TS 3.5.2 that are applicable to TS 3.5.3.

The proposed changes are reflected in the TS Bases for the modified TS and TS 3.4.9.3. There are no corresponding changes to the LRM for these changes.

Basis for Change Number 18

The title change and renumbering of TS 3.5.4.1.2 is being done to reflect Change Number 17 where Technical Specification 3.5.4.1.1, "Boron

Injection Tank ≥ 350°F", is being deleted. The purpose of TS 3.5.4.1.2 is to prevent a potential overpressurization due to an inadvertent safety injection signal when the RCS temperature is below the overpressure protection systems (OPPS) enable temperature. This is achieved by isolating the BIT flow path when below the OPPS enable temperature. Since the BIT is no longer credited as a source of boron, its mention in the high head safety injection flow path is inconsequential from an accident mitigation aspect.

The addition of Note (2) to TS 3.5.2 is being made to permit an orderly transition into and out of the Applicability of TS 3.5.4. The addition of Note (2) provides the same transitioning flexibility as Note (1), which pertains to charging pump injection capability. The modification to Surveillance Requirement 4.5.3.1 is being made to eliminate the requirements that are not required in Mode 4.

Change Number 19

This proposed change consists of a modification to Technical Specification 3.5.5, "EMERGENCY CORE COOLING SYSTEMS - SEAL INJECTION FLOW" and is applicable to both BVPS units. The modification consists of raising the minimum value of the charging pump discharge pressure for reactor coolant pump (RCP) seal injection flow. This proposed change is reflected in the Technical Specification Bases. There is no corresponding change to the LRM for this change.

Basis for Change Number 19

The purpose of the change is to increase the analytical resistance used for the seal injection flow path in the calculation of safety injection flow for the EPU conditions. Section 9.2.3 of Enclosure 2 provides the technical justification for the proposed change. The more conservative pressure is used for both units to provide consistency between the two units.

Change Number 20

This proposed change is a three part modification to Technical Specification 3.7.1.1, "TURBINE CYCLE – MAIN STEAM SAFETY VALVES (MSSVs)" and is applicable to both BVPS units. The first part of the modification consists of changing the maximum percent of RTP in action "a", from 61 percent to 57 percent. The second part consists of changing the values in the Maximum Allowable Power column of Table 3.7-1 from 58, 41 and 24 to 50, 34 and 19. The third part consists of a modification to Table 3.7-2 where the MSSV with the lowest setting pressure is limited to a lift setting tolerance of +1 percent and -3 percent and the lift setting tolerance for the remaining MSSVs is changed to ± 3 percent. These proposed changes are reflected in the TS Bases along with associated changes to the percent relief capacity of the MSSVs and the percent power reduction assumed to account for Nuclear Instrumentation System trip channel uncertainties. There are no corresponding changes to the LRM for these changes.

Basis for Change Number 20

The Technical Specification Bases for TS 3.7.1.1 describes and provides the equation and relationships that are used to calculate the maximum percent of RTP in action "a", and the Maximum Allowable Power values provided by Table 3.7-1. This is the methodology that was used to develop the proposed changes for those parameters. Sections 5.3.6, 5.3.7 and 9.10.1 of Enclosure 2 describe the analyses supporting changing the positive tolerance limit for the MSSVs. These changes are made to increase the operating margin at the EPU conditions. Section 3.1.4 of Enclosure 2 provides the technical justification for the Maximum Allowable Power values provided in Table 3.7-1.

Although the loss of external electrical load and/or turbine trip safety analysis demonstrates that the MSSVs are acceptable for EPU conditions with a lift setting tolerance of ±3%, the MSSV with the lowest setting pressure is limited to a lift setting tolerance of +1%/-3% due to the small break LOCA safety analysis. Section 9.10.1 of Enclosure 2 provides the technical justification for the lift setting tolerance of +1%/-3% for the lowest MSSV.

Change Number 21

This proposed change consists of modifications to Technical Specification 3.7.1.3 "PRIMARY PLANT DEMINERALIZED WATER (PPDW)" and is applicable to both BVPS units. The modifications consist of replacing the word "contained" with "usable" in the Limiting Condition for Operation statement for Unit 1; revising the Unit 1 action statement to be consistent with Unit 2; changing the value of the minimum volume for each unit; and relocating the Unit 2 TS footnote stating that the volume is an analysis value to the Bases. The TS Bases is revised to provide consistency between the two units. There is no corresponding change to the LRM for this change.

Basis for Change Number 21

All of the changes to Technical Specification 3.7.1.3 are considered editorial except the change to the volume. The change in volume is being made to specify that the required minimum volume is the usable volume. The required usable volume for EPU conditions is justified in Section 3.1.4.4 of Enclosure 2. The other changes are being made to correct inconsistencies between the TS itself and its Bases, to relocate information to the TS Bases, and to provide consistency between the two units' TS.

The TS Bases for Technical Specification 3.7.1.3 is being modified. The modifications consist of stating that the required minimum volume is the usable volume. For Unit 2 the TS footnote stating that the minimum volume is an analysis value is relocated to the TS Bases and modified. For consistency, this statement is added to the Unit 1 TS Bases. A statement regarding the cooldown capability of the tank is deleted from the Unit 1 TS Bases to provide consistency with the Unit 2 TS Bases. With this change the TS Bases for both BVPS units reflect the analyzed capability of the tank.

With these changes the TS Limiting Condition for Operation statements for both BVPS units will be consistent with their TS Bases, and there will be consistency between the TS and TS Bases for both units.

Change Number 22 (Unit 1 only)

This proposed change consists of a modification to Technical Specification 3.7.1.4, "PLANT SYSTEMS – ACTIVITY" and is applicable to BVPS Unit 1 only. The modification consists of revising the value for secondary side coolant system specific activity. There is no corresponding change to the TS Bases or LRM for this change.

Basis for Change Number 22

This change is the result of Change Number 15. The change will provide consistency with the Standard Technical Specifications and the BVPS Unit 2 TS.

Change Number 23

This proposed change consists of adding WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis", (Reference 11) to the list of NRC approved methodologies in Technical Specification 6.9.5, "CORE OPERATING LIMITS REPORT (COLR)".

Basis for Change Number 23

This LAR is requesting NRC approval to use the VIPRE computer code at BVPS. The code is used for departure from nucleate boiling (DNB) analysis for those Updated Final Safety Analysis Report (UFSAR) transients and accidents for which DNB might be a concern. The EPU analysis is the first application of the VIPRE computer code at BVPS. Since NRC approval to use VIPRE at BVPS is being requested and TS 6.9.5.b lists approved methodologies, WCAP-14565-P-A is being added to the listing of NRC approved methodologies appearing in TS 6.9.5.b. There is no corresponding change to the TS Bases or LRM for this change.

3.0 BACKGROUND

The Beaver Valley Power Station units were originally licensed to a Maximum Power Level of 2652 MWt. In September of 2001 License Amendments 243 (Unit 1) and 122 (Unit 2) were issued, granting permission to increase the Maximum Power Level by approximately 1.4% to 2689 MWt (Reference 12). This LAR is requesting an Extended Power Uprate (EPU) of approximately an additional 8 percent to 2900 MWt for both units.

Section 2.0 of this Enclosure discusses the Technical Specification changes proposed for the EPU and others that are not a direct result of the requested EPU. The following provides a background discussion of the Technical Specification systems, components and parameters affected by the proposed changes. The discussion is provided for information and does not describe the changes being proposed.

3.1 Rated Thermal Power

Definition 1.3 of the Technical Specifications defines Rated Thermal Power (RTP) as the total reactor core heat transfer rate to the reactor coolant. The value of RTP is also specified in Definition 1.3 and is equal to the maximum power level in the Operating License.

3.2 Fuel Assemblies

The reactor core includes uranium dioxide pellets, enclosed in ZIRLO™ or Zircaloy tubes with welded end plugs, as fuel. The tubes are supported in assemblies by structures of spring clip grids and suitable end pieces for the support of the assembled rods and restraint of abnormal axial movement. The mechanical control rods consist of clusters of stainless steel clad absorber rods, which are guided by tubes located within the fuel assembly. The core consists of these fuel assemblies, loaded in three different burnup enrichment regions (i.e., fresh fuel, once burned and second/third burned). The fuel assemblies are designed to perform satisfactorily through their lifetime.

To support the EPU the fuel assembly design was changed from the Vantage 5H (V5H) design to the Robust Fuel Assembly (RFA) design with Intermediate Flow Mixing (IFM) grids. The BVPS cores are in the process of being transitioned from V5H to RFA fuel assemblies. This transition will be completed before the requested amendment implementation date.

3.3 Refueling Water Storage Tank

The refueling water storage tank (RWST) is a vertical flat-bottomed cylindrical tank with a dome head and is mounted on and secured to a reinforced concrete foundation and fabricated of stainless steel. The normal operating function of the RWST is to contain the water required for filling both the refueling cavity and the fuel transfer canal. The water in the RWST is borated to the concentration range specified in Technical Specifications. A manhole is provided for internal inspection of the tank during the refueling period. During normal operation the RWST is maintained within the volume range specified in Technical Specifications.

The tank is also used to supply water to certain engineered safety features; therefore, it is designed as a Category I component to withstand seismic loading. An evaluation is made to ensure no loss of function following the hypothetical earthquake conditions. The connecting piping is designed to withstand seismic loading to ensure the functioning of the system.

3.4 Power Range, Neutron Flux High Negative Rate Trip

The negative rate trip was the reactor protection trip system functional unit that provided protection for a dropped RCCA. The dropped RCCA event was the only UFSAR event that credited the negative rate trip.

3.5 Overtemperature ΔT and Overpower ΔT

The Overtemperature ΔT trip protects the core against low DNBR and trips the reactor on coincidence as given in the Technical Specifications with one set of temperature measurements per loop. The setpoint for the trip is continuously calculated by analog circuitry for each loop by solving the equation found in Technical Specification Table 3.3-1.

The Overpower ΔT trip protects against excessive power and trips the reactor on coincidence as given in the Technical Specifications with one set of temperature measurements per loop. The setpoint for each channel is continuously calculated by analog circuitry for each loop by solving the equation found in Technical Specification Table 3.3-1.

The factors included in establishing the Overtemperature ΔT and Overpower ΔT trip setpoints include the reactor coolant temperature in each loop. The axial distribution of core power (based on indicated difference between the two section excore neutron detectors) is also a factor in calculating the Overtemperature ΔT setpoint. A region of permissible core operation may be defined in terms of power, axial power distribution, and coolant flow and temperature. The protection system monitors these process variables (as well as many other process and plant variables). If the region limits are approached during operation, the protection system will automatically actuate alarms, initiate load cutback, prevent control rod withdrawal and/or trip the reactor.

Operation within the permissible region and complete core protection is ensured by the Overtemperature ΔT and Overpower ΔT reactor trips in the system pressure range defined by the Pressurizer High Pressure and Pressurizer Low Pressure reactor trips, provided that the transient is slow with respect to piping delays from the core to the temperature sensors. High Nuclear Flux and Low Coolant Flow reactor trips provide core protection in the event that a transient faster than the ΔT responses occurs. Finally, thermal transients are anticipated and avoided by reactor trips actuated by turbine trip and primary coolant pump motor low frequency or low voltage on 2 out of 3 buses.

3.6 Pressurizer Safety Valves

The reactor coolant system is protected against overpressure by safety valves located on the top of the pressurizer. The safety valves on the pressurizer are sized to prevent system pressure from exceeding the design pressure by more than 10 percent, in accordance with Section III of the ASME Boiler and Pressure Vessel Code. The capacity of the pressurizer safety valves is determined from considerations of: (1) the reactor protection system, and (2) accident or transient conditions which may potentially cause overpressurization of the reactor coolant system.

The combined capacity of the safety valves is sufficient to prevent system pressure from exceeding the design pressure by more than 10 percent following a complete loss of load without a direct reactor trip or any other control, except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve setting.

3.7 Accumulators

The accumulators are carbon steel vessels, clad with stainless steel and designed to ASME Boiler and Pressure Vessel Code, Section III, Class C requirements. Redundant level and pressure indicators are provided with readouts on the control board. Each channel is equipped with high and low level alarms. The margin between the minimum operating pressure and design pressure provides a range of acceptable operating conditions within which the accumulator system meets its design core cooling objectives. The band is sufficiently wide to permit the operator to minimize the frequency of adjustments in the amount of contained gas or liquid to compensate for leakage. Limiting conditions for operation and surveillance are set forth in the Technical Specifications.

The accumulators are filled with borated water and pressurized with nitrogen gas. During normal operation, each accumulator is isolated from the RCS by two check valves in series. If the RCS pressure falls below the accumulator pressure, the check valves open and borated water is forced into the RCS. Mechanical operation of the swing-disk check valves by means of differential pressure is the only action required to open the injection path from the accumulators to the core via the cold leg.

The accumulators are passive engineered safety features because the nitrogen gas pressure forces injection; no external source of power or signal transmission is needed to obtain fast acting, high flow capability when the need arises. One accumulator is connected to each of the cold legs of the RCS.

3.8 Boron Injection Tank (Unit 1 only)

The boron injection tank (BIT) is constructed of carbon steel and clad with stainless steel for corrosion resistance. Prior to the removal of the boron concentration requirement for the BIT, the discharge from the high head safety injection pumps provided the motive force to inject the boric acid solution into the RCS. At that time continuous recirculation between the BIT and the boron injection surge tank ensured that the boric acid in the BIT remained in solution at all times.

3.9 Main Steam Safety Valves

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 overpressurizing the reactor coolant pressure boundary (RCPB) by providing a heat sink for the removal of energy from the RCS if the preferred heat sink is not available.

Five MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves. The MSSVs must have sufficient capacity to limit the secondary system pressure to ≤ 110% of the steam generator design pressure in order to meet the requirements of the ASME Code, Section III. The MSSV design includes staggered setpoints so that only the needed valves will actuate. Staggered setpoints reduce the potential for valve chattering that is due to insufficient steam pressure to fully open all valves following a turbine reactor trip.

3.10 Primary Plant Demineralized Water Storage Tank

The primary plant demineralized water storage tank supplies water to the auxiliary feedwater pumps, which supply water to the secondary side of the steam generators. Water for the makeup demineralizer water system is pumped from the demineralizer pump suction tank by either of two inline pumps. The water then flows to the turbine plant demineralized water storage tanks, the primary plant demineralized water storage tank, or the two primary water storage tanks.

3.11 Unit 1 Replacement Steam Generator Setpoints

Steam Generator Water Level – Low-Low

Steam generator low-low water level is a functional unit of the Reactor Trip System (RTS). It functions to trip the reactor and protect the reactor core from a loss of heat sink in the event of a sustained steam/feedwater flow mismatch. This trip is actuated on two-out-of-three low-low water level signals occurring in any steam generator. The basic function of the reactor protection circuits associated with the steam generator low-low water level reactor trip is to preserve the steam generator heat sink for removal of long term core residual heat. Should a complete loss of feedwater occur, the reactor would be tripped on steam generator low-low water level.

A spurious high signal from the feedwater flow channel being used for control would cause a reduction in feedwater flow. The mismatch between steam demand and feedwater flow produced by this spurious signal will actuate alarms to alert the operator of this situation in time for manual correction or, if the condition is allowed to continue, the reactor will eventually trip on a steam generator low-low water level signal independent of indicated feedwater flow.

Steam generator low-low water level is also a functional unit of the Engineered Safety Feature Actuation System (ESFAS). It functions to actuate the auxiliary feedwater (AFW) pumps to provide auxiliary feedwater to the secondary side of the steam generators in order to maintain a heat sink. The turbine driven AFW pump is started on two-out-of-three low-low water level signals occurring in any one steam generator and the motor driven AFW pumps are started on two-out-of-three low-low water level signals occurring in any two steam generators

Steam Generator Water Level – High-High

Steam generator high-high water level is a functional unit of the ESFAS. It functions to trip the turbine and isolate feedwater flow to the steam generators to protect the turbine from excessive moisture carryover caused by steam generator high-high water level. Steam generator high-high water level signals in two-out-of-three channels for any steam generator will actuate a turbine trip, trip the main feedwater pumps, and close the main and bypass feedwater control valves.

A spurious low signal from the feedwater flow channel being used for control would cause an increase in feedwater flow. The mismatch between steam flow and feedwater flow produced by the spurious signal would actuate alarms to alert the operator of the situation in time for manual correction. If the condition is allowed to continue, a two-out-of-three steam generator high-high water level signal from any steam generator independent of the indicated feedwater flow, will cause feedwater isolation, and trip the turbine. If the turbine trip occurs when reactor power is above the P-9 permissive setpoint, the turbine trip will result in a subsequent reactor trip.

Steam Generator Water Level

Steam generator water level is used to verify that the steam generators are operable when in Modes 4 and 5, thereby supporting the operability verification for the reactor coolant system (RCS) coolant loops in Modes 4 and 5. The verification of steam generator level serves to confirm that the steam generators are capable of functioning as a heat sink in Modes 4 and 5 to provide an alternate method for removal of long-term core residual heat. The water level used to verify steam generator operability is selected such that it is above the top of the tube bundle. This ensures that the U-tubes are completely submerged and that the steam generators are capable of functioning as a heat sink in Modes 4 and 5 under either forced circulation or natural circulation conditions.

In the event of a loss of electrical power to the residual heat removal pumps and the reactor coolant pumps when in Modes 4 and 5, steam generators that satisfy this operability requirement will support establishing the natural circulation reactor coolant loop flow necessary for removal of long-term core residual heat for core cooling.

3.12 Steam Generators

The Unit 1 steam generators are Model 54F replacement steam generators (RSGs) designed by Westinghouse. The RSGs are designed and analyzed to industry codes and standards that are, at a minimum, equivalent to the Model 51 original steam generators (OSGs), which were also designed by Westinghouse.

The Unit 2 steam generators are Model 51M original steam generators (OSGs) designed by Westinghouse. They are also designed and analyzed to industry codes and standards.

Sections 4.7.1 and 4.7.2 of Enclosure 2 provide a brief description of each unit's steam generators, including design and analysis provisions in the areas of thermal-hydraulic performance, structural integrity, U-bend fatigue, tube wear, tube plugging limit, and tube degradation.

3.13 Seal Injection Flow

The purpose of the TS limit on seal injection flow is to limit the flow through the reactor coolant pump (RCP) seal water injection line following a safety injection (SI) actuation signal so that sufficient centrifugal charging pump safety injection flow is directed to the reactor coolant system (RCS) via the safety injection points. The limit is not strictly a flow limit, but rather a flow limit based on a flow line resistance. In order to establish the proper flow line resistance, a pressure and flow must be known. The flow line resistance is determined by assuming that the RCS pressure is at normal operating pressure and that the centrifugal charging pump discharge pressure is greater than or equal to the value specified in the TS. The centrifugal charging pump discharge header pressure remains essentially constant through the applicability of the TS. A reduction in RCS pressure would result in more flow being diverted to the RCP seal injection line than at normal operating pressure. The valve settings established at the prescribed centrifugal charging pump discharge header pressure result in a conservative valve position should RCS pressure decrease. With the discharge pressure and control valve position as specified by the TS, a flow limit is established. It is this flow limit that is used in the accident analyses. The limit on seal injection flow, combined with the centrifugal charging pump discharge header pressure limit and an open wide condition of the seal injection flow control valve, must be met to render the emergency core cooling system (ECCS) operable. If these conditions are not met, the ECCS flow assumed in the accident analyses would not be met.

3.14 Reactor Coolant System Specific Activity

The total effective dose equivalent that an individual at the site boundary can receive for 2 hours during an accident and the total effective dose equivalent that a resident at the low population zone can receive during the course of an accident are specified in 10 CFR 50.67. The TS limits on specific activity ensure that the doses are held to within the limits of 10 CFR 50.67 as allowable by Regulatory Guide 1.183 (Reference 1) during analyzed transients and accidents. The TS limits also ensure that the total effective dose equivalent to a control room operator is within the dose limits set by 10 CFR 50.67. The RCS specific activity limits the allowable concentration level of radionuclides in the reactor coolant The limits are established to ensure that the offsite and control room dose consequences remain within the regulatory limits in the event of a steam generator tube rupture (SGTR) accident or a main steam line break (MSLB) accident.

3.15 Secondary Coolant System Specific Activity

Activity in the secondary coolant results from steam generator tube leakage from the RCS. The limit on secondary coolant specific activity will ensure that the offsite and control room operator dose due to release of secondary coolant activity inventory, (such as that from a dried-out steam generator following a MSLB), in conjunction with other radiological releases resulting from the accident, will not exceed the applicable regulatory limits.

3.16 Welded Steam Generator Sleeves (Unit 2 only)

Laser and TIG welded steam generator sleeves are acceptable techniques to repair steam generator tubes. However, it is necessary to determine and establish an adequate repair limit to determine when a repair should and should not be made. The repair limit is defined as the depth of degradation at or beyond which the tube shall be repaired or removed from service by plugging. The repair limit assumes a tube wall combined allowance for postulated degradation growth and eddy current uncertainty of 20% through-wall per cycle to establish the TS repair limits for the sleeves.

3.17 VIPRE

VIPRE is a subchannel thermal/hydraulic computer code that is typically used to describe the reactor core of a nuclear power plant. The code requires the user to enter the boundary conditions describing the coolant entering the core, the power generation, and the dimensional and material properties of the nuclear fuel. The boundary conditions for coolant entering the core include the inlet flow rate, enthalpy and pressure or the pressure, inlet enthalpy and differential pressure from which the inlet flow rate can be derived. The core power generation input includes spatial as well as temporal options. The code input is versatile and flexible, providing the user with numerous options. These include choices among correlations for heat and mass transfer that are built into the code. Multiple channels can be described and cross flow is calculated based on user supplied input.

The computer code VIPRE was developed by Battelle Pacific Northwest Laboratories under the sponsorship of the Electric Power Research Institute (EPRI) and submitted to the NRC for generic review in 1984. The staff review was limited to pressurized water reactor applications and to heat transfer regimes up to the critical heat flux (CHF). The review included an audit calculation using the COBRA-IV code and the comparison of VIPRE results to experimental test data. The review consisted primarily of an evaluation of the internal program, including the governing conservation equations and constitutive equations, including the two-phase flow and heat transfer models and the numerical solution techniques. The staff required each VIPRE user to submit documentation describing the proposed use for the code, other computer codes with which it will interact, the source of each input variable, and the selected correlations, including justification for using the selected correlations. In particular it was required that any new CHF correlations that are to be used within VIPRE be evaluated against their experimental database to determine the appropriate departure from nucleate boiling ratio (DNBR) safety limit.

The NRC staff concluded that use of VIPRE as described in WCAP-14565 (Reference 11) is acceptable for licensing calculations and may be used to replace the THINC-IV and FACTRAN computer codes in Westinghouse refueling methodology provided that four conditions are met. These conditions, and the FENOC fulfillment of each, are listed in Section 4.1.17 of this Enclosure.

4.0 TECHNICAL ANALYSIS

The technical analysis conducted to support the proposed Technical Specification changes identified as EPU related are documented in Enclosure 2. Enclosure 2 includes the evaluation of initial condition uncertainties at EPU conditions, which are provided as input to the safety analyses; the development of any required changes to reactor trip or engineered safety feature actuation system setpoints; and changes to time constants, response times, tank volumes, DNB parameters, safety valve tolerances, etc. Enclosure 2 also documents the analyses performed to support the proposed changes to the Technical Specification Bases and the LRM that are a direct result of the EPU related changes.

A brief description of the technical analysis for the proposed Technical Specification changes is provided in the following paragraphs. These paragraphs do not address any changes that are considered administrative in nature.

4.1 Affected Technical Specification Systems, Components and Parameters

4.1.1 Rated Thermal Power

The revised TS definition of RTP states that RTP shall not exceed 2900 MWt, which will be the maximum steady state licensed power level following approval of the EPU. The new LRM definition, i.e. 1.0.1.a, links to the TS definition. The LRM also specifies an interim RTP value that is less than or equal to the maximum licensed power level. Although the maximum value of RTP will continue to be controlled by the TS following approval of the proposed TS change, a 10 CFR 50.36 assessment of the specification of an interim RTP value in the LRM is provided below.

Criterion 1: Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

Criterion 1 is not applicable because RTP is not installed instrumentation.

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

Criterion 2 is not applicable because an interim value of RTP lower than the maximum licensed power level is not a process variable or operating restriction that is relied upon as an initial condition of a design basis accident or transient analysis. The maximum licensed power level value of RTP is the process variable and operating restriction that is relied upon as an initial condition of a design basis accident or transient analysis. Since the maximum RTP value is a process variable that is an initial condition of a design basis accident or transient analysis, it will continue to be controlled by the TS following approval of the proposed change to its definition. However, specifying a conservative interim lower value of RTP in the LRM is not considered a process variable or operating restriction that is relied upon as an initial condition of a design basis accident or transient analysis, because the LRM interim value of RTP will always be less than or equal to the TS limit, i.e., the value used in the safety analysis. Maintaining the LRM RTP interim value less than or equal to the maximum TS RTP value assures that the plant is operated within its EPU safety analysis.

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

Criterion 3 is not applicable because RTP is not a structure, system or component.

Criterion 4: A structure, system, or component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

Criterion 4 is not applicable because RTP is not a structure, system or component.

Since the assessment of specifying an interim RTP value in the LRM shows that none of the criteria of 10 CFR 50.36(c)(2)(ii) are met, an interim RTP value can be specified outside of the TS in the LRM. The proposed change does not eliminate the existing RTP TS; it is merely modified to reference a lower interim value that is specified in the LRM. The BVPS TS will continue to have an RTP TS and it will limit the maximum power level to what was used in the EPU safety analysis. The inclusion of a definition for RTP in the LRM will permit operation at a power level less than or equal to the TS maximum value. Since the LRM interim value of RTP will be considered 100% RTP, the TS requirements that are specified as a percentage of RTP can be adjusted as necessary to maintain the same percentage of RTP. This will result in conservative operation of the BVPS units. Therefore, specifying lower interim RTP values in the LRM, while maintaining control over the maximum RTP value in the TS, complies with the requirements of 10 CFR 50.36.

4.1.2 Fuel Assemblies

As discussed in Section 4.3 of Enclosure 2, to demonstrate that the fuel assemblies will perform satisfactorily through their lifetime, the combined effects of the design basis loads were considered in evaluating the capability of fuel assemblies and their components to maintain structural integrity. The supporting studies documented in Enclosure 2, concluded that the V5H and RFA fuel assemblies are structurally and mechanically acceptable for the EPU conditions.

4.1.3 Refueling Water Storage Tank

As discussed in Section 9.5 of Enclosure 2, various applicable safety analyses were performed at a maximum refueling water storage tank temperature of 65°F or 105°F. However, the limiting maximum RWST temperature is limited to 65°F for both BVPS units for the EPU conditions due to the limiting case identified in the containment analyses documented in Reference 3.

4.1.4 Power Range, Neutron Flux High Negative Rate Trip

Reference 4 provides the methodology for the deletion of Power Range, Neutron Flux High Negative Rate trip. The trip was not credited for the EPU conditions because, as stated in Reference 5, no credit is taken for any direct reactor trip due to the dropped RCCA event or for automatic power reduction due to dropped RCCA(s). Application of the methodology described in Reference 4 ensures the DNB limits will not be exceeded during the course of a dropped RCCA event without a Power Range, Neutron Flux High Negative Rate trip. Section 5.3.4 of Enclosure 2 provides a discussion of the analysis of a dropped RCCA event for the BVPS units. The analysis results show that a dropped RCCA event does not adversely affect the core, with or without a reactor trip. The BVPS specific analyses required by Reference 5 will be incorporated into the Core Reload Safety Analysis prior to the return to power following the next refueling outage for each BVPS unit, which will precede the amendment implementation date requested by this submittal.

4.1.5 Overtemperature ΔT and Overpower ΔT (Unit 1 only)

The proposed Overtemperature ΔT and Overpower ΔT coefficient changes reflect the analyses documented in Sections 5.3 and 5.10, and are shown in Table 5.10-1 of Enclosure 2. Incorporation of these changes supports operation at the EPU conditions.

4.1.6 Pressurizer Safety Valves

As discussed in Section 5.3.6 of Enclosure 2, both the positive and negative valve setting tolerances for pressurizer safety valves were established to address the limits on DNBR and peak RCS pressure following a loss of external electrical load and/or turbine trip. The EPU analyses concluded that for the stated event, the valve setting tolerances do not result in a hazard to the integrity of the RCS. Therefore, the new positive valve setting tolerance is consistent with the analyses and acceptable for the EPU conditions.

4.1.7 Accumulators

The safety analyses in Sections 5.2.1 and 5.2.2 of Enclosure 2 provide the technical justification for the proposed change to the accumulator limits on water volume and nitrogen cover pressure. The revised nitrogen cover pressure and volume ensure sufficient accumulator volume injection under EPU conditions. Amendments 242 (Unit 1) and 125 (Unit 2) implemented the revised boron concentration limits for the accumulator and RWST. These limits ensure that the water supplied from the accumulators and RWST deliver sufficiently high boron concentration that, when mixed with other borated and non-borated water, the core will remain subcritical during the accident recovery recirculation phase for the EPU conditions.

4.1.8 Boron Injection Tank (Unit 1 only)

There are two Technical Specifications applicable to the boron injection tank (BIT). They are Technical Specification 3.5.4.1.1, "Boron Injection Tank ≥ 350°F" and Technical Specification 3.5.4.1.2, "Boron Injection Tank < 350°F". Technical Specification 3.5.4.1.1 specifies the volume and boron concentration requirements for the BIT to meet accident analysis assumptions in Modes 1 through 3. Technical Specification 3.5.4.1.2 imposes a requirement that the BIT flow path is isolated and the power is removed from the inlet and outlet valves whenever an RCS cold leg temperature is less than OPPS enable temperature. The applicability of TS 3.5.4.1.2 is less than or equal to the enable temperature of TS 3.4.9.3, namely the OPPS enable temperature of 343°F. The plant is in Mode 4 when the average RCS temperature is less than 350°F.

4.1.8.1 Technical Specification 3.5.4.1.1, "Boron Injection Tank ≥ 350°F".

The analyses conducted to support the EPU do not credit the BVPS Unit 1 BIT as a source of borated water for accident mitigation. Therefore Technical Specification 3.5.4.1.1 can be deleted from the BVPS Unit 1 Technical Specifications. With this change, the Unit 1 accident analysis is consistent with the Unit 2 accident analysis. The BIT for Unit 2 has never been connected, thus Unit 2 never had a BIT boron concentration requirement.

Without an analysis requirement that the BIT is a source of borated water for accident mitigation, none of the four criteria of 10 CFR 50.36(c)(2)(ii) are applicable and thus, Technical Specification 3.5.4.1.1 can be deleted. The following is an assessment of the removal of TS 3.5.4.1.1 against the criteria.

It is stated in 10 CFR 50.36 that a Technical Specification limiting condition for operation of a nuclear reactor must be established for each item meeting one or more of the following four Criteria.

Criterion 1: Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

Criterion 1 is not applicable because there is no BIT boron concentration associated installed instrumentation that is applicable to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

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

Criterion 2 is not applicable because there is no BIT boron concentration associated process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. The EPU analysis does not credit the BIT as a source of borated water for accident mitigation. The EPU fuel design margins do not credit the BIT as a source of negative reactivity. Thus, deleting TS 3.5.4.1.1

does not remove a design feature that is an initial condition of a design basis accident or transient analysis.

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

Criterion 3 is not applicable. This change does not affect any structure, system or components in the high head safety injection flow path. Design basis accidents are successfully mitigated without crediting the BIT as a source of boric acid.

Criterion 4: A structure, system, or component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

Criterion 4 is not applicable because operating experience and a probabilistic risk assessment has not shown the absence of a BIT boron concentration requirement to a significant risk to public health and safety. This conclusion is based on industry experience at other Westinghouse plants of similar design without a BIT boron concentration requirement, and the experience accumulated at BVPS Unit 2.

<u>4.1.8.2 Technical Specification 3.5.4.1.2, "Boron Injection Tank < 350°F".</u>

The purpose of TS 3.5.4.1.2 is to prevent a potential overpressurization due to an inadvertent safety injection signal when the RCS temperature is below the OPPS enable temperature. This is achieved by isolating the BIT flow path when RCS temperature is below the OPPS enable temperature. The creation of TS 3.5.4, "HHSI FLOW PATH", retains all of the requirements of TS 3.5.4.1.2 except for the mention of the BIT in the flow path. As the BIT is no longer credited as a source of boron for shutdown margin, it need only to be considered as part of the flow path. As such, its mention in the flow path is inconsequential from an accident mitigation aspect.

The Applicability of TS 3.5.4 matches the Applicability of TS 3.4.9.3, since the flow path is to be isolated whenever the RCS temperature is below the OPPS enable temperature. The flow path is required to be isolated by the TS and the TS Bases describes an acceptable method of isolating the flow path. The TS is also being made slightly more restrictive because a requirement to isolate the flow path in one hour is being added to the ACTION statement. Presently there is no time associated with the ACTION statement.

The addition of Note (2) to TS 3.5.2 is being made to permit an orderly transition into and out of the Applicability of TS 3.5.4. The addition of Note (2) provides the same transitioning flexibility as Note (1), which pertains to charging pump injection capability. The addition of Note (2) assures that flow path isolation is maintained throughout the Applicability of TS 3.5.4 and that the assumptions of the OPPS analysis is maintained for a limited time when in the Applicability of TS 3.5.2, i. e. Mode 3. This is acceptable in Mode 3 due to the limited time, provided by the proposed note that the flow path can be isolated when the plant is in Mode 3.

The modification to Surveillance Requirement 4.5.3.1 is being made to eliminate the requirements that are not necessary in Mode 4. Automatic alignment of the flow path following a safety injection signal is not required until the plant enters the Applicability of TS 3.5.2, i.e., Mode 3. In Mode 4 only manual actuation of safety injection is required. In addition, only one train of ECCS is required by TS 3.5.3, i.e., Mode 4. Therefore the Surveillance Requirements pertaining to electrical power alignment, valve alignments and pump starts following a safety injection signal, are not applicable for TS 3.5.3, i.e., Mode 4. The proposed change to Surveillance Requirement 4.5.3.1 is also consistent with the requirements of the Standard Technical Specifications (STS) (Reference 10).

4.1.9 Main Steam Safety Valves

The loss of load/turbine trip safety analysis in Section 5.3.6 of Enclosure 2 demonstrates, that for EPU conditions, the transient response for turbine trip occurring from full power without a direct reactor trip presents no hazard to the integrity of the RCS or the main steam system. One turbine trip analysis is performed assuming primary system pressure control via operation of the pressurizer relief valves and spray. This analysis demonstrates that the DNB design basis will continue to be met following the EPU. Another analysis was performed assuming no primary system pressure control, but crediting reactor trip on high pressurizer pressure and operation of the pressurizer safety valves. This analysis demonstrates that RCS integrity will continue to be maintained by demonstration that the maximum RCS pressure does not exceed 110% of the design pressure. All cases analyzed demonstrate that the MSSVs with a lift setting tolerance of ± 3% maintain main steam system integrity by limiting the maximum steam pressure to less than 110% of design pressure.

The small break LOCA safety analysis in Sections 5.2.2 and 9.10.1 of Enclosure 2 credits a MSSV lift setting tolerance of +1%/-3% for the MSSV with the lowest setting pressure. Thus, although the loss of load/turbine trip safety analysis of Section 5.3.6 of Enclosure 2 demonstrates that the MSSVs are acceptable for EPU conditions with a lift setting tolerance of ± 3%, the MSSV with the lowest setting pressure is limited to a lift setting tolerance of +1%/-3% due to the small break LOCA safety analysis. The conclusions of these analyses are discussed in Section 9.10.1 of Enclosure 2.

4.1.10 Primary Plant Demineralized Water Storage Tank

Section 3.1.4.4 of Enclosure 2 provides a discussion of the effects of the EPU on the primary plant demineralized water storage tank. The proposed changes will ensure that the tank meets its design basis of providing sufficient volume for 9 hours at hot standby (hot zero power) conditions following a loss of offsite power for the EPU conditions. The minimum usable volume specified in Technical Specification 3.7.1.3 is the available usable volume to remove decay heat and restore steam generator levels. The minimum usable volume conservatively bounds the analysis values for both BVPS units.

4.1.11 Unit 1 Replacement Steam Generator Setpoints

4.1.11.1 Steam Generator Water Level – Low-Low

As discussed in Section 5.10 of Enclosure 2, the steam generator water level low-low setpoint and allowable value were revised for the Unit 1 RSGs, which incorporate a larger narrow range span and a different nominal indicated water level than the Unit 1 OSGs. The revised setpoint and allowable value were calculated for the EPU power level of 2900 MWt and incorporate the recommendations provided in Westinghouse NSAL-03-9 (Reference 13).

As discussed in Section 5 of Enclosure 2, applicable safety analyses were performed incorporating the Unit 1 RSG design and using the applicable safety analysis limits for the low-low water level reactor trip setpoint and auxiliary feedwater actuation. The applicable safety analyses show that acceptance criteria are satisfied. Operability margin to trip analyses, as discussed in Section 3.2.1 of Enclosure 2, shows that operability margin to the low-low water level trip setpoint is acceptable for the Unit 1 RSG. The analyses in Enclosure 2 demonstrate that the implementation of the Unit 1 RSGs, and the incorporation of the associated low-low water level setpoint and allowable value, support operation of BVPS Unit 1 at the EPU power level of 2900 MWt. These analyses performed for the EPU power level of 2900 MWt bound and support operation at the pre-EPU power level of 2689 MWt.

4.1.11.2 Steam Generator Water Level – High-High

As discussed in Section 5.10 of Enclosure 2, the steam generator water level high-high setpoint and allowable value were revised for the Unit 1 RSGs, which incorporate a larger narrow range span and a different nominal indicated water level than the Unit 1 OSGs. The revised setpoint and allowable value were calculated for the EPU power level of 2900 MWt and incorporate the recommendations provided in Westinghouse NSAL-03-9 (Reference 13).

As discussed in Section 5 of Enclosure 2, applicable safety analyses were performed incorporating the Unit 1 RSG design and using the applicable safety analysis limits for the high-high water level for reactor trip setpoint and auxiliary feedwater actuation. The applicable safety analyses show that acceptance criteria were satisfied. Operability margin to trip analyses, as discussed in Section 3.2.1 of Enclosure 2, shows that operability margin to the high-high water level turbine trip and feedwater isolation actuation setpoint is acceptable for the Unit 1 RSG. The analyses in Enclosure 2 demonstrate that the implementation of the Unit 1 RSGs and the incorporation of the associated high-high water level setpoint and allowable value support operation of BVPS Unit 1 at the EPU power level of 2900 MWt. These analyses performed for the EPU power level of 2900 MWt bound and support operation at the pre-EPU power level of 2689 MWt.

4.1.11.3 Steam Generator Level

The steam generator water level value used to verify steam generator operability in Modes 4 and 5 was revised for the Unit 1 RSGs, which incorporate a larger narrow range span and a different nominal indicated water level than the Unit 1 OSGs. The revised value was calculated for the Unit 1 RSG design to satisfy the functional requirement to have the water level cover the top of the tube bundle so that the U-tubes are completely submerged. Keeping the water level above the top of the tube bundle promotes the capability of the steam generators to function as a heat sink to remove decay heat in Modes 4 and 5 under either forced circulation or natural circulation conditions. As discussed in Section 5.9 of Enclosure 2, natural circulation capability was confirmed for the EPU power level of 2900 MWt. The confirmation of natural circulation capability for the EPU power level of 2900 MWt bound and support operation at the pre-EPU power level of 2689 MWt.

4.1.12 Steam Generators

Section 4.7.1 of Enclosure 2 provides a brief description of the Unit 1 RSG design, including design and analysis provisions in the areas of thermal-hydraulic performance, structural integrity, U-bend fatigue, tube wear, tube plugging limit, and tube degradation. The Unit 1 RSGs have been designed and analyzed for operation at the EPU power level of 2900 MWt, which bounds and supports operation at the pre-EPU power level of 2689 MWt. The analysis was performed consistent with the guidance in Draft Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes (For Comment)," August 1976 (Reference 14) to justify the Technical Specification tube plugging limit of 40%. This steam generator model has been in service at the Farley Nuclear Plant since the spring of 2000.

Section 4.7.2 of Enclosure 2 provides a brief description of the Unit 2 original steam generator design, including design and analysis provisions in the areas of thermal-hydraulic performance, structural integrity, U-bend fatigue, tube wear, tube plugging limit, and tube degradation. The Unit 2 steam generators have been analyzed for operation at the EPU power level of 2900 MWt, which bounds and supports operation at the pre-EPU power level of 2689 MWt.

4.1.13 Seal Injection Flow

The proposed change to the seal injection TS will affect only the charging pump discharge pressure requirement. The change will raise the minimum charging pump discharge pressure required when establishing reactor coolant pump (RCP) seal injection flow. The purpose of the change is to increase the analytical resistance used for the seal injection flow path. The change will result in improved safety injection flow for the small break LOCA analysis since it will increase the safety injection flow directed to the RCS via the safety injection points. The seal injection line is not isolated during a safety injection actuation and the flow to the RCP seals is not credited in the small break LOCA analyses.

4.1.14 Reactor Coolant System Specific Activity (Unit 1 only)

The reactor coolant system specific activity is limited in order to maintain the offsite and the control room operator doses within the applicable regulatory limits for a postulated MSLB or a postulated SGTR, both of which have the potential to release a significant amount of reactor coolant activity to the environment. The proposed change will increase the reactor coolant iodine specific activity limit from 0.1 μCi/gm Dose Equivalent I-131 to 0.35 μCi/gm Dose Equivalent I-131. This impacts both the pre-accident iodine spike case, which assumes an initial reactor coolant iodine specific activity 60 times the Technical Specification limit, as well as the concurrent iodine spike case, which assumes that immediately following the accident the iodine appearance rate increases to 500 times (for MSLB) or 335 times (for SGTR) the equilibrium appearance rate corresponding to the Technical Specification iodine specific activity. The radiological consequence analyses for a MSLB and a SGTR are described in Sections 5.11.9.7 and 5.11.9.8 of Enclosure 2, respectively. The resultant offsite doses and control room operator doses are within the regulatory limits of 10 CFR 50.67 and Regulatory Guide 1.183.

4.1.15 Secondary Coolant System Specific Activity (Unit 1 only)

The secondary coolant system specific activity is limited to ensure that the offsite doses and the control room operator dose due to steam releases from a postulated accident, in conjunction with other releases resulting from the accident, will be within the regulatory limits. The critical accident that governs the secondary coolant specific activity is the MSLB, which assumes a complete dryout of the faulted steam generator, releasing all secondary system iodine activity at the Technical Specification limit to the environment. The proposed change will increase the secondary coolant specific activity from 0.05 μCi/gm Dose Equivalent I-131 to 0.1 μCi/gm Dose Equivalent I-131. The radiological consequence analysis for a MSLB is described in Section 5.11.9.7 of Enclosure 2. The resultant offsite doses and control room operator doses are within the regulatory limits of 10 CFR 50.67 and Regulatory Guide 1.183.

4.1.16 Welded Steam Generator Sleeves (Unit 2 only)

WCAP-13483, Revision 1 is referenced in Technical Specification 3.4.5, "Steam Generators" for BVPS Unit 2 as the basis for the acceptability of Westinghouse laser welded sleeves. Since the EPU conditions cause changes in the fluid conditions in the steam generators, which result in changes to the stress state of the steam generator repairs such as laser welded sleeves, WCAP-13483 has been revised to address EPU conditions. The analyses addressed in WCAP-13483, Revision 2 (Reference 9) includes a stress intensity evaluation, a primary side secondary stress range evaluation, and a fatigue evaluation for mechanical and thermal conditions. Calculations are also performed to establish minimum wall requirements for the sleeve and a corresponding plugging limit for the sleeve. Based on the results of these analyses, the design of the laser welded tubesheet sleeve and the tube support plate sleeve are concluded to meet the requirements of the ASME Code.

In addition to addressing the fluid conditions and resultant stress state of the laser welded sleeves due to the EPU, topics requiring discussion or involving new features that have occurred in the laser welded process since Revision 1 of WCAP-13483 was issued are included in Revision 2. These topics include weld width clarification and addition of elevated tubesheet sleeves.

Sections 4.7.2.4.6 and 4.7.2.4.7 of Enclosure 2 describe the analysis and evaluation performed to determine an adequate repair limit for both laser and TIG welded steam generator tube sleeves for the EPU conditions. The repair limit is defined as the depth of degradation at or beyond which the tube shall be repaired or removed from service by plugging. The repair limit assumes a tube wall combined allowance for postulated degradation growth and eddy current uncertainty of 20% through-wall per cycle to establish the TS repair limits for the sleeves.

The Westinghouse letter reference added to the Bases of TS 3.4.5 documents the evaluation performed to confirm the continued validity of the Combustion Engineering reports referenced in Surveillance Requirement 4.4.5.4.a.9 and Section 4.7.2.4.7 of Enclosure 2. The Westinghouse and ABB Combustion Engineering reports presently referenced in TS 3.4.5 remain valid for EPU conditions except that the repair limit for TIG welded steam generator sleeve requires a reduction. The repair limit adjustment is discussed further below.

The analysis performed in support of the EPU indicated that it would be necessary to remove tubes with TIG welded steam generator sleeves from service upon discovering an imperfection depth at or beyond the new TIG welded steam generator sleeve repair limit. This action would support the structural integrity of the tubes that may have to be sleeved under the EPU conditions and would preclude the failure of a TIG welded sleeve under EPU conditions.

4.1.17 VIPRE

FENOC intends to use the VIPRE code at BVPS for DNB analysis for those UFSAR transients and accidents for which DNB might be of concern. Typically these events include:

- steam line break (Section 5.3.12 of Enclosure 2),
- rod withdrawal from subcritical or at power (Sections 5.3.2 and 5.3.3 of Enclosure 2),
- loss of forced reactor coolant flow (Sections 5.3.13 and 5.3.14 of Enclosure 2),
- locked reactor coolant pump rotor or shaft break (Section 5.3.15 of Enclosure 2),
- dropped rod/bank (Section 5.3.4 on Enclosure 2),
- startup of an inactive reactor coolant pump (Section 5.3.1 of Enclosure 2), and
- a feedwater malfunction (Section 5.3.9 on Enclosure 2).

These events, excluding startup of an inactive reactor coolant pump, are presently analyzed using the LOFTRAN, THINC-IV or FACTRAN codes, all of which have been approved by the NRC staff. The THINC-IV code performs thermal/hydraulic calculations within the fuel channels, including departure from nucleate boiling ratio (DNBR) evaluation at the fuel pin surface. For calculations in which transient heat conduction within the fuel pins is important, this calculation is performed by FACTRAN, which describes the conductive heat transfer within the fuel pin interior and the convective heat transfer at the surface. Iteration may be required between the two codes. Both the thermal/hydraulic and the conduction/convection calculations are performed simultaneously in VIPRE. In addition to the transients listed above, VIPRE can be used for calculations of the core limits which can be used for reactor setpoint analysis such as Overtemperature ΔT trip protection.

Inputs to VIPRE that describe the radial and axial power shapes, engineered hot channel factors for enthalpy rise and heat flux are specific to the reactor core being analyzed. These BVPS specific inputs are provided in Section

5.3 of Enclosure 2. In using the THINC-IV code, the BVPS analysis applies a 5% reduction factor to the flow entering the hot channel. This reduction factor for core analyses will continue to be used when using VIPRE.

The NRC Safety Evaluation Report dated January 19, 1999 (Reference 15) states that a utility's use of VIPRE, as described in WCAP-14565-P-A (Reference 11) may be approved by the NRC staff, and may be used to replace the THINC-IV and FACTRAN computer codes in Westinghouse refueling methodology, provided the following conditions are met. These four conditions were appropriately considered in the safety evaluation documented in Enclosure 2. Each of the four conditions, and their fulfillment, is addressed below.

Condition 1. Selection of the appropriate critical heat flux (CHF) correlation, DNBR limit, engineered hot channel factors for enthalpy rise and other fuel-dependent parameters for a specific plant application should be justified with each submittal.

This condition is met. Section 5.3 of Enclosure 2 provides the appropriate CHF correlation, DNBR limit, engineered hot channel factors for enthalpy rise and other fuel-dependent parameters used in the BVPS EPU analysis.

Condition 2. Reactor core boundary conditions determined using other computer codes are generally input into VIPRE for reactor transient analysis. These inputs include core inlet coolant flow and enthalpy, core average power, powershape and nuclear peaking factors. These inputs should be justified as conservative for each use of VIPRE.

This condition is met. Section 5.3 of Enclosure 2 provides the appropriate reactor core boundary conditions determined using other computer codes that were input into VIPRE for the reactor transient analysis. These conservative inputs include the core inlet coolant flow and enthalpy, core average power, powershape and nuclear peaking factors used in the BVPS EPU analysis.

Condition 3 The NRC staff generic safety evaluation report for VIPRE set requirements for use of new CHF correlations with VIPRE. These requirements should be justified for each use of VIPRE. Use of other CHF correlations not currently included in VIPRE will require additional justification.

This condition is met. BVPS has met these requirements for using the WRB-1 and WRB-2M correlations because the BVPS DNBR limit is maintained ≥ 1.17 for WRB-1 and ≥ 1.14 for WRB-2M, as shown in the proposed change to TS 2.1.1.1. The BVPS application of VIPRE does not include any other CHF correlations.

Condition 4 The NRC staff's generic review of VIPRE did not extend to post CHF calculations. VIPRE does not model the time-dependent physical changes that may occur within the fuel rods at elevated temperatures. The NRC staff requires that appropriate justification be submitted with each usage of VIPRE in the post-CHF region to ensure that conservative results are obtained.

This condition is not applicable. This condition involves the use of VIPRE beyond CHF heat transfer conditions. The BVPS EPU application of VIPRE does not use VIPRE for such conditions.

4.2 Radiological Analyses

Section 5.11 of Enclosure 2 documents the radiological analyses conducted to support the EPU conditions. The revised radiological analyses utilize a full implementation of the AST methodology and control room dispersion atmospheric factors based on ARCON96 methodology. The AST methodology was previously used in the fuel handling accident (Amendment 241/121, Reference 16) and the loss-of-coolant and control rod ejection accidents (Amendment 257/139, Reference 17) for both BVPS units.

The evaluation of the post accident radiological consequences of the EPU demonstrate that offsite and control room doses associated with accidents will be within the acceptance criteria of 10 CFR 50.67 as supplemented by Regulatory Guide 1.183 (Reference 1).

A detailed description of these analyses and station evaluations conducted in support of the requested changes is provided in Enclosure 2. The impact of the proposed changes on other safety analyses and plant systems has also been evaluated and demonstrates acceptable performance.

The proposed changes to the Technical Specifications allowing operation of both units at the EPU power level are based on the revised analyses and supporting evaluations documented in Section 5.11 of Enclosure 2. These analyses and evaluations demonstrate the safe operation of the BVPS units at the EPU conditions.

4.3 Related Plant Modifications

Section 1.1.2 of Enclosure 2 provides a list of the principal plant modifications that will be made to support the EPU.

5.0 REGULATORY SAFETY ANALYSIS

The proposed amendments support an Extended Power Uprate (EPU) for Beaver Valley Power Station (BVPS) Unit Nos. 1 and 2. Throughout this submittal all cited power levels are in Rated Thermal Power (RTP), unless otherwise noted. The amendments will revise the BVPS Unit 1 Operating License to permit operating at 2900 MWt with the replacement steam generators (Model 54F) installed. The proposed changes will revise the BVPS Unit 2 Operating License to permit operating at 2900 MWt using the original steam generators (Model 51M).

Approval of this License Amendment Request (LAR) will change the BVPS licensing and design basis to include power operation at 2900 MWt. However, the actual escalation to the EPU power level of 2900 MWt may occur in stages. The staged approach is due to the fact that certain balance of plant (BOP) modifications may not be completed by the requested amendment implementation date. With the approval of the new accident, radiological, and containment analyses, the BVPS units will be approved to operate at 2900 MWt. However, although all safety related modifications will be completed prior to amendment implementation, without certain BOP modifications the megawatts electric (MWe) output will be limited to the existing value. Since the supporting EPU analyses bound operation at the pre-EPU level of 2689 MWt, it is acceptable to continue operation at the pre-EPU level until the necessary BOP modifications have been completed. Reactor power may be raised in stages as the necessary BOP modifications are completed. Following NRC approval of plant operations at 2900 MWt, the actual value of Rated Thermal Power (RTP) will be controlled by the proposed changes to the Technical Specifications, the Licensing Requirements Manual and the BVPS 10 CFR 50.59 process.

The requested amendments include changes that are required to support the EPU and other changes that are being made to enhance the existing BVPS Technical Specifications, including changes that are considered as administrative.

The EPU related Technical Specification (TS) changes requested include:

(a) increasing the Maximum Power Level specified in each unit's license;

(b) revising the value and definition of Rated Thermal Power (RTP);

(c) revising fuel assembly specific departure from nucleate boiling ratios and correlations;

(d) raising the maximum temperature of the refueling water storage tank;

(e) modifying Overtemperature ΔT and Overpower ΔT equations for BVPS Unit 1 only;

(f) revising the steam generator water level low-low and high-high setpoints for BVPS Unit 1 only;

(g) revising the required steam generator secondary side level in Modes 4 and 5 for BVPS Unit 1 only;

(h) raising the tolerance settings for the pressurizer safety valves;

(i) revising the steam generator Technical Specification to reflect the replacement steam generators for BVPS Unit 1 only;

(j) revising steam generator Technical Specification tube sleeve reference and the TIG welded steam generator sleeve repair limit for BVPS Unit 2 only;

(k) revising the specific activity of the primary coolant system for BVPS Unit 1 only;

(l) increasing the band for accumulator water volume and nitrogen pressure;

(m) revising the required charging pump discharge pressure for reactor coolant pump seal injection flow;

(n) revising the tolerance settings for the main steam safety valves;

(o) changing the allowable power limits associated with inoperable main steam safety valves;

(p) revising the primary plant demineralized water storage tank volume;

(q) revising the specific activity of the secondary coolant system for BVPS Unit 1 only; and

(r) adding WCAP-14565 and WCAP-15025 to the list of NRC approved methodologies in Technical Specification 6.9.5.

A change to the BVPS licensing basis that is not directly reflected in the Technical Specifications, but is consistent with EPU analysis and requires NRC approval, is full implementation of the Alternative Source Term methodology of Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors."

The Technical Specification changes requested that are not directly related to the EPU include:

(a) deletion of the Power Range, Neutron Flux High Negative Rate trip;

(b) addition of a footnote to Table 3.3-3, Engineered Safety Features Actuation System Instrumentation, concerning time constants for steamline pressure low for BVPS Unit 1 only;

(c) removal of the boron injection tank boron concentration Technical Specification for BVPS Unit 1 only; and

(d) renaming the boron injection tank flow path Technical Specification for BVPS Unit 1 only.

The administrative Technical Specification changes requested include:

(a) removal of the amendment number from the operating license for each unit; and

(b) correction of an inconsistency regarding a referenced permissive for BVPS Unit 1 only.

The proposed EPU Technical Specification changes also result in modifications to the Technical Specification Bases and Licensing Requirements Manual (LRM). These modifications are related to the revised analysis at the EPU conditions, including full implementation of the Alternative Source Terms (AST) methodology, and the necessary proposed changes to the Technical Specifications. The proposed Technical Specification Bases and LRM changes are provided for completeness and information only. They are summarized below, but are not discussed further.

(a) adding a definition of RATED THERMAL POWER to the LRM;

(b) revising response times and time constants for various reactor trip system instrumentation;

(c) revising various departure from nucleate boiling parameters;

(d) changing the reference power levels in the leading edge flow meter licensing requirement;

(e) modifying the reactor core safety limit figure;

(f) adding a reference to Westinghouse letter FENOC-02-304 to the Bases of TS 3.4.5;

(g) revising the TS Bases for TS 3.7.1.2, Auxiliary Feedwater System, and TS 3.7.7, Control Room Habitability System;

(h) revising the Effective Full Power Years for the reactor coolant system heatup and cooldown curves for Unit 1 only; and

(i) revising the TS Bases and LRM to reflect the full implementation of the AST methodology.

5.1 No Significant Hazards Consideration

FirstEnergy Nuclear Operating Company (FENOC) has evaluated whether or not a significant hazards consideration is involved with the proposed amendments by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment", as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No. The proposed changes will not involve a significant increase in the probability or consequences of an accident previously evaluated.

<u>EPU Related Changes</u>

A comprehensive analytical effort has been performed to incorporate the proposed changes into the design and analysis basis for Beaver Valley Power Station (BVPS) Units Nos. 1 and 2. Analyses and evaluations have been performed for the nuclear steam supply systems (NSSS) and balance of plant (BOP) systems and components, including the nuclear fuel. Safety and dose consequence analyses have been updated. These comprehensive analytical efforts demonstrate that BVPS Units Nos. 1 and 2 meet applicable design and licensing requirements. These analytical efforts addressed the proposed changes as applicable, including changes to maximum rated thermal power (RTP), reactor core safety limits, refueling water storage tank temperature, Reactor Trip System (RTS) and Engineered

Safety Feature Actuation System (ESFAS) setpoints, reactor coolant system and main steam safety valves lift setting tolerance, steam generator sleeve repair limits, reactor and secondary coolant activity limits, accumulator volumes and pressures, boron injection tank, seal injection flow, and primary plant demineralized water storage tank volume.

The safety and radiological dose consequence analyses confirmed that safety analysis and dose consequence analysis acceptance criteria will be satisfied under the Extended Power Uprate (EPU) conditions, including changes to RTP, reactor core safety limits, RTS and ESFAS setpoints, reactor and secondary coolant activities, and other safety analysis inputs related to the proposed changes.

The reviews for NSSS and BOP systems and components confirmed that they will function as designed and applicable performance requirements will be satisfied. As an example, the reactor coolant system and main steam safety valves will provide overpressure protection for the reactor coolant system and main steam system, respectively, at the EPU RTP of 2900 MWt with the changes to valve lift setting tolerances. Likewise, the change to the BVPS Unit 2 TIG welded steam generator sleeve repair limit will maintain the structural integrity of the sleeve under EPU conditions, thus precluding the failure of a TIG welded steam generator sleeve.

None of the proposed changes are initiators of any design basis accident or event, and therefore, will not increase the probability of any accident previously evaluated. The probability of any evaluated accident or event is independent of the changes being proposed. The proposed changes will not adversely affect accident initiators or precursors. They will not alter or prevent the ability of structures, systems or components from performing their intended function within the applicable acceptance limits.

<u>Unit 1 Replacement Steam Generators</u>

For the purpose of this evaluation, the proposed changes to the Technical Specification for the Unit 1 replacement steam generators (RSG) can be grouped into the following areas:

(a) The first area of change is to remove the references to repair of tubes by sleeving since they are not applicable to the RSG tubes.

The accidents of interest are tube rupture and steam line break. A reduction in tube integrity could increase the possibility of a tube rupture accident and increase the consequences of a steam line break. The tubing in the RSGs is designed and evaluated consistent with the margins of safety specified in the ASME Code, Section III. The program for periodic inservice inspection provides sufficient time to take proper and timely corrective action if tube degradation is present. The ASME Section XI basis for the 40% through wall plugging limit is applicable to the RSGs just as it was to the original steam generators (OSG). An analysis has been performed consistent with the guidance in Draft Regulatory Guide 1.121 to justify the applicability of the 40% through wall plugging limit. As a result, there is no reduction in tube integrity for the replacement steam generators.

Since the Unit 1 Technical Specification primary-to-secondary leakage limit is more restrictive than the limit originally licensed and agrees with the current guidance of EPRI Technical Report No. 1003138, Revision 6, "PWR SG Examination Guidelines," October 2002, and NEI 97-06, Revision 1, "Steam Generator Program Guidelines," January 2001, it provides additional assurance that the integrity of steam generator tubes will be maintained during subsequent operation.

Elimination of the repair option and the associated references to repair of the OSG tubes is an administrative adjustment since the sleeve design is not applicable to the RSGs. The elimination of the repair option does not alter the requirements for inservice inspection or reduce the plugging limit for the tubes.

(b) The second area of change is to remove the references to voltage-based repair criteria on tube-to-tube support plate intersections since they are not applicable to the RSG tubes.

Elimination of the repair option and the associated references to repair of the OSG tubes is an administrative adjustment since the voltage based repair criteria is not applicable to the RSGs. The elimination of the repair option does not alter the requirements for inservice inspection or reduce the plugging limit for the tubes.

(c) The third area of change is to update the wording and content of the Technical Specification to provide clarification and to incorporate wording enhancements consistent with the updates made to the subject Technical Specification for several other plants that have replaced steam generators. An update in this area includes the addition of a "Note" to exempt the replacement steam generators from inservice inspection requirements during the steam generator replacement outage. Since the RSG will be subjected to a preservice inspection prior to installation, there is no need to perform inservice inspection following installation.

The changes to update the wording and content of the Technical Specification to provide clarification and to incorporate wording enhancements are administrative changes that provide clarifications. These changes do not alter the requirements for inservice inspection or the plugging limit for the tubes.

(d) The fourth area of change is to revise the steam generator water levels.

The proposed steam generator water level setpoint changes do not impact the initiation of accidents; therefore, they do not involve an increase in the probability of an accident previously evaluated. The proposed changes do impact the safety analyses for accidents that credit the applicable trips and associated system actions, however, they do not alter these accidents or the associated accident acceptance criteria. The safety analyses for these accidents have been performed at the EPU power level and show acceptable results. Therefore, the proposed changes do not involve a significant increase in the consequences of an accident previously evaluated.

The proposed change to steam generator water level used to verify steam generator operability in Modes 4 and 5 does not impact the initiation of accidents; therefore, it does not involve an increase in the probability of an accident previously evaluated. The proposed change does not alter the safety analyses for accidents or the associated accident acceptance criteria. Therefore, the proposed change does not involve a significant increase in the consequences of an accident previously evaluated.

The proposed changes, due to the replacement steam generators, do not alter the requirements for tube inspection, tube integrity, or tube plugging limit; therefore, they do not involve a significant increase in the probability or consequences of an accident previously evaluated.

Non-EPU Related Changes

In the EPU analysis, no credit is taken for any direct reactor trip due to the dropped rod cluster control assembly (RCCA) event or for automatic power reduction due to dropped RCCA(s). The proposed deletion of the Power Range, Neutron Flux High Negative Rate Trip will not increase the probability or consequences of an accident, namely the dropped RCCA event. The event will not adversely affect the core since the departure from nucleate boiling ratio (DNBR) will remain above its limit, with or without the subject trip.

Deletion of the Boron Injection Tank (BIT) boron concentration Technical Specification will not involve a significant increase in the probability or consequences of an accident previously evaluated because BIT boron concentration is not an accident initiator and the BIT as a source of boron was not credited in the EPU analysis. The modification to the BIT flow path Technical Specification will not involve a significant increase in the probability or consequences of an accident previously evaluated because the flow path isolation requirements are retained.

Use of the VIPRE computer code at BVPS for departure from nucleate boiling (DNB) analysis for those Updated Final Safety Analysis Report (UFSAR) transients and accidents for which DNB might be a concern will not involve a significant increase in the probability or consequences of an accident previously evaluated for the following reasons. The code is an evaluation tool that is independent of the probability of an accident. Use of the code establishes DNB limits such that core damage will not occur. Thus, use of the code will not involve a significant increase in the consequences of an accident previously.

Radiological Changes

The EPU radiological analysis reflects a full application of the AST methodology and incorporation of the ARCON96 methodology for on-site atmospheric dispersion factors. The EPU radiological analysis concludes that normal operation of the BVPS units under the EPU conditions with atmospheric containments will not impact either unit's compliance with the normal operation operator exposure limits set forth in 10 CFR 20, or the public exposure limits set forth in 10 CFR 20, 10 CFR 50, Appendix I and 40 CFR 190, or with the post-accident exposure limits set forth by 10 CFR 50.67, as supplemented by Regulatory Guide 1.183, for the plant operator and the public.

The effects on accident radiation dose for the EPU considered the replacement of the Unit 1 steam generators, raising the core power level to 2900 MWt, incorporation of the ARCON96 methodology and the full implementation of the AST methodology. None of these changes are initiators of any design basis accident or event, and therefore, will not increase the probability of any accident previously evaluated. The probability of any evaluated accident or event is independent of these changes.

These proposed changes required alteration of some assumptions previously made in the radiological consequence evaluations. The assumption alterations were necessary to reflect the new steam generators for Unit 1, the increased core power level, and the incorporation of the ARCON96 and AST methodologies. These changes were evaluated for their affect on accident dose consequences. The updated dose consequence analyses demonstrate compliance with the limits set forth for AST applications in 10 CFR 50.67, as supplemented by Regulatory Guide 1.183.

Therefore, in conclusion, none of the proposed changes involve a significant increase in the probability of an accident previously evaluated, and the dose consequences remain within the allowable limits set forth for AST applications in 10CFR50.67, as supplemented by Regulatory Guide 1.183.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No. The proposed change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

EPU Related Changes

No new accident scenarios, failure mechanisms or single failures are introduced as a result of the proposed changes. All systems, structures and components previously required for the mitigation of an event remain capable of fulfilling their intended design function. The proposed changes will not have an adverse effect on any safety-related system or component, and will not challenge the performance or integrity of any safety related system. The Unit 2 steam generator TIG welded sleeves repair limit does not create the possibility of a new or different kind of accident from any accident previously evaluated because it does not result in the Unit 2 steam generator being operated in a different manner and it ensures that the structural integrity of tubes that are sleeved is maintained, thus precluding failure of a sleeve under EPU conditions.

Unit 1 Replacement Steam Generators

The areas of changes described previously for the Unit 1 RSGs do not affect the design or function of any other safety-related component. With respect to postulated accident conditions, the OSGs and the RSGs are the same. There is no mechanism to create a new or different kind of accident for the RSGs by eliminating repair criteria or by clarifying the applicability of inservice inspection requirements because a baseline of tube conditions is established and plugging limits are maintained to ensure that defective tubes are removed from service.

The proposed changes to steam generator water level setpoints, and the steam generator water level used to verify steam generator operability in Modes 4 and 5 do not impact the initiation of accidents. They do not alter the accidents that credit the associated trips or accident acceptance criteria. Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

The proposed changes do not alter the requirements for tube inspection, tube integrity, or tube plugging limit; therefore, they do not create the possibility of a new or different kind of accident from any previously evaluated.

Non-EPU Related Changes

The proposed deletion of the Power Range, Neutron Flux High Negative Rate Trip will not result in a new or different kind of accident because no new or different kind of accidents are created by its deletion. The trip was the only one assumed for the dropped RCCA event. The supporting analysis demonstrates that neither the trip, nor a power reduction, is needed to accommodate a dropped RCCA event. Thus, deletion of the trip will not create a new or different kind of accident.

Deletion of the Boron Injection Tank (BIT) boron concentration Technical Specification will not create the possibility of a new or different kind of accident from any accident previously evaluated because the BIT as a source of boron was not credited in the EPU analysis. The modification to the BIT flow path Technical Specification will not create the possibility of a new or different kind of accident from any accident previously evaluated because the flow path isolation requirements are retained.

Use of the VIPRE computer code at BVPS will not create the possibility of a new or different kind of accident from any accident previously evaluated because the code is an evaluation tool. It is not an accident initiator. Thus, its use can not create a new or different kind of accident.

Radiological Changes

The radiological changes will not create the possibility of a new or different kind of accident from any previously evaluated because they do not affect how components or systems are operated, nor do they create new components or systems failure modes.

Therefore, in conclusion, none of the proposed changes create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

Response: No. The proposed changes will not involve a significant reduction in a margin of safety.

EPU Related Changes

The proposed changes will not alter the manner in which safety limits, limiting safety system settings or limiting conditions for operation are determined. The proposed changes to Technical Specification limits are being made to provide adequate margin such that the BVPS units can be operated in a safe manner under the EPU conditions. These revisions will not adversely impact plant safety because they will not adversely affect the ability of systems, structures or components, including the Unit 1 replacement steam generators, important to the mitigation and control of design basis accident conditions, to perform their function. The Unit 2 steam generator TIG welded sleeves repair limit change does not involve a significant reduction in a margin of safety because it ensures that the structural integrity of tubes that are sleeved is maintained, thus precluding failure of a sleeve under EPU conditions. As determined by the new analysis, the new steam generator TIG welded sleeve repair limit will maintain a comparable margin of safety to the previous analysis. In addition, the proposed changes will not affect the ability of safety systems to ensure that the facility can be maintained in a shutdown or refueling condition for extended periods of time.

Operation at the EPU power level will not involve a significant reduction in a margin of safety. Extensive analyses of the primary fission product barriers have concluded that all relevant design criteria remain satisfied, both from the standpoint of the integrity of the primary fission product barrier and from the standpoint of compliance with the regulatory acceptance criteria. As appropriate, all evaluations have been performed using methods that have been both reviewed and approved by the Nuclear Regulatory Commission (NRC) or that are in compliance with applicable regulatory review guidance and standards.

Unit 1 Replacement Steam Generators

The steam generator tube integrity provides the margin of safety. The tubing in the RSGs is designed and evaluated consistent with the margins of safety specified in the ASME Code, Section III. The program for periodic inservice inspection provides sufficient time to take proper and timely corrective action if tube degradation is present.

The ASME Section XI basis for the 40% through wall plugging limit is applicable to the RSGs just as it was to the OSGs. A Regulatory Guide 1.121 analysis was performed to confirm the applicability of the 40% through wall plugging limit. As a result, there is no reduction in tube integrity for the RSGs.

The proposed changes to steam generator water level setpoints do not alter the reactor trip system/engineered safety feature actuation system setpoint analysis methodology, or the associated accident analysis methodology or acceptance criteria. The uncertainty calculations to establish the steam generator water level setpoints incorporate the recommendations in Westinghouse NSAL-03-9, "Steam Generator Water Level Uncertainties," September 22, 2003. The safety analyses for these accidents have been performed at the EPU power level and show acceptable results. Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

The proposed change to the steam generator water level used to verify steam generator operability in Modes 4 and 5 does not alter the steam generator water level uncertainty and setpoint analysis methodology or the associated natural circulation analysis methodology or acceptance criteria. Natural circulation calculations have been performed for the Unit 1 replacement steam generators at the EPU power level and show acceptable results. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

The changes to update the wording and content of the Technical Specification to provide clarification and to incorporate wording enhancements, are administrative changes that provide clarifications.

The proposed changes do not alter the requirements for tube integrity, tube inspection or tube plugging limit; therefore, they do not involve a significant reduction in a margin of safety.

Non-EPU Related Changes

The proposed deletion of the Power Range, Neutron Flux High Negative Rate Trip will not involve a significant reduction in a margin of safety because the DNBR will remain above its limit, with or without the trip for a dropped RCCA event.

Deletion of the Boron Injection Tank (BIT) boron concentration Technical Specification will not involve a significant reduction in a margin of safety because the BIT as a source of boron was not credited in the EPU analysis. The modification to the BIT flow path Technical Specification will not involve a significant reduction in a margin of safety increase because the flow path isolation requirements are retained.

Use of the VIPRE computer code at BVPS will not involve a significant reduction in a margin of safety increase because the code is used to establish a margin of safety such that core damage will not occur.

Radiological Changes

The radiological changes will not involve a significant reduction in a margin of safety because BVPS compliance with the limits set forth in 10 CFR 20, 10 CFR 50, Appendix I, 40 CFR 190 and 10 CFR 50.67, as supplemented by Regulatory Guide 1.183, will be maintained following approval of the requested EPU.

A FENOC assessment of the cumulative affect of the proposed changes provides reasonable expectation that collectively they will not result in a significant reduction in the overall margin of safety. The results of the analyses demonstrate that the applicable design and safety criteria and regulatory requirements will continue to be met following approval of the proposed changes. An assessment of the proposed changes to Technical Specification limits has determined that that collectively they do not involve a significant reduction in a margin of safety.

Therefore, in conclusion, none of the proposed changes involve a significant reduction in a margin of safety.

Based on the above, FENOC concludes that the proposed amendments present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements/Criteria

A review of 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants" (Reference 18), was conducted to assess the potential impact associated with the proposed changes. The following table lists the General Design Criteria (GDC) potentially impacted. An assessment was made of the need for a modification to the

Updated Final Safety Analysis Report (UFSAR) description of BVPS design conformance to the GDC.

General Design Criteria	
4	Environmental and Dynamic Effects Design Bases
10	Reactor Design
14	Reactor Coolant Pressure Boundary
15	Reactor Coolant System Design
19	Control Room
20	Protection System Functions
21	Protection Systems Reliability and Testability
22	Protection System Independence
23	Protection System Failure Modes
26	Reactivity Control System Redundancy and Capability
30	Quality of Reactor Coolant Pressure Boundary
31	Fracture Prevention of Reactor Coolant Pressure Boundary
32	Inspection of Reactor Coolant Pressure Boundary
35	Emergency Core Cooling

5.2.1 Discussion of Impacts

An assessment of the proposed changes concluded that there are no exceptions to any of the listed GDCs, and that there is no impact on the BVPS design conformance descriptions in the Unit 1 or Unit 2 UFSARs.

5.2.2 Conclusions

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

Section 11.0 of Enclosure 2 contains a review of the environmental impacts associated with the EPU. This review concluded that there are no major issues with the current NPDES permits or other plant administrative limits due to the proposed EPU.

The review has determined that the proposed amendment would change requirements with respect to installation or use of facility components located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendments do not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendments meet the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

7.0 REFERENCES

1. Regulatory Guide 1.183 "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors".
2. WCAP-15025-P-A, "Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids," April 1999.
3. FENOC Letter L-04-073, License Amendment Requests 317 and 190, dated June 2, 2004.
4. WCAP-11394-P-A, "Methodology for the Analysis of the Dropped Rod Event", Westinghouse Proprietary Class 2, R. L. Haessler, et al, January 1990.
5. NRC Safety Evaluation Report for Topical Report WCAP-11394 (P), "Methodology for the Analysis of the Dropped Rod Event", TAC No. 65674, letter dated October 23, 1989.
6. NRC Safety Evaluation Report for Beaver Valley Power Station Unit 1 Amendment 62, letter dated January 26, 1983.
7. EPRI Technical Report No. 1003138, Revision 6, "PWR SG Examination Guidelines," October 2002.
8. NEI 97-06, Revision 1, "Steam Generator Program Guidelines," January 2001.
9. WCAP-13483, "Beaver Valley Units 1 and 2 Westinghouse Series 51 Steam Generator Sleeving Report, Laser Welded Sleeves", Revision 2, October 2002.
10. NUREG-1431, Revision 3, "Standard Westinghouse Technical Specifications Westinghouse Plants", June 2004.
11. WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis", October 1999.
12. NRC Safety Evaluation Report for Beaver Valley Power Station Units 1 and 2, Amendments 243 and 122, letter dated September 24, 2001.
13. Westinghouse NSAL-03-9, "Steam Generator Water Level Uncertainties," September 22, 2003.

14. Draft Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes (For Comment)," August 1976.

15. NRC Safety Evaluation Report, "Acceptance for Referencing of Licensing Topical Report WCAP-14565, VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis (TAC NO. M98666)", January 19, 1999.

16. NRC Issuance of Amendment letter dated August 30, 2001, Beaver Valley Power Station License Amendments 241 (Unit 1) and 121 (Unit 2).

17. NRC Issuance of Amendment letter dated September 10, 2003, Beaver Valley Power Station License Amendments 257 (Unit 1) and 139 (Unit 2).

18. 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants".

Attachment A-1

Beaver Valley Power Station, Unit No. 1
Proposed Technical Specification Changes

License Amendment Request No. 302

The following is a list of the affected pages:

Page	Pending LAR	Page	Pending LAR
License Page 3		3/4 4-10d	
VI		3/4 4-10e	328
1-1		3/4 4-10f	328
2-1		3/4 4-10g	
3/4 1-16		3/4 4-10h	
3/4 3-2		3/4 4-18	321
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3/4 3-5		3/4 4-21	
3/4 3-5a		3/4 5-1	
3/4 3-7		3/4 5-3	326
3/4 3-11		3/4 5-4 *	
3/4 3-15	317	3/4 5-5 *	
3/4 3-18	317	3/4 5-6	321 & 326
3/4 3-19a	327	3/4 5-7	
3/4 4-2d		3/4 5-7a	
3/4 4-6		3/4 5-8	
3/4 4-8		3/4 7-1	321
3/4 4-9	322 & 328	3/4 7-2	
3/4 4-10		3/4 7-4	
3/4 4-10a		3/4 7-7	
3/4 4-10b	322 & 328	3/4 7-8	
3/4 4-10c	322	6-19	310 & 318

* No changes are proposed. The page is included for information only.

(3) FENOC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) FENOC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use in amounts as required any byproduct, source, or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components;

(5) FENOC, pursuant to the Act and 10 CFR Parts 30, and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This amended license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter 1: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

FENOC is authorized to operate the facility at a steady state reactor core power level of ~~2689~~ 2900 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 243, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

(3) Auxiliary River Water System

(Deleted by Amendment No. 8)

INDEX

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

1.0 DEFINITIONS

DEFINED TERMS

1.1 The DEFINED TERMS of this section appear in capitalized type and are applicable throughout these Technical Specifications.

THERMAL POWER

1.2 THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

RATED THERMAL POWER

1.3 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant ~~of 2689~~ as specified in the Licensing Requirements Manual, and shall not exceed 2900 MWt.

OPERATIONAL MODE

1.4 An OPERATIONAL MODE shall correspond to any one inclusive combination of core reactivity condition, power level and average reactor coolant temperature specified in Table 1.1.

ACTION

1.5 ACTION shall be those additional requirements specified as corollary statements to each principle specification and shall be part of the specifications.

OPERABLE - OPERABILITY

1.6 A system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s). Implicit in this definition shall be the assumption that all necessary attendant instrumentation, controls, normal and emergency electric power sources, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related safety function(s).

2.0 SAFETY LIMITS

2.1 SAFETY LIMITS

REACTOR CORE

2.1.1 The combination of THERMAL POWER, pressurizer pressure, and the highest operating loop coolant temperature (T_{avg}) shall not exceed the limits specified in the COLR; and the following Safety Limits shall not be exceeded:

2.1.1.1 The departure from nucleate boiling ratio (DNBR) shall be maintained ≥ 1.17 for WRB-1 DNB correlation for Vantage 5H (V5H) fuel assemblies, and ≥ 1.14 for WRB-2M DNB correlation for Robust Fuel Assemblies (RFA).

2.1.1.2 The peak fuel centerline temperature shall be maintained ≤ 4700°F.

APPLICABILITY: MODES 1 and 2.

ACTION:

If Safety Limit 2.1.1 is violated, restore compliance and be in HOT STANDBY within 1 hour.

REACTOR COOLANT SYSTEM PRESSURE

2.1.2 The Reactor Coolant System pressure shall not exceed 2735 psig.

APPLICABILITY: MODES 1, 2, 3, 4 and 5.

ACTION:

MODES 1 and 2

Whenever the Reactor Coolant System pressure has exceeded 2735 psig, be in HOT STANDBY with the Reactor Coolant System pressure within its limit within 1 hour.

MODES 3, 4 and 5

Whenever the Reactor Coolant System pressure has exceeded 2735 psig, reduce the Reactor Coolant System pressure to within its limit within 5 minutes.

REFUELING WATER STORAGE TANK (RWST)

LIMITING CONDITION FOR OPERATION

3.1.2.8 The RWST shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 & 4.

ACTION:

With the refueling water storage tank inoperable, restore the tank to OPERABLE status within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.8 The RWST shall be verified OPERABLE:

a. At least once per 7 days by:

1. Verifying the boron concentration is between 2,400 and 2,600 ppm, and

2. Verifying a contained volume between 439,050 gallons and 441,100 gallons of borated water.

b. At least once per 24 hours by verifying the RWST solution temperature is ≥ 45°F and ≤ ~~55~~65°F when the RWST ambient air temperature is < 45°F or > ~~55~~65°F.

TABLE 3.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION

	FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	ALLOWABLE VALUE	APPLICABLE MODES	ACTION
1.	Manual Reactor Trip	2	1	2	Not Applicable	1, 2, 3(3), 4(3) and 5(3)	12
2.	Power Range, Neutron Flux						
	a. High Setpoint	4	2	3	≤ 109.5% of RATED THERMAL POWER	1, 2	2
	b. Low Setpoint	4	2	3	≤ 25.5% OF RATED THERMAL POWER	1(1), 2	2
3.	Power Range, Neutron Flux High Positive Rate	4	2	3	≤ 5.5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	1, 2	2
4.	~~Power Range, Neutron Flux High Negative Rate~~DELETED	~~4~~	~~2~~	~~3~~	~~≤ 5.5% of RATED THERMAL POWER with a time constant ≥ 2 seconds~~	~~1, 2~~	~~2~~
5.	Intermediate Range, Neutron Flux	2	1	2	≤ 27.9% of RATED THERMAL POWER	1(1), 2, 3(3), 4(3) and 5(3)	3
6.	Source Range, Neutron Flux						
	a. With Rod Withdrawal Capability	2	1	2	≤ 1.3 x 10^5 counts per second	2(2), 3(3), 4(3) and 5(3)	4
	b. With All Rods Fully Inserted and Without Rod Withdrawal Capability	2	0	1	Not Applicable	3(8), 4(8), and 5(8)	5

This page includes changes proposed by LAR 327.

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

	FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	ALLOWABLE VALUE	APPLICABLE MODES	ACTION
7.	Overtemperature ΔT	3	2	2	See Table Notation (A)	1, 2	7
8.	Overpower ΔT	3	2	2	See Table Notation (B)	1, 2	7
9.	Pressurizer Pressure-Low (Above P-7)	3	2	2	≥ 1941 psig	1, 2	7
10.	Pressurizer Pressure-High	3	2	2	≤ 2389 psig	1, 2	7
11.	Pressurizer Water Level-High (Above P-7)	3	2	2	≤ 92.5% of instrument span	1, 2	7
12.	Loss of Flow - Single Loop (Above P-8)	3/loop	2/loop in any operating loop	2/loop in each operating loop	≥ 89.8% of indicated loop flow	1	7
13.	Loss of Flow - Two Loops (Above P-7 and below P-8)	3/loop	2/loop in two operating loops	2/loop each operating loop	≥ 89.8% of indicated loop flow	1	7
14.	Steam Generator Water Level-Low-Low (Loop Stop Valves Open)	3/loop	2/loop	2/loop	≥ ~~19.6~~ 19.1% of narrow range instrument span-each steam generator	1, 2	7

TABLE 3.3-1 (Continued)

TABLE NOTATION

(1) Trip function may be manually bypassed in this Mode above P-10.

(2) Trip function may be manually bypassed in this Mode above P-6.

(3) With the reactor trip system breakers in the closed position and the control rod drive system capable of rod withdrawal.

(8) In this condition, source range Function does not provide reactor trip but does provide indication.

(A): Overtemperature ΔT

The Overtemperature ΔT Function Allowable Value shall not exceed the following nominal trip setpoint by more than 0.5% ΔT span for the ΔT channel, 0.5% ΔT span for the T_{avg} channel, 0.5% ΔT span for the Pressurizer Pressure channel and 0.5% ΔT span for the $f(\Delta I)$ channel.

$$\Delta T \le \Delta T_0 \left[K_1 - K_2 \left(\frac{1+\tau_1 S}{1+\tau_2 S}\right)[T - T'] + K_3 (P - P') - f(\Delta I)\right]$$

$$\boxed{\frac{1}{(1+\tau_5 S)}}$$

$$\boxed{\frac{1}{(1+\tau_4 S)}}$$

where: ΔT is measured RCS ΔT, °F.

ΔT_0 is loop specific indicated ΔT at RATED THERMAL POWER, °F.

T is measured RCS average temperature, °F.

T' is T_{avg} at RATED THERMAL POWER specified in the COLR.

P is measured pressurizer pressure, psia.

P' is nominal pressurizer pressure specified in the COLR.

$\frac{1+\tau_1 S}{1+\tau_2 S}$ is the function generated by the lead-lag compensator for T_{avg}.

τ_1 & τ_2 are the time constants utilized in the lead-lag compensator for T_{avg} specified in the COLR.

$\frac{1}{(1+\tau_4 S)}$ is the function generated by the lag compensator for measured ΔT.

$\frac{1}{(1+\tau_5 S)}$ is the function generated by the lag compensator for measured T_{avg}.

τ_4 & τ_5 are the time constants utilized in the lag compensators for the ΔT and T_{avg}, respectively, specified in the COLR.

S is the Laplace transform operator, sec^{-1}.

K_1 is specified in the COLR.

K_2 is specified in the COLR.

K_3 is specified in the COLR.

$f(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers as specified in the COLR.

TABLE NOTATION (Continued)

(B): Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following nominal trip setpoint by more than 0.5% ΔT span for the ΔT channel and 0.5% ΔT span for the T_{avg} channel.

$$\Delta T \leq \Delta T_0 \left[K_4 - K_5\left(\frac{\tau_3 S}{1+\tau_3 S}\right) T - K_6 \left[T - T''\right]\right]$$

$$\boxed{\frac{1}{(1+\tau_5 S)}}$$

$$\boxed{\frac{1}{(1+\tau_4 S)}}$$

where: ΔT is measured RCS ΔT, °F.

ΔT_0 is loop specific indicated ΔT at RATED THERMAL POWER, °F.

T is measured RCS average temperature, °F.

T″ is T_{avg} at RATED THERMAL POWER specified in the COLR.

K_4 is specified in the COLR.

K_5 is specified in the COLR.

K_6 is specified in the COLR.

$\frac{\tau_3 S}{1+\tau_3 S}$ is the function generated by the rate lag compensator for T_{avg}.

τ_3 is the time constant utilized in the rate lag compensator for T_{avg} specified in the COLR.

$\frac{1}{(1+\tau_4 S)}$ is the function generated by the lag compensator for measured ΔT.

$\frac{1}{(1+\tau_5 S)}$ is the function generated by the lag compensator for measured T_{avg}.

τ_4 & τ_5 are the time constants utilized in the lag compensators for the ΔT and T_{avg}, respectively, specified in the COLR.

S is the Laplace transform operator, sec^{-1}.

TABLE 3.3-1 (Continued)

ACTION 7 - With the number of OPERABLE channels[6] one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours, and

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.1.

ACTION 8 - With the number of OPERABLE channels one less than the Total Number of Channels and with the THERMAL POWER level above P-~~7~~2, place the inoperable channel in the tripped condition within 6 hours; operation may continue until performance of the next required CHANNEL FUNCTIONAL TEST.

ACTION 9 - Not applicable.

ACTION 10 - Not applicable.

ACTION 11 - With less than the Minimum Number of Channels OPERABLE, operation may continue provided the inoperable channel is placed in the tripped condition within 6 hours.

ACTION 12 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within the next 6 hours and/or open the reactor trip breakers.

ACTION 39 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the reactor trip breakers within the next hour.

---

(6) An OPERABLE hot leg channel consists of: 1) three RTDs per hot leg, or 2) two RTDs per hot leg with the failed RTD disconnected and the required bias applied.

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

	Functional Unit	Channel Check	Channel Calibration	Channel Functional Test	Modes in Which Surveillance Required
1.	Manual Reactor Trip	N.A.	N.A.	S/U(1), R(10)	N.A.
2.	Power Range, Neutron Flux				
	a. High Setpoint	S	D(2), M(3) and Q(6)	Q	1, 2
	b. Low Setpoint	S	R(6)	S/U(1)	2
3.	Power Range, Neutron Flux, High Positive Rate	N.A.	R(6)	Q	1, 2
4.	~~Power Range, Neutron Flux, High Negative Rate~~ DELETED	~~N.A.~~	~~R(6)~~	~~Q~~	~~1, 2~~
5.	Intermediate Range, Neutron Flux	S	R(6)	S/U(1)	1, 2, 3(14), 4(14), 5(14)
6.	Source Range(15), Neutron Flux				
	a. With Rod Withdrawal Capability	S	R(6)	Q(8)	2, 3(14), 4(14) and 5(14)
	b. With All Rods Fully Inserted and Without Rod Withdrawal Capability	S	R(6)	Q(8)	3, 4 and 5
7.	Overtemperature ΔT	S	R(6)	Q	1, 2
8.	Overpower ΔT	S	R	Q	1, 2
9.	Pressurizer Pressure-Low	S	R	Q	1, 2
10.	Pressurizer Pressure-High	S	R	Q	1, 2
11.	Pressurizer Water Level-High	S	R	Q	1, 2

This page includes changes proposed by LAR 317.

TABLE 3.3-3

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	ALLOWABLE VALUE	APPLICABLE MODES	ACTION
1. SAFETY INJECTION AND FEEDWATER ISOLATION						
a. Manual Initiation	2	1	2	Not Applicable	1, 2, 3, 4	18
b. Automatic Actuation Logic	2	1	2	Not Applicable	1, 2, 3, 4	13, 36
c. Containment Pressure-High	3	2	2	≤ 5.33 psig	1, 2, 3	14
d. Pressurizer Pressure-Low	3	2	2	≥ 1841 psig	1, 2, 3(1)	14
e. Steamline Pressure-Low	3/loop	2/loop any loop	2/loop any loop	≥ 495.8 psig steam-line pressure*	1, 2, 3(1)	14

* Time constants utilized in the lead-lag controllers for Steam Line Pressure-Low are $\tau_1 \geq 50$ seconds and $\tau_2 \leq 5$ seconds. CHANNEL CALIBRATION shall ensure that these time constants are adjusted to these values.

This page includes changes proposed by LAR 317.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	ALLOWABLE VALUE	APPLICABLE MODES	ACTION
4. STEAM LINE ISOLATION						
a. Manual	2/steam line	1/steam line	2/operat-ing steam line	Not Applicable	1, 2, 3	18
b. Automatic Actuation Logic	2	1	2	Not Applicable	1, 2, 3	13
c. Containment Pressure Intermediate-High-High	3	2	2	≤ 7.33 psig	1, 2, 3	14
d. Steamline Pressure-Low	3/loop	2/loop any loop	2/loop any loop	≥ 495.8 psig steam line pressure*	1, 2, $3^{(1)}$	14
e. Steamline Pressure Rate-High Negative	3/loop	2/loop any loop	2/operat-ing loop	≤ 104.2 psi with a time constant ≥ 50 seconds	$3^{(2)}$	14
5. TURBINE TRIP & FEEDWATER ISOLATION						
a. Steam Generator Water Level--High-High, P-14	3/loop	2 loop in any operating loop	2/loop in each operating loop	≤ ~~81.7~~90.2% of narrow range instrument span each steam generator	1, 2, 3	14

* Time constants utilized in the lead-lag controllers for Steam Line Pressure-Low are $\tau_1 \geq 50$ seconds and $\tau_2 \leq 5$ seconds. CHANNEL CALIBRATION shall ensure that these time constants are adjusted to these values.

This page includes changes proposed by LAR 327.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	ALLOWABLE VALUE	APPLICABLE MODES	ACTION
7. AUXILIARY FEEDWATER						
a. Steam Gen. Water Level-Low-Low (Loop Stop Valves Open)						
i. Start Turbine Driven Pump	3/stm. gen.	2/stm. gen. any stm. gen.	2/stm. gen.	≥ ~~19.6~~19.1% of narrow range instrument span each steam generator	1, 2, 3	14
ii. Start Motor Driven Pumps	3/stm. gen. any 2 stm. gen.	2/stm. gen. any 2 stm. gen.	2/stm. gen.	≥ ~~19.6~~19.1% of narrow range instrument span each steam generator	1, 2, 3	14
b. Undervoltage-RCP (Start Turbine Driven Pump)	(3)-1/bus	2	2	≥ 71.2% rated RCP bus voltage	1	14
c. S.I. (Start All Auxiliary Feedwater Pumps)	See 1 above (all S.I. initiating functions and requirements)					
d. (Deleted)						
e. Trip of Main Feedwater Pumps (Start Motor Driven Pumps)	1/pump	1	1	Not Applicable	1, 2, 3	18

LIMITING CONDITION FOR OPERATION (Continued)

ACTION:

a. With less than the above required loops OPERABLE, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible; be in COLD SHUTDOWN within 20 hours.

b. With no coolant loop in operation, suspend all operation involving a reduction in boron concentration of the Reactor Coolant system and immediately initiate corrective action to return the required coolant loop to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.3.1 The required residual heat removal loop(s) shall be determined OPERABLE per Specification 4.0.5.

4.4.1.3.2 The required reactor coolant pump(s), if not in operation, shall be determined to be OPERABLE once per 7 days by verifying correct breaker alignments and indicated power availability.

4.4.1.3.3 The required steam generator(s) shall be determined OPERABLE by verifying secondary side level equivalent to ~~12~~28% narrow range at least once per 12 hours.

4.4.1.3.4 At least one coolant loop shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

3/4.4.3 SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.4.3 All pressurizer code safety valves shall be OPERABLE with a lift setting* of 2485 PSIG ~~±1% 3~~± 3%.**

APPLICABILITY: MODES 1, 2 and 3,
MODE 4 with all RCS cold leg temperatures > the enable temperature specified in the PTLR.

ACTION:

a. With one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in HOT SHUTDOWN with any RCS cold leg temperature ≤ the enable temperature specified in the PTLR and apply RCS overpressure protection requirements in accordance with Specification 3.4.9.3 within 12 hours.

b. With a pressurizer code safety valve having discharged liquid water from a water solid pressurizer to mitigate an overpressure event, be in at least HOT STANDBY within the next 6 hours, and in HOT SHUTDOWN with any RCS cold leg temperature ≤ the enable temperature specified in the PTLR and apply RCS overpressure protection requirements in accordance with Specification 3.4.9.3 within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.3 No additional requirements other than those required by Specification 4.0.5.

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* The Lift Setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

** Within ± 1% following pressurizer code safety valve testing.

3/4.4.5 STEAM GENERATORS

LIMITING CONDITION FOR OPERATION

3.4.5 Each steam generator shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one or more steam generators inoperable, restore the inoperable generator(s) to OPERABLE status prior to increasing T_{avg} above 200°F.

SURVEILLANCE REQUIREMENTS

4.4.5.1 Steam Generator Sample Selection and Inspection - Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 4.4-1.

4.4.5.2 Steam Generator Tube Sample Selection and Inspection - The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 4.4-2. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 4.4.5.3 and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 4.4.5.4. Steam generator tubes shall be examined in accordance with Article 8 of Section V ("Eddy current Examination of Tubular Products") and Appendix IV to Section XI ("Eddy Current Examination of Nonferromagnetic Steam Generator Heat Exchanger Tubing") of the applicable year and addenda of the ASME Boiler and Pressure Vessel Code required by 10CFR50, Section 50.55a(g). ~~When applying the exceptions of 4.4.5.2.a through 4.4.5.2.c, previous defects or imperfections in the area repaired by sleeving are not considered an area requiring reinspection.~~The tubes selected for each inservice inspection shall include at least 3 percent of the total number of tubes in all steam generators; the tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50 percent of the tubes inspected shall be from these critical areas.

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

    1. All nonplugged tubes that previously had detectable wall penetrations greater than 20 percent, and

This page includes changes proposed by LARs 322 and 328.

2. Tubes in those areas where experience has indicated ~~potential problems, and~~

~~3. Except for Alloy 800 leak limiting sleeves, at least 3 percent of the total number of sleeved tubes in all three steam generators. A sample size less than 3 percent is acceptable provided all the sleeved tubes in the steam generator(s) examined during the refueling outage are inspected. All inservice Alloy 800 leak limiting sleeves shall be inspected over the full length using a plus point coil or equivalent qualified technique during each refueling outage. These inspections will include both the tube and the sleeve, and~~

~~4~~3. A tube inspection (pursuant to Specification 4.4.5.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube ~~or sleeve~~ inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

~~5. Indications left in service as a result of application of the tube support plate voltage-based repair criteria (4.4.5.4.a.10) shall be inspected by bobbin coil probe during all future refueling outages.~~

c. The tubes selected as the second and third samples (if required by Table 4.4-2) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found, and

2. The inspections include those portions of the tubes where imperfections were previously found.

~~d. Implementation of the steam generator tube-to-tube support plate repair criteria requires a 100-percent bobbin coil inspection for hot-leg and cold-leg tube support plate intersections down to the lowest cold-leg tube support plate with known outside diameter stress corrosion cracking (ODSCC) indications. The determination of the lowest cold-leg tube support plate intersections having ODSCC indications shall be based on the performance of at least a 20-percent random sampling of tubes inspected over their full length.~~

~~e.[3] Implementation of the steam generator WEXTEX expanded region inspection methodology (W*), requires a 100-percent rotating probe inspection of the hot leg tubesheet W* distance.~~

The results of each sample inspection shall be classified into one of the following three categories:

~~[3] Applicable only to Cycle 17.~~

Category	Inspection Results
C-1	Less than 5 percent of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1 percent of the total tubes inspected are defective, or between 5 percent and 10 percent of the total tubes inspected are degraded tubes.
C-3	More than 10 percent of the total tubes inspected are degraded tubes or more than 1 percent of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes ~~or sleeves~~ must exhibit significant (greater than 10 percent) further wall penetrations to be included in the above percentage calculations.

4.4.5.3 Inspection Frequencies - The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection shall be performed after 6 Effective Full Power Months (EFPM) but within 24 ~~calendar months~~EFPM of initial criticality or following steam generator replacement. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections ~~following service under All Volatile Treatment (AVT) conditions~~, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

Note: Inservice inspection is not required during the steam generator replacement outage.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 4.4-2 ~~requires a third sample inspection whose results~~ fall into Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until ~~a~~ the subsequent inspections satisfy the criteria of specification 4.4.5.3.a; the interval may then be extended to a maximum of once per 40 months.~~demonstrates that a third sample inspection is not required.~~

SURVEILLANCE REQUIREMENTS (Continued)

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 4.4-2 during the shutdown subsequent to any of the following conditions:

1. Primary-to-secondary tube leaks (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.4.6.2,

2. A seismic occurrence greater than the Operating Basis Earthquake,

3. A loss-of-coolant accident requiring actuation of the engineered safeguards, or

4. A main steamline or feedwater line break.

4.4.5.4 Acceptance Criteria

a. As used in this Specification:

1. Imperfection means an exception to the dimensions, finish or contour of a tube ~~or sleeve~~ from that required by fabrication drawings or specifications. Eddy-current testing indications below 20 percent of the nominal tube wall thickness, if detectable, may be considered as imperfections.

2. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either inside or outside of a tube ~~or sleeve~~.

3. Degraded Tube means a tube ~~or sleeve~~ containing imperfections greater than or equal to 20 percent of the nominal wall thickness caused by degradation.

4. Percent Degradation means the percentage of the tube ~~or sleeve~~ wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the plugging ~~or repair~~ limit. A tube containing a defect is defective. Any tube which does not permit the passage of the eddy-current inspection probe shall be deemed a defective tube.

This page includes changes proposed by LARs 322 and 328.

SURVEILLANCE REQUIREMENTS (Continued)

6. Plugging ~~or Repair~~ Limit means the imperfection depth ~~at or beyond which the~~ tube shall be removed from service by plugging ~~or repaired by sleeving in the affected area~~ because it may become unserviceable prior to the next inspection. The plugging limit is equal to 40 percent of the nominal tube wall thickness.~~The plugging or repair limit imperfection depths are specified in percentage of nominal wall thickness as follows:~~

~~a) Original tube wall 40%~~

~~1.0) This definition does not apply to tube support plate intersections for which the voltage-based repair criteria are being applied. Refer to 4.4.5.4.a.10 for the repair limit applicable to these intersections.~~

~~2.0)(4) This definition does not apply to service induced degradation identified in the W* distance. Service induced degradation identified in the W* distance or less than eight inches below the top of tube sheet (TTS), which ever is greater, shall be repaired on detection.~~

~~b) ABB Combustion Engineering TIG welded sleeve wall 32%~~

~~c) Westinghouse laser welded sleeve wall 25%~~

~~d) Westinghouse Alloy 800 leak limiting sleeve(4): Plug on detections of any service induced imperfection, degradation or defect in the (a) sleeve and/or (b) pressure boundary portion of the original tube wall in the sleeve/tube assembly (i.e., the sleeve to tube joint).~~

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steamline or feedwater line break as specified in 4.4.5.3.c, above.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot-leg side) completely around the U-bend to the top support of the cold-leg., ~~excluding the portion of the tube within the tubesheet below the W* distance, the tube to tubesheet weld and the tube end extension. This exclusion is applicable only to Cycle 17. This~~

~~exclusion does not apply to steam generator tubes with sleeves installed within the tubesheet region.~~

~~9. Tube Repair refers to sleeving which is used to maintain a tube in-service or return a tube to service. This includes the removal of plugs that were installed as a corrective or preventive measure. The following sleeve designs have been found acceptable:~~

~~a) ABB Combustion Engineering TIG Welded Sleeves, CEN-629-P, Revision 02 and CEN-629-P Addendum 1.~~

~~b) Westinghouse laser welded sleeves, WCAP-13483, Revision 1.~~

~~** Applicable only to Cycle 17.~~

This page includes changes proposed by LARs 322 and 328.

This page includes changes proposed by LAR 322.

~~SURVEILLANCE REQUIREMENTS (Continued)~~

~~c) Westinghouse Alloy 800 leak limiting sleeves, WCAP-15919-P, Revision 00[1].~~

~~10. Tube Support Plate Plugging Limit is used for the disposition of an alloy 600 steam generator tube for continued service that is experiencing predominantly axially oriented outside diameter stress corrosion cracking confined within the thickness of the tube support plates. At tube support plate intersections, the plugging (repair) limit is based on maintaining steam generator tube serviceability as described below:~~

~~a) Steam generator tubes, whose degradation is attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with bobbin voltages less than or equal to 2.0 volts will be allowed to remain in service.~~

~~b) Steam generator tubes, whose degradation is attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with a bobbin voltage greater than 2.0 volts will be repaired or plugged, except as noted in 4.4.5.4.a.10.c below.~~

~~c) Steam generator tubes, with indications of potential degradation attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with a bobbin voltage greater than 2.0 volts but less than or equal to the upper voltage repair limit[1] may remain in service if a rotating pancake coil or acceptable alternative inspection does not detect degradation. Steam generator tubes, with indications of outside diameter stress corrosion cracking degradation with a bobbin voltage greater than the upper voltage repair limit[1] will be plugged or repaired.~~

~~d) If an unscheduled mid-cycle inspection is performed, the following mid-cycle repair limits apply instead of the limits identified in 4.4.5.4.a.10.a, 4.4.5.4.a.10.b, and 4.4.5.4.a.10.c.~~

~~(1) The upper voltage repair limit is calculated according to the methodology in Generic Letter 95-05 as supplemented.~~

~~(1) Applicable only to Cycle 17.~~

~~The mid-cycle repair limits are determined from the following equations:~~

$$V_{MURL} = \frac{V_{SL}}{1.0 + NDE + Gr\left(\frac{CL - \Delta t}{CL}\right)}$$

$$\cancel{V_{MLRL} = V_{MURL} - (V_{URL} - V_{LRL})}\left(\frac{CL - \Delta t}{CL}\right)$$

~~where:~~

$\cancel{V_{URL}}$	=	~~upper voltage repair limit~~
$\cancel{V_{LRL}}$	=	~~lower voltage repair limit~~
$\cancel{V_{MURL}}$	=	~~mid-cycle upper voltage repair limit based on time into cycle~~
$\cancel{V_{MLRL}}$	=	~~mid-cycle lower voltage repair limit based on~~ $\cancel{V_{MURL}}$ ~~and time into cycle~~
$\cancel{\Delta t}$	=	~~length of time since last scheduled inspection during which~~ $\cancel{V_{URL}}$ ~~and~~ $\cancel{V_{LRL}}$ ~~were implemented~~
~~CL~~	=	~~cycle length (the time between two scheduled steam generator inspections)~~
$\cancel{V_{SL}}$	=	~~structural limit voltage~~
~~Gr~~	=	~~average growth rate per cycle length~~
~~NDE~~	=	~~95 percent cumulative probability allowance for nondestructive examination uncertainty (i.e., a value of 20 percent has been approved by NRC)~~ ~~(2)~~

~~Implementation of these mid-cycle repair limits should follow the same approach as in TS 4.4.5.4.a.10.a, 4.4.5.4.a.10.b, and 4.4.5.4.a.10.c.~~

~~(2) The NDE is the value provided by the NRC in GL 95-05 as supplemented.~~

This page includes changes proposed by LAR 328.

SURVEILLANCE REQUIREMENTS (Continued)

~~11.[**] a) Bottom of WEXTEX Transition (BWT) is the highest point of contact between the tube and tubesheet at, or below the top of tubesheet, as determined by eddy current testing.~~

~~b) W* Distance is the non-degraded distance from the top of the tubesheet to the bottom of the W* length including the distance from the top of the tubesheet to the bottom of the WEXTEX transition (BWT) and Non-Destructive Examination (NDE) measurement uncertainties (i.e., W* distance = W* length + distance to BWT + NDE uncertainties).~~

~~c) W* Length is the length of tubing below the bottom of the WEXTEX transition (BWT) which must be demonstrated to be non-degraded in order for the tube to maintain structural and leakage integrity. For the hot leg, the W* length is 7.0 inches which represents the most conservative hot leg length defined in WCAP-14797, Revision 2.~~

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug ~~or repair~~ all tubes exceeding the plugging ~~or repair~~ limit) required by Table 4.4-2.

4.4.5.5 Reports

a. Within 15 days following the completion of each inservice inspection of steam generator tubes, the number of tubes plugged ~~or repaired~~ in each steam generator shall be submitted in a Special Report in accordance with 10 CFR 50.4.

b. The complete results of the steam generator tube ~~and sleeve~~ inservice inspection shall be submitted in a Special Report in accordance with 10 CFR 50.4 within 12 months following the completion of the inspection. This Special Report shall include:

1. Number and extent of tubes ~~and sleeves~~ inspected.

2. Location and percent of wall-thickness penetration for each indication of an imperfection.

3. Identification of tubes plugged ~~or repaired~~.

c. Results of steam generator tube inspections which fall into Category C-3 shall be reported to the Commission pursuant to Specification 6.6 prior to resumption of plant operation. The written report shall provide a description of investigations conducted to determine the cause of the tube degradation and corrective measures taken to prevent recurrence.

~~d. For implementation of the voltage based repair criteria to tube support plate intersections, notify the Commission prior to returning the steam generators to service (MODE 4) should any of the following conditions arise:~~

~~1. If estimated leakage based on the projected end-of-cycle (or if not practical, using the actual measured end-of-cycle) voltage distribution exceeds the leak limit (determined from the licensing basis dose calculation for the postulated main steamline break) for the next operating cycle. For Cycle 17, the postulated leakage resulting from the implementation of the voltage based repair criteria to tube support plate intersections shall be combined with the postulated leakage resulting from the implementation of the W* criteria to tubesheet inspection depth.~~

~~2. If circumferential crack-like indications are detected at the tube support plate intersections.~~

~~(3) Applicable only to Cycle 17.~~

This page includes changes proposed by LAR 328.

This page includes changes proposed by LAR 328.

~~SURVEILLANCE REQUIREMENTS (Continued)~~

~~3. If indications are identified that extend beyond the confines of the tube support plate.~~

~~4. If indications are identified at the tube support plate elevations that are attributable to primary water stress corrosion cracking.~~

~~5. If the calculated conditional burst probability based on the projected end of cycle (or if not practical, using the actual measured end-of-cycle) voltage distribution exceeds 1 X 10^{-2}, notify the Commission and provide an assessment of the safety significance of the occurrence.~~

~~e.[3] The aggregate calculated steam line break leakage from the application of tube support plate alternate repair criteria and W* inspection methodology shall be submitted in a Special Report in accordance with 10 CFR 50.4 within 90 days following return of the steam generators to service (MODE 4). In addition, the total number of indications that are identified from 1R16 rotating probe inspections that are performed as part of the W* inspections will be included in this report.~~

~~[3] Applicable only to Cycle 17.~~

TABLE 4.4-1

MINIMUM NUMBER OF STEAM GENERATORS TO BE

INSPECTED DURING INSERVICE INSPECTION

Preservice Inspection	No	Yes
No. of Steam Generators per Unit	Three	Three
First Inservice Inspection	All	Two
Second & Subsequent Inservice Inspections	One (1)	One (2)

Table Notation:

(1) The inservice inspection may be limited to one steam generator on a rotating schedule encompassing 9 percent of the tubes if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. Note that under some circumstances, the operating conditions in one or more steam generators may be found to be more severe than those in other steam generators. Under such circumstances the sample sequence shall be modified to inspect the most severe conditions.

(2) The other steam generator not inspected during the first inservice inspection shall be inspected. The third and subsequent inspections should follow the instructions described in (1) above.

TABLE 4.4-2

STEAM GENERATOR TUBE INSPECTION

1ST SAMPLE INSPECTION			2ND SAMPLE INSPECTION		3RD SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S tubes per S.G.	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug ~~or repair~~ defective tubes ~~defective tubes~~ and inspect additional ~~inspect additional~~ 2S tubes in this S.G.	C-1	None	N/A	N/A
			C-2	Plug ~~or repair~~ defective tubes and ~~tubes and~~ inspect additional 4S tubes in this S.G.	C-1	None
					C-2	Plug ~~or repair~~ defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N/A	N/A
	C-3	Inspect all tubes in this S.G., plug ~~or repair~~ defective tubes and inspect 2S tubes in each other S.G. Notification to NRC pursuant to Specification 6.6	All other S.G.s are C-1	None	N/A	N/A
			Some S.G.s are C-2 but no additional S.G.s are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional S.G. is C-3	Inspect all tubes in each S.G. and plug ~~or repair~~ defective tubes. Notification to NRC pursuant to Specification 6.6.	N/A	N/A

$s = \frac{9}{n}\%$ Where n is the number of steam generators inspected during an inspection.

This page includes changes proposed by LAR 321.

SPECIFIC ACTIVITY

LIMITING CONDITION FOR OPERATION

3.4.8 The specific activity of the primary coolant shall be limited to:

a. ≤ ~~0.10~~0.35µCi/gram DOSE EQUIVALENT I-131, and

b. ≤ 100/$\bar{E}$ µCi/gram.

APPLICABILITY: MODES 1, 2, 3, 4 and 5.

ACTION:

MODES 1, 2, and 3*

a. With the specific activity of the primary coolant > ~~0.10~~0.35 µCi/gram DOSE EQUIVALENT I-131(1) for more than 48 hours during one continuous time interval or exceeding the limit line shown on Figure 3.4-1, be in HOT STANDBY with T_{avg} < 500°F within 6 hours.

b. With the specific activity of the primary coolant > 100/$\bar{E}$ µCi/gram, be in HOT STANDBY with T_{avg} < 500°F within 6 hours.

MODES 1, 2, 3, 4 and 5

a. With the specific activity of the primary coolant > ~~0.10~~0.35 µCi/gram DOSE EQUIVALENT I-131 or > 100/$\bar{E}$ µCi/gram, perform the sampling and analysis requirement of item 4a of Table 4.4-12 until the specific activity of the primary coolant is restored to within its limits.

SURVEILLANCE REQUIREMENTS

4.4.8 The specific activity of the primary coolant shall be determined to be within the limits by performance of the sampling and analysis program of Table 4.4-12.

* With T_{avg} ≥ 500°F

(1) Specification 3.0.4.c is applicable.

TABLE 4.4-12

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	MINIMUM FREQUENCY	MODES IN WHICH SURVEILLANCE REQUIRED
1. Gross Activity Determination	3 times per 7 days with a maximum time of 72 hours between samples.	1, 2, 3, 4
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	1 per 14 days	1,
3. Radiochemical for $\overline{E}$ Determination	1 per 6 months	1,
4. Isotopic Analysis for Iodine Including I-131, I-133, and I-135	a) Once per 4 hours, whenever the specific activity exceeds ~~0.10~~ 0.35 µCi/gram DOSE EQUIVALENT I-131 or 100/$\overline{E}$ µCi/gram, and	1#, 2#, 3#, 4#, 5#
	b) One sample between 2 & 6 hours following a THERMAL POWER change exceeding 15 percent of the RATED THERMAL POWER within a one hour period.	1, 2, 3

#Until the specific activity of the primary coolant system is restored within its limits.

Replace with Insert A1-1.

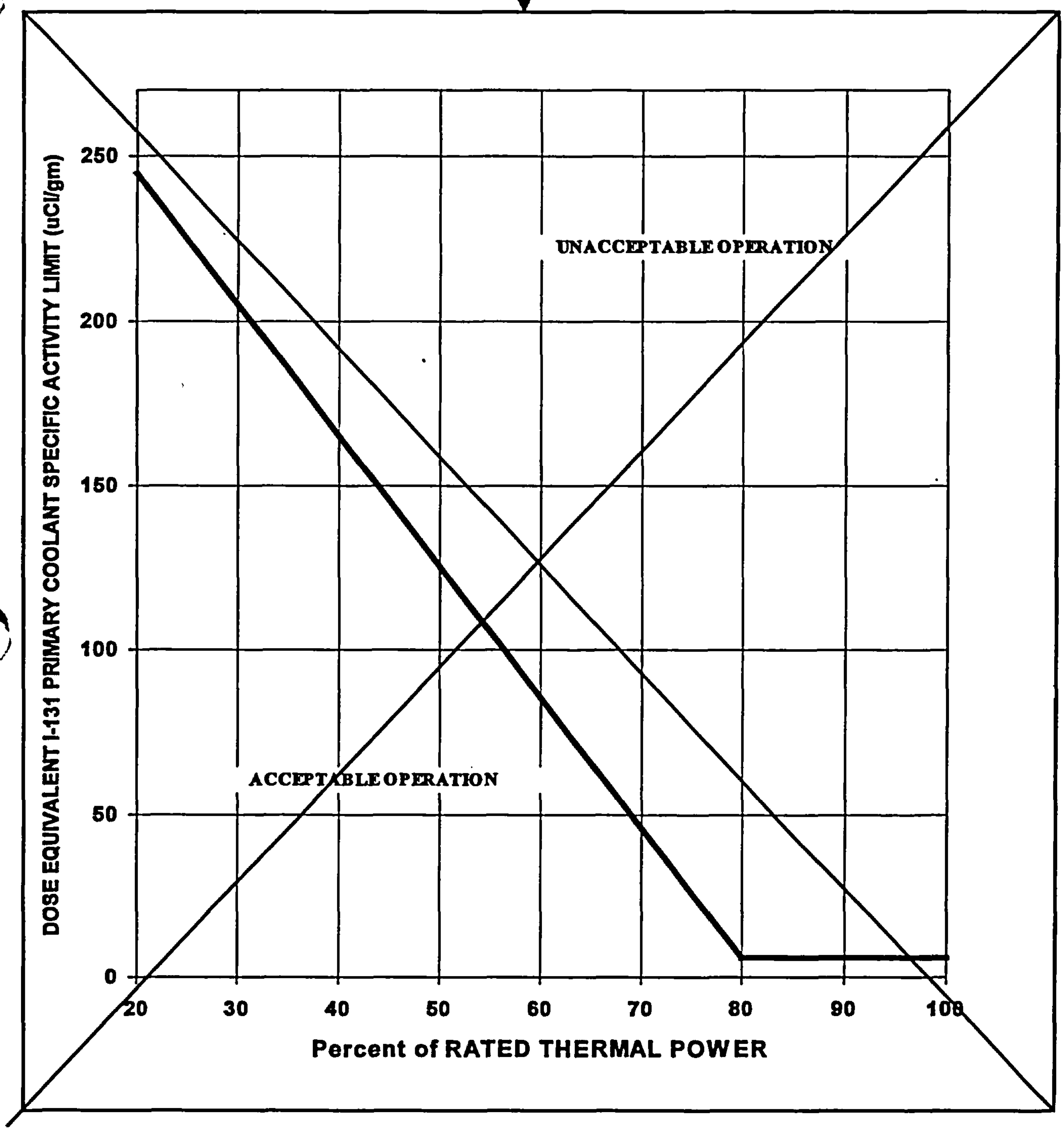
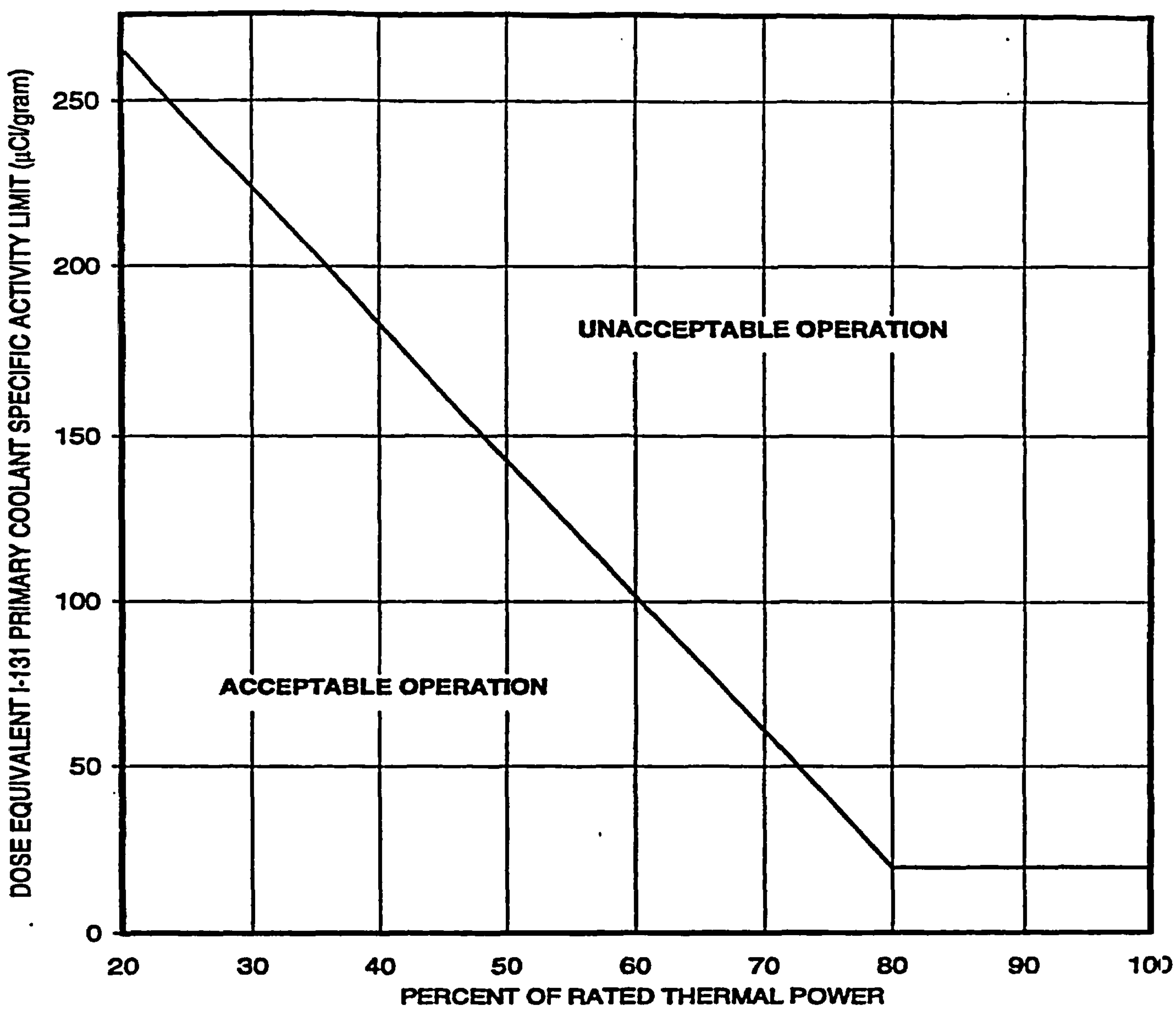


FIGURE 3.4-1
DOSE EQUIVALENT I-131 Primary Coolant Specific Activity Limit
Versus Percent of RATED THERMAL POWER with the Primary
Coolant Specific Activity > ~~0.10~~0.35 µCi/gram DOSE EQUIVALENT I-131

Insert A1-1.


DOSE EQUIVALENT I-131 PRIMARY COOLANT SPECIFIC ACTIVITY LIMIT (µCi/gram)
250
200
150
100
50
0
UNACCEPTABLE OPERATION
ACCEPTABLE OPERATION
20
30
40
50
60
70
80
90
100
PERCENT OF RATED THERMAL POWER

3/4.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3/4.5.1 ACCUMULATORS

LIMITING CONDITION FOR OPERATION

3.5.1 Each reactor coolant system accumulator shall be OPERABLE with:

a. The isolation valve open,

b. Between ~~7664~~ 6681 gallons (0% indicated level) and ~~7816~~ 7645 gallons (100% indicated level) of borated water,

c. Between 2300 and 2600 ppm of boron, and

d. A nitrogen cover-pressure of between ~~605~~ 561 and ~~661~~ 685 psig.

APPLICABILITY: MODES 1, 2 and 3.*

ACTION:

a. With one accumulator inoperable due to boron concentration not within limits, restore the inoperable accumulator to OPERABLE status within 72 hours.

b. With one accumulator inoperable for reasons other than Action a, restore the inoperable accumulator to OPERABLE status within 24 hours.

c. With either Action a or b not being completed within the specified completion time, be in at least HOT STANDBY within the next 6 hours and reduce pressurizer pressure to ≤ 1000 psig within 12 hours.

SURVEILLANCE REQUIREMENTS

4.5.1 Each accumulator shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1. Verifying the ~~contained~~ usable borated water volume and nitrogen cover-pressure in the tanks are within limits, and

2. Verifying that each accumulator isolation valve is open.

---

* Pressurizer Pressure above 1000 psig.

This page includes changes proposed by LAR 326.

3/4.5.2 ECCS SUBSYSTEMS - $T_{avg} \geq 350°F$

LIMITING CONDITION FOR OPERATION

3.5.2[(1)(2)] Two separate and independent ECCS subsystems shall be OPERABLE with each subsystem comprised of:

a. One OPERABLE centrifugal charging pump,

b. One OPERABLE low head safety injection pump, and

c. An OPERABLE flow path capable of taking suction from the refueling water storage tank on a safety injection signal and transferring suction to the containment sump during the recirculation phase of operation.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With one ECCS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

b. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted in accordance with 10 CFR 50.4 within 30 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.

---

(1) In MODE 3, one of the required centrifugal charging pumps may be made incapable of injecting to support transition into or from the Applicability of Specification 3.4.9.3 for up to 4 hours or until the temperature of all RCS cold legs exceeds the OPPS enable temperature specified in the PTLR plus 25°F, whichever comes first.

(2) In MODE 3, the ECCS automatic HHSI flow path may be isolated to support transition into or from the Applicability of Specification 3.5.4 for up to 4 hours or until the temperature of all RCS cold legs exceeds the OPPS enable temperature specified in the PTLR plus 25°F, whichever comes first.

No change proposed. Included for information only.

4.5.2 Each ECCS subsystem shall be demonstrated OPERABLE:

a. At least once per 12 hours by verifying that the following valves are in the indicated positions with power to the valve operator control circuits disconnected by removal of the plug in the lock out circuit from each circuit:

Valve Number	Valve Function	Valve Position
MOV SI 890 A	LHSI to hot leg	CLOSED
MOV SI 890 B	LHSI to hot leg	CLOSED
MOV SI 890 C	LHSI to cold leg	OPEN
MOV SI 869 A	Ch Pmp to hot leg	CLOSED
MOV SI 869 B	Ch Pmp to hot leg	CLOSED

b. By verifying, at the frequency specified in the Inservice Testing Program, the following:

1. The centrifugal charging pump's developed head at the flow test point is greater than or equal to the required developed head as specified in the Inservice Testing Program and the ECCS Flow Analysis.

2. The low head safety injection pump's developed head at the flow test point is greater than or equal to the required developed head as specified in the Inservice Testing Program and the ECCS Flow Analysis.

No change proposed. Included for information only.

SURVEILLANCE REQUIREMENTS (Continued)

c. At least once per 31 days by:

1. Verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

2. Verifying that each ECCS subsystem is aligned to receive electrical power from separate OPERABLE emergency buses.

d. By visual inspection which verifies that no loose debris (rags, trash, clothing, etc) is present in the containment which could be transported to the containment sump and cause restriction of the pump suctions during LOCA conditions. This visual inspection shall be performed:

1. For all accessible areas of the containment prior to establishing containment integrity, and

2. Of the areas affected within containment at the completion of each containment entry when containment integrity is established.

e. At least once per 18 months by:

1. A visual inspection of the containment sump and verifying that the subsystem suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or corrosion.

f. At least once per 18 months, during shutdown, by:

1. Cycling each power operated (excluding automatic) valve in the flow path that is not testable during plant operation, through at least one complete cycle of full travel.

2. Verifying that each automatic valve in the flow path actuates to its correct position on a safety injection signal.

3. Verifying that the centrifugal charging pump and low head safety injection pumps start automatically upon receipt of a safety injection signal.

This page includes changes proposed by LARs 321 and 326.

3/4.5.3 ECCS SUBSYSTEMS - T_{avg} < 350°F

LIMITING CONDITION FOR OPERATION

3.5.3 As a minimum, one ECCS subsystem comprised of the following shall be OPERABLE:

a. One OPERABLE centrifugal charging pump,

b. One OPERABLE Low Head Safety Injection Pump, and

c. An OPERABLE flow path capable of taking suction from the refueling water storage tank upon being manually realigned and transferring suction to the containment sump during the recirculation phase of operation.

APPLICABILITY: MODE 4.

ACTION:

- - - - - - - - - - - - - - - - - - GENERAL NOTE - - - - - - - - - - - - - - - -
Specification 3.0.4.b is not applicable to ECCS centrifugal charging pumps.
- -

a. With no ECCS subsystem OPERABLE because of the inoperability of either the centrifugal charging pump or the flow path from the refueling water storage tank, restore at least one ECCS subsystem to OPERABLE status within 1 hour or be in COLD SHUTDOWN within the next 20 hours.

b. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted in accordance with 10 CFR 50.4 within 30 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.

SURVEILLANCE REQUIREMENTS

4.5.3.1 The ECCS subsystem shall be demonstrated OPERABLE ~~per the applicable~~ by the performance of each of the Surveillance Requirements of 4.5.2 except for requirements 4.5.2.c, 4.5.2.f.2 and 4.5.2.f.3.

~~3/4.5.4 BORON INJECTION SYSTEM - BORON INJECTION TANK ≥ 350°F~~

~~LIMITING CONDITION FOR OPERATION~~

~~3.5.4.1.1 The boron injection tank shall be OPERABLE with:~~

~~* a. A minimum contained volume of 900 gallons of borated water,~~

~~+* b. Between 2400 and 2600 ppm of boron.~~

~~* 1 hour deviation is permitted to correct the out of specification condition.~~

~~+ To permit adequate recirculation and sampling following actions taken to correct the boron concentration, 4 hours is allowed for verification of the sample results providing corrective action was taken within the first hour.~~

~~APPLICABILITY: MODES 1, 2, 3.~~

~~ACTION:~~

~~With the boron injection tank inoperable, be in HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to 1% Δk/k at 200°F within the next 6 hours; restore the tank to OPERABLE status within the next 7 days or be in HOT SHUTDOWN within the next 12 hours.~~

~~SURVEILLANCE REQUIREMENTS~~

~~4.5.4.1.1 The boron injection tank shall be demonstrated OPERABLE by:~~

~~a. Verifying the water level in the surge tank at least once per 7 days.~~

~~b. Verifying the boron concentration of the water in the surge tank at least once per 7 days.~~

3/4.5.4 ~~BORON INJECTION SYSTEM~~

~~BORON INJECTION TANK < 350°F~~HHSI FLOW PATH

LIMITING CONDITION FOR OPERATION

3.5.4~~.1.2~~ The ~~boron injection tank~~ECCS automatic high head safety injection (HHSI) flow path shall be isolated. ~~and power removed from the inlet or outlet valves.~~

~~APPLICABILITY: When the temperature of one or more of the non-isolated RCS cold legs is ≤ the enable temperature specified in the PTLR.~~

APPLICABILITY: MODE 4 when any RCS cold leg temperature is less than or equal to the enable temperature specified in the PTLR.
MODE 5.
MODE 6 when the reactor vessel head is on.

ACTION:

With the ECCS automatic HHSI flow path ~~boron injection tank~~ not isolated, isolate the ~~tank~~ flow path within 1 hour. ~~and remove power from the inlet or outlet valves.~~

SURVEILLANCE REQUIREMENTS

4.5.4~~.1.2~~ The ECCS automatic HHSI ~~boron injection tank~~ flow path shall be verified isolated ~~by verifying~~ at least once per 7 days ~~that the Boron Injection Tank inlet or outlet valves are closed and de-energized~~ except for purposes of flow testing or valve stroke testing.

3/4.5.5 SEAL INJECTION FLOW

LIMITING CONDITION FOR OPERATION

3.5.5 Reactor coolant pump seal injection flow shall be less than or equal to 28 gpm with the charging pump discharge pressure greater than or equal to ~~2397~~2457 psig and the seal injection flow control valve full open.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With the seal injection flow not within the limit, adjust manual seal injection throttle valves to give a flow within the limit with the charging pump discharge pressure greater than or equal to ~~2397~~2457 psig and the seal injection flow control valve full open within 4 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 12 hours.

SURVEILLANCE REQUIREMENTS

4.5.5 Verify at least once per 31 days that the valves are adjusted to give a flow within the limit with the charging pump discharge at greater than or equal to ~~2397~~2457 psig and the seal injection flow control valve full open.[1]

(1) Not required to be performed until 4 hours after the Reactor Coolant System pressure stabilizes at greater than or equal to ~~2210~~ 2215 psig and less than or equal to ~~2250~~ 2255 psig.

This page includes changes proposed by LAR 321.

3/4.7 PLANT SYSTEMS

3/4.7.1 TURBINE CYCLE

MAIN STEAM SAFETY VALVES (MSSVs)

LIMITING CONDITION FOR OPERATION

3.7.1.1 Five MSSVs per steam generator shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

- - - - - - - - - - - - - - - GENERAL NOTE - - - - - - - - - - - - - - - -

Separate ACTION entry is allowed for each MSSV.

- -

a. With one or more steam generators with one MSSV inoperable and the Moderator Temperature Coefficient (MTC) zero or negative at all power levels, within 4 hours reduce THERMAL POWER to less than or equal to ~~61~~57% RTP; otherwise, be in HOT STANDBY within the next 6 hours, and in HOT SHUTDOWN within the next 6 hours.

b. With one or more steam generators with two or more MSSVs inoperable, or with one or more steam generators with one MSSV inoperable and the MTC positive at any power level, within 4 hours reduce THERMAL POWER to less than or equal to the Maximum Allowable % RTP specified in Table 3.7-1 for the number of OPERABLE MSSVs, and reduce the Power Range Neutron Flux-High reactor trip setpoint to less than or equal to the Maximum Allowable % RTP specified in Table 3.7-1 for the number of OPERABLE MSSVs within the next 32 hours[1]; otherwise, be in HOT STANDBY within the next 6 hours, and in HOT SHUTDOWN within the next 6 hours.

c. With one or more steam generators with four or more MSSVs inoperable, within 6 hours be in HOT STANDBY and in HOT SHUTDOWN within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.1 Verify[2] each required MSSV lift setpoint per Table 3.7-2 in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1 percent.

---

(1) Required to be performed only in MODE 1.
(2) Required to be performed only in MODES 1 and 2.

TABLE 3.7-1

OPERABLE Main Steam Safety Valves versus
Maximum Allowable Power

NUMBER OF OPERABLE MSSVs PER STEAM GENERATOR	MAXIMUM ALLOWABLE POWER (% RTP)
4	≤ ~~58~~50
3	≤ ~~41~~34
2	≤ ~~24~~19

TABLE 3.7-2

STEAM LINE SAFETY VALVES PER LOOP

	VALVE NUMBER	LIFT SETTING*** ~~(+1% -3%)~~	LIFT SETTING TOLERANCES	ORIFICE DIAMETER
a.	SV-MS101A, B & C	1075 psig	±1%/-3%	4.250 in.
b.	SV-MS102A, B & C	1085 psig	±3%	4.515 in.
c.	SV-MS103A, B & C	1095 psig	±3%	4.515 in.
d.	SV-MS104A, B & C	1110 psig	±3%	4.515 in.
e.	SV-MS105A, B & C	1125 psig	±3%	4.515 in.

*** The Lift Setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

PLANT SYSTEMS

PRIMARY PLANT DEMINERALIZED WATER (PPDW)

LIMITING CONDITION FOR OPERATION

3.7.1.3 The primary plant demineralized water storage tank shall be OPERABLE with a minimum ~~contained~~ usable volume of ~~140,000~~130,000 gallons.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With ~~less than 140,000 gallons of water in~~ the PPDW storage tank water volume not within the limit, within 4 hours either:

a. Restore the water volume to within the limit or be in HOT SHUTDOWN within the next 12 hours, or

b. Demonstrate the OPERABILITY of the reactor plant river water system as a backup supply to the auxiliary feedwater pumps and restore the PPDW storage tank water volume to within its limit within 7 days or be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.3 The PPDW storage tank shall be demonstrated OPERABLE at least once per 12 hours by verifying the water level.

ACTIVITY

LIMITING CONDITION FOR OPERATION

3.7.1.4 The specific activity of the secondary coolant system shall be ≤ ~~0.05~~0.10 µCi/gram DOSE EQUIVALENT I-131.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With the specific activity of the secondary coolant system > 0.~~05~~10 µCi/gram DOSE EQUIVALENT I-131, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.4 The specific activity of the secondary coolant system shall be determined to be within the limit by performance of the sampling and analysis program of Table 4.7-2.

This page includes changes proposed by LAR 310.

This page includes changes proposed by LAR 318.

CORE OPERATING LIMITS REPORT (Continued)

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

WCAP-9272-P-A, "WESTINGHOUSE RELOAD SAFETY EVALUATION METHODOLOGY," July 1985 (Westinghouse Proprietary).

WCAP-8745-P-A, Design Bases for the Thermal Overtemperature ΔT and Thermal Overpower ΔT trip functions, September 1986.

WCAP_12945-P-A, Volume 1 (Revision 2) and Volumes 2 through 5 (Revision 1), "Code Qualification Document for Best Estimate LOCA Analysis," March 1998 (Westinghouse Proprietary).

WCAP-10216-P-A, Revision 1A, "Relaxation of Constant Axial Offset Control FQ Surveillance Technical Specification," February 1994.

WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis", October 1999.

WCAP-12610-P-A, "VANTAGE+ Fuel Assembly Reference Core Report," April 1995 (Westinghouse Proprietary).

WCAP-15025-P-A, "Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids," April 1999.

As described in reference documents listed above, when an initial assumed power level of 102% of rated thermal power is specified in a previously approved method, 100.6% of rated thermal power may be used when input for reactor thermal power measurement of feedwater flow is by the leading edge flow meter (LEFM).

Caldon, Inc. Engineering Report-80P, "Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the LEFM√™ System," Revision 0, March 1997.

Attachment A-2

Beaver Valley Power Station, Unit No. 2
Proposed Technical Specification Changes

License Amendment Request No. 173

The following is a list of the affected pages:

Page	Pending LAR
License Page 3a	
1-1	
2-1	
3/4 1-15	
3/4 3-2	
3/4 3-10	
3/4 4-9	177
3/4 4-14a	
3/4 4-14b	
3/4 5-1	
3/4 5-7	
3/4 7-1	193
3/4 7-2	
3/4 7-3	
3/4 7-6	
6-20	182 & 191

transactions shall have no effect on the license for the BVPS Unit 2 facility throughout the term of the license.

(b) Further, the licensees are also required to notify the NRC in writing prior to any change in: (i) the term or conditions of any lease agreements executed as part of these transactions; (ii) the BVPS Operating Agreement, (iii) the existing property insurance coverage for BVPS Unit 2, and (iv) any action by a lessor or others that may have adverse effect on the safe operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations set forth in 10 CFR Chapter 1 and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

FENOC is authorized to operate the facility at a steady state reactor core power level of ~~2689~~ 2900 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 122, and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto are hereby incorporated in the license. FENOC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

1.0 DEFINITIONS

DEFINED TERMS

1.1 The DEFINED TERMS of this section appear in capitalized type and are applicable throughout these Technical Specifications.

THERMAL POWER

1.2 THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

RATED THERMAL POWER

1.3 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant ~~of 2689~~ as specified in the Licensing Requirements Manual, and shall not exceed 2900 MWt.

OPERATIONAL MODE

1.4 An OPERATIONAL MODE shall correspond to any one inclusive combination of core reactivity condition, power level, and average reactor coolant temperature specified in Table 1.1.

ACTION

1.5 ACTION shall be those additional requirements specified as corollary statements to each principal specification and shall be part of the specifications.

OPERABLE - OPERABILITY

1.6 A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s). Implicit in this definition shall be the assumption that all necessary attendant instrumentation, controls, normal and emergency electric power sources, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related safety function(s).

REPORTABLE EVENT

1.7 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

CONTAINMENT INTEGRITY

1.8 CONTAINMENT INTEGRITY shall exist when:

1.8.1 All penetrations required to be closed during accident conditions are either:

a. Capable of being closed by an OPERABLE containment automatic isolation valve system, or

2.0 SAFETY LIMITS

2.1 SAFETY LIMITS

REACTOR CORE

2.1.1 The combination of THERMAL POWER, pressurizer pressure, and the highest operating loop coolant temperature (T_{avg}) shall not exceed the limits specified in the COLR; and the following Safety Limits shall not be exceeded:

2.1.1.1 The departure from nucleate boiling ratio (DNBR) shall be maintained ≥ 1.17 for WRB-1 DNB correlation for Vantage 5H (V5H) fuel assemblies, and ≥ 1.14 for WRB-2M DNB correlation for Robust Fuel Assemblies (RFA).

2.1.1.2 The peak fuel centerline temperature shall be maintained ≤ 4700°F.

APPLICABILITY: MODES 1 and 2.

ACTION:

If Safety Limit 2.1.1 is violated, restore compliance and be in HOT STANDBY within 1 hour.

REACTOR COOLANT SYSTEM PRESSURE

2.1.2 The Reactor Coolant System pressure shall not exceed 2735 psig.

APPLICABILITY: MODES 1, 2, 3, 4, and 5.

ACTION:

MODES 1 and 2

Whenever the Reactor Coolant System pressure has exceeded 2735 psig, be in HOT STANDBY with the Reactor Coolant System pressure within its limit within 1 hour.

MODES 3, 4, and 5

Whenever the Reactor Coolant System pressure has exceeded 2735 psig, reduce the Reactor Coolant System pressure to within its limit within 5 minutes.

Refueling Water Storage Tank (RWST)

LIMITING CONDITION FOR OPERATION

3.1.2.8 The RWST shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 & 4.

ACTION:

With the refueling water storage tank inoperable, restore the tank to OPERABLE status within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.8 The RWST shall be verified OPERABLE:

a. At least once per 7 days by:

1. Verifying the boron concentration is between 2400 and 2600 ppm, and

2. Verifying a minimum usable volume of 859,248 gallons.

b. At least once per 24 hours by verifying the RWST solution temperature is ≥ 45°F and ≤ ~~50~~65°F when the RWST ambient air temperature is ~~> 50°F or < 45°F~~< 45°F or > 65°F.

(Next page is 3/4 1-17)

TABLE 3.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION

	FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	ALLOWABLE VALUE	APPLICABLE MODES	ACTION
1.	Manual Reactor Trip	2	1	2	N.A.	1, 2, 3(3), 4(3), and 5(3)	12
2.	Power Range, Neutron Flux						
	a. High Setpoint	4	2	3	≤ 109.5% of RTP*	1, 2	2
	b. Low Setpoint	4	2	3	≤ 25.5% OF RTP*	1(1), 2	2
3.	Power Range, Neutron Flux High Positive Rate	4	2	3	≤ 5.5% of RTP* with a time constant ≥ 2 seconds	1, 2	2
4.	~~Power Range, Neutron Flux High Negative Rate~~DELETED	~~4~~	~~2~~	~~3~~	~~≤ 5.5% of RTP* with a time constant ≥ 2 seconds~~	~~1, 2~~	~~2~~
5.	Intermediate Range, Neutron Flux	2	1	2	≤ 27.9% of RTP*	1(1), 2, 3(3), 4(3), and 5(3),	3
6.	Source Range(8), Neutron Flux						
	a. With Rod Withdrawal Capability	2	1	2	≤ 1.3 x 10^5 cps	2(2), 3(3), 4(3), and 5(3)	4
	b. With All Rods Fully Inserted and Without Rod Withdrawal Capability	2	0	1	N.A.	3(9), 4(9), and 5(9)	5

* = RATED THERMAL POWER

(8) Alternate detectors may only be used for monitoring purposes Without Rod Withdrawal Capability until detector functions are modified to permit equivalent alarm and trip functions.

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

Functional Unit	Channel Check	Channel Calibration	Channel Functional Test	Modes in Which Surveillance Required
1. Manual Reactor Trip	N.A.	N.A.	S/U(1), R(10)	1, 2, 3(14), 4(14), 5(14)
2. Power Range, Neutron Flux				
a. High Setpoint	S	D(2), M(3) and Q(6)	Q	1, 2
b. Low Setpoint	S	R(6)	S/U(1)	1(7), 2
3. Power Range, Neutron Flux, High Positive Rate	N.A.	R(6)	Q	1, 2
4. ~~Power Range, Neutron Flux, High Negative Rate~~DELETED	~~N.A.~~	~~R(6)~~	~~Q~~	~~1, 2~~
5. Intermediate Range, Neutron Flux	S	R(6)	S/U(1)	1, 2, 3(14), 4(14), 5(14)
6. Source Range(15), Neutron Flux				
a. With Rod Withdrawal Capability	S	R(6)	Q(8)	2, 3(14), 4(14) and 5(14)
b. With All Rods Inserted and Without Rod Withdrawal Capability	S	R(6)	Q(8)	3, 4 and 5
7. Overtemperature ΔT	S	R(6)	Q	1, 2
8. Overpower ΔT	S	R	Q	1, 2
9. Pressurizer Pressure-Low (Above P-7)	S	R	Q	1, 2
10. Pressurizer Pressure-High	S	R	Q	1, 2
11. Pressurizer Water Level-High (Above P-7)	S	R	Q	1, 2

This page includes changes proposed by LAR 177.

3/4.4.3 SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.4.3 All pressurizer code safety valves shall be OPERABLE with a lift setting* of 2485 psig + ~~1~~1.6% - 3%.**

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with all RCS cold leg temperatures > the enable temperature specified in the PTLR.

ACTION:

a. With one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in HOT SHUTDOWN with any RCS cold leg temperature ≤ the enable temperature specified in the PTLR and apply RCS overpressure protection requirements in accordance with Specification 3.4.9.3 within 12 hours.

b. After any pressurizer code safety valve lift, as indicated by the safety valve position indicator, involving loop seal or water discharge; be in at least HOT STANDBY within the next 6 hours, and in HOT SHUTDOWN with any RCS cold leg temperature ≤ the enable temperature specified in the PTLR and apply RCS overpressure protection requirements in accordance with Specification 3.4.9.3 within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.3 No additional requirements other than those required by Specification 4.0.5.

* The lift setting shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

** Within ± 1% following pressurizer code safety valve testing.

SURVEILLANCE REQUIREMENTS (Continued)

4. Percent Degradation means the percentage of the tube or sleeve wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the plugging or repair limit. A tube containing a defect is defective. Any tube which does not permit the passage of the eddy-current inspection probe shall be deemed a defective tube.

6. Plugging or Repair Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging or repaired by sleeving in the affected area because it may become unserviceable prior to the next inspection. The plugging or repair limit imperfection depths are specified in percentage of nominal wall thickness as follows:

   a) Original tube wall 40%

      This definition does not apply to tube support plate intersections for which the voltage-based repair criteria are being applied. Refer to 4.4.5.4.a.10 for the repair limit applicable to these intersections.

   b) ABB Combustion Engineering TIG welded sleeve wall ~~32~~27%

   c) Westinghouse laser welded sleeve wall 25%

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steamline or feedwater line break as specified in 4.4.5.3.c, above.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot-leg side) completely around the U-bend to the top support to the cold-leg.

9. Tube Repair refers to sleeving which is used to maintain a tube in-service or return a tube to service. This includes the removal of plugs that were installed as a corrective or preventive measure. The following sleeve designs have been found acceptable:

    a) ABB Combustion Engineering TIG welded sleeves, CEN-629-P, Revision 02 and CEN-629-P Addendum 1.

    b) Westinghouse laser welded sleeves, WCAP-13483, Revision ~~1~~2.

10. Tube Support Plate Plugging Limit is used for the disposition of an alloy 600 steam generator tube for continued service that is experiencing predominantly axially oriented outside diameter stress corrosion cracking confined within the thickness of the tube support plates. At tube support plate intersections, the plugging (repair) limit is based on maintaining steam generator tube serviceability as described below:

    a) Steam generator tubes, whose degradation is attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with bobbin voltages less than or equal to 2.0 volts will be allowed to remain in service.

    b) Steam generator tubes, whose degradation is attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with a bobbin voltage greater than 2.0 volts will be repaired or plugged, except as noted in 4.4.5.4.a.10.c below.

3/4.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

ACCUMULATORS

LIMITING CONDITION FOR OPERATION

3.5.1 Each Reactor Coolant System accumulator shall be OPERABLE with:

a. The isolation valve open,

b. Between ~~7532~~ 6898 gallons (0% indicated level) and ~~7802~~ 8019 gallons (100% indicated level) of borated water,

c. Between 2300 and 2600 ppm of boron, and

d. A nitrogen cover-pressure of between ~~585~~ 561 and ~~665~~ 685 psig.

APPLICABILITY: MODES 1, 2 and 3.*

ACTION:

a. With one accumulator inoperable due to boron concentration not within limits, restore the inoperable accumulator to OPERABLE status within 72 hours.

b. With one accumulator inoperable for reasons other than Action a, restore the inoperable accumulator to OPERABLE status within 24 hours.

c. With either Action a or b not being completed within the specified completion time, be in at least HOT STANDBY within the next 6 hours and reduce pressurizer pressure to ≤ 1000 psig within 12 hours.

SURVEILLANCE REQUIREMENTS

4.5.1 Each accumulator shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1. Verifying the ~~contained~~ usable borated water volume and nitrogen cover-pressure in the tanks are within limits, and

2. Verifying that each accumulator isolation valve is open.

*Pressurizer Pressure above 1000 psig.

3/4.5.4 SEAL INJECTION FLOW

LIMITING CONDITION FOR OPERATION

3.5.4 Reactor coolant pump seal injection flow shall be less than or equal to 28 gpm with the charging pump discharge pressure greater than or equal to ~~2410~~2457 psig and the seal injection flow control valve full open.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With the seal injection flow not within the limit, adjust manual seal injection throttle valves to give a flow within the limit with the charging pump discharge pressure greater than or equal to ~~2410~~2457 psig and the seal injection flow control valve full open within 4 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 12 hours.

SURVEILLANCE REQUIREMENTS

4.5.4 Verify at least once per 31 days that the valves are adjusted to give a flow within the limit with the charging pump discharge at greater than or equal to ~~2410~~2457 psig and the seal injection flow control valve full open.(1)

---

(1) Not required to be performed until 4 hours after the Reactor Coolant System pressure stabilizes at greater than or equal to 2215 psig and less than or equal to 2255 psig.

This page includes changes proposed by LAR 193.

3/4.7 PLANT SYSTEMS

3/4.7.1 TURBINE CYCLE

MAIN STEAM SAFETY VALVES (MSSVs)

LIMITING CONDITION FOR OPERATION

3.7.1.1 Five MSSVs per steam generator shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

\- - - - - - - - - - - - - - - - GENERAL NOTE - - - - - - - - - - - - - - - -

Separate ACTION entry is allowed for each MSSV.

\- -

a. With one or more steam generators with one MSSV inoperable and the Moderator Temperature Coefficient (MTC) zero or negative at all power levels, within 4 hours reduce THERMAL POWER to less than or equal to ~~61~~57% RTP; otherwise, be in HOT STANDBY within the next 6 hours, and in HOT SHUTDOWN within the next 6 hours.

b. With one or more steam generators with two or more MSSVs inoperable, or with one or more steam generators with one MSSV inoperable and the MTC positive at any power level, within 4 hours reduce THERMAL POWER to less than or equal to the Maximum Allowable % RTP specified in Table 3.7-1 for the number of OPERABLE MSSVs, and reduce the Power Range Neutron Flux-High reactor trip setpoint to less than or equal to the Maximum Allowable % RTP specified in Table 3.7-1 for the number of OPERABLE MSSVs within the next 32 hours[1]; otherwise, be in HOT STANDBY within the next 6 hours, and in HOT SHUTDOWN within the next 6 hours.

c. With one or more steam generators with four or more MSSVs inoperable, within 6 hours be in HOT STANDBY and in HOT SHUTDOWN within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.1 Verify[2] each required MSSV lift setpoint per Table 3.7-2 in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1 percent.

(1) Required to be performed only in MODE 1.
(2) Required to be performed only in MODES 1 and 2.

TABLE 3.7-1

OPERABLE Main Steam Safety Valves versus
Maximum Allowable Power

NUMBER OF OPERABLE MSSVs PER STEAM GENERATOR	MAXIMUM ALLOWABLE POWER (% RTP)
4	≤ ~~58~~50
3	≤ ~~41~~34
2	≤ ~~24~~19

TABLE 3.7-2

STEAM LINE SAFETY VALVES PER LOOP

	VALVE NUMBER	LIFT SETTING* ~~(+1% -3%)~~	LIFT SETTING TOLERANCES	ORIFICE DIAMETER
a.	2MSS-SV101A, B & C	1075 psig	±1%/-3%	4.515 in.
b.	2MSS-SV102A, B & C	1085 psig	±3%	4.515 in.
c.	2MSS-SV103A, B & C	1095 psig	±3%	4.515 in.
d.	2MSS-SV104A, B & C	1110 psig	±3%	4.515 in.
e.	2MSS-SV105A, B & C	1125 psig	±3%	4.515 in.

* The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

PLANT SYSTEMS

PRIMARY PLANT DEMINERALIZED WATER (PPDW)

LIMITING CONDITION FOR OPERATION

3.7.1.3 The primary plant demineralized water storage tank shall be OPERABLE with a minimum usable volume of ~~127,500~~130,000 gallons.~~(1)~~

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With the PPDW storage tank water volume not within the limit, within 4 hours either:

a. Restore the water volume to within the limit or be in HOT SHUTDOWN within the next 12 hours, or

b. Demonstrate the OPERABILITY of the service water system as a backup supply to the auxiliary feedwater pumps and restore the PPDW storage tank water volume to within its limit within 7 days or be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.3 The PPDW storage tank shall be demonstrated OPERABLE at least once per 12 hours by verifying the water level.

~~(1) The required volume is an analysis value. This value shall be appropriately increased to account for measurement uncertainties.~~

This page includes changes proposed by LAR 182.

This page includes changes proposed by LAR 191.

REPORTING REQUIREMENTS (Continued)

WCAP-8745-P-A, "Design Bases for the Thermal Overtemperature ΔT and Thermal Overpower ΔT Trip Functions," September 1986.

WCAP_12945-P-A, Volume 1 (Revision 2) and Volumes 2 through 5 (Revision 1), "Code Qualification Document for Best Estimate LOCA Analysis," March 1998 (Westinghouse Proprietary).

WCAP-10216-P-A, Revision 1A, "Relaxation of Constant Axial Offset Control FQ Surveillance Technical Specification," February 1994.

WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis", October 1999.

WCAP-12610-P-A, "VANTAGE+ Fuel Assembly Reference Core Report," April 1995 (Westinghouse Proprietary).

WCAP-15025-P-A, "Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids," April 1999.

As described in reference documents listed above, when an initial assumed power level of 102% of rated thermal power is specified in a previously approved method, 100.6% of rated thermal power may be used when input for reactor thermal power measurement of feedwater flow is by the leading edge flow meter (LEFM).

Caldon, Inc. Engineering Report-80P, "Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the LEFM√™ System," Revision 0, March 1997.

Caldon, Inc. Engineering Report-160P, "Supplement to Topical Report ER-80P: Basis for a Power Uprate With the LEFM√™ System," Revision 0, May 2000.

Attachment B-1

Beaver Valley Power Station, Unit No. 1

Proposed Technical Specification Bases Changes

License Amendment Request No. 302

The following is a list of the affected pages:

Page	Pending LAR
B 2-1	
B 3/4 1-1	
B 3/4 3-1c	
B 3/4 3-1d	
B 3/4 3-1f	
B 3/4 3-1h	310
B 3/4 4-2a	322
B 3/4 4-2b	
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B 3/4 4-3f	
B 3/4 4-4	321
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B 3/4 4-10a	326
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B 3/4 7-1f	321
B 3/4 7-2a	
B 3/4 7-2b	
B 3/4 7-2j	
B 3/4 7-5	

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 and therefore THERMAL POWER and Reactor Coolant Temperature and Pressure have been related to DNB through the WRB-1, WRB-2, WRB-2M, and W-3 correlations. ~~The WRB-1 DNB~~ These correlations ~~has~~have 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, defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, is indicative of the margin to DNB. The WRB-1 and WRB-2M DNB correlations are associated with transients that could impact the reactor core safety limits. These correlations, along with the WRB-2 and W-3 DNB correlations, are used in support of the licensing basis transient analyses.

The DNB thermal design criterion is that the probability of DNB not occurring on the most limiting rod is at least 95 percent at a 95 percent confidence level for any Condition I or II event.

In meeting the DNB design criterion with the Revised Thermal Design Procedure (RTDP), uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters and computer codes have been statistically combined with the DNB correlation uncertainties to determine the DNBR Design Limits which are ~~1.24 for typical and 1.23 for thimble cell~~1.23/1.22 (typical cell/thimble cell) for Vantage 5H (V5H) fuel assemblies, and 1.22/1.22 (typical cell/thimble cell) for Robust Fuel Assemblies (RFA). In addition, margin has been maintained in the design by meeting a safety analysis DNBR limit of 1.33 for typical cells and 1.32 for thimble cells for WRB-1, and 1.55 for typical and thimble cells for WRB-2M, in performing safety analyses.

The Standard Thermal Design Procedure (STDP) is used for those analyses where RTDP is not applicable. With this procedure, the nominal values with uncertainties are used to calculate DNBRs. The DNBR limits for STDP are the appropriate correlation limits increased by sufficient margin to offset the applicable DNBR penalties.

The figure provided in the COLR shows the loci of points of THERMAL POWER, Reactor Coolant System pressure and average temperature for which the minimum DNBR is no less than the safety analysis DNBR limit or the average enthalpy at the vessel exit is equal to the enthalpy of saturated liquid. The figure is based on enthalpy hot channel factor limits provided in the COLR.

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BASES

3/4.1.1 BORATION CONTROL

3.4.1.1.1 and 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. 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. In the analysis of this accident, a minimum SHUTDOWN MARGIN of 1.77% $\Delta k/k$ is initially required to control the reactivity transient. Accordingly, the SHUTDOWN MARGIN requirement is based upon this limiting condition and is consistent with FSAR accident analysis assumptions. With Tavg < 200°F, the reactivity transients resulting from a postulated steam line break cooldown are minimal and a 1% $\Delta k/k$ shutdown margin provides adequate protection.

The purpose of borating to the cold shutdown boron concentration prior to blocking safety injection is to preclude a return to criticality should a steam line break occur during plant heatup or cooldown.

3/4.1.1.3 BORON DILUTION

A minimum flow rate of at least 3000 GPM provides adequate mixing, prevents stratification and ensures that reactivity changes will be gradual during boron concentration reductions in the Reactor Coolant System. A flow rate of at least 3000 GPM will circulate ~~an equivalent~~the Reactor Coolant System volume ~~of 9370 cubic feet~~ in approximately 30 minutes. The reactivity change rate associated with boron reductions will therefore be within the capability for operator recognition and control.

3/4.1.1.4 MODERATOR TEMPERATURE COEFFICIENT (MTC)

The limitations on MTC are provided to ensure that the assumptions used in the accident and transient analyses remain valid through each

BASES

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

Manual Reactor Trip

The Manual Reactor Trip is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

Power Range, Neutron Flux

The Power Range, Neutron Flux channel high setpoint provides reactor core protection against reactivity excursions which are too rapid to be protected by temperature and pressure protective circuitry. The low set point provides redundant protection in the power range for a power excursion beginning from low power. The trip associated with the low setpoint may be manually bypassed when P-10 is active (two of the four power range channels indicate a power level of above the P-10 setpoint and is automatically reinstated when P-10 becomes inactive (three of the four channels indicate a power level below the P-10 setpoint).

Power Range, Neutron Flux, High Positive ~~Rates~~

The Power Range Positive Rate trip provides protection against rapid flux increases which are characteristic of rod ejection events from any power level. Specifically, this trip complements the Power Range Neutron Flux High and Low trips to ensure that the criteria are met for rod ejection from partial power.

~~The Power Range Negative Rate trip provides protection to ensure that the minimum DNBR is maintained above the design DNBR limit for control rod drop accidents. At high power a single or multiple rod drop accident could cause flux peaking which, when in conjunction with nuclear power being maintained equivalent to turbine power by action of the automatic rod control system, could cause an unconservative local DNBR to exist. The Power Range Negative Rate trip will prevent this from occurring by tripping the reactor. For those transients on which reactor trip on power range negative rate trip is not postulated, it is shown that the minimum DNBR is greater than the design DNBR limit.~~

Intermediate and Source Range, Nuclear Flux

The Intermediate and Source Range, Nuclear Flux trips provide reactor core protection during reactor start-up. 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 the trip setpoint unless manually blocked when P-6

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3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

becomes active. The Intermediate Range Channels will initiate a reactor trip at a current level proportional to the trip setpoint unless manually blocked when P-10 becomes active. No credit was 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.

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~~ (about 4 seconds)~~, and pressure is within the range between the High and Low Pressure reactor trips. This setpoint includes corrections for changes in density and heat capacity of water with temperature and dynamic compensation for piping delays from the core to the loop temperature detectors. 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 3.3-1.

Overpower ΔT

The Overpower ΔT reactor trip provides assurance of fuel integrity, e.g., no melting, under all possible overpower conditions, limits the required range for Overtemperature ΔT protection, and provides a backup to the High Neutron Flux trip. The setpoint includes corrections for changes in density and heat capacity of water with temperature, and dynamic compensation for piping delays from the core to the loop temperature detectors.~~ No credit was taken for operation of this trip in the accident analyses; however, its functional capability at the specified trip setting is required by this specification to enhance the overall reliability of the Reactor Protection System.~~

Pressurizer Pressure

The Pressurizer High and Low Pressure trips are provided to limit the pressure range in which reactor operation is permitted. The High Pressure trip is backed up by the pressurizer code safety valves for

BASES

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

Undervoltage and Underfrequency - Reactor Coolant Pump Busses

The Undervoltage and Underfrequency Reactor Coolant Pump bus trips provide reactor core protection against DNB as a result of loss of voltage or underfrequency to more than one reactor coolant pump. The trip setpoints assure a reactor trip signal is generated before the low flow trip set point is reached. Time delays are incorporated in the underfrequency and undervoltage trips to prevent spurious reactor trips from momentary electrical power transients. For undervoltage, the delay is set so that the time required for a signal to reach the reactor trip breakers following the simultaneous trip of two or more reactor coolant pump bus circuit breakers shall not exceed 0.9 seconds. For underfrequency, the delay is set so that the time required for a signal to reach the reactor trip breakers after the underfrequency trip set point is reached shall not exceed 0.3 seconds.

Turbine Trip

A Turbine Trip causes a direct reactor trip when operating above P-9. Each of the turbine trips provides turbine protection and reduces the severity of the ensuing transient. No credit was taken in the accident analyses for operation of these trips. Their functional capability at the specified trip settings is required to enhance the overall reliability of the Reactor Protection System.

Safety Injection Input from ESF

If a reactor trip has not already been generated by the reactor protective instrumentation, the ESF automatic actuation logic channels will initiate a reactor trip upon any signal which initiates a safety injection. This trip is provided to protect the core in the event of a LOCA and a steamline break (SLB). The ESF instrumentation channels which initiate a safety injection signal are shown in Table 3.3-3.

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This page includes changes associated with LAR 310.

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

OPERABILITY of the following trips in Table 3.3-1 provides additional diverse or anticipatory protection features and is not credited in the accident analyses:

Undervoltage - Reactor Coolant Pumps (Above P-7); Underfrequency Reactor Coolant Pumps (Above P-7); Turbine Trip (Above P-9); Reactor Coolant Pump Breaker Position Trip (Above P-7); Turbine First Stage Pressure, P-13.

Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and supplements to that report as approved by the NRC and documented in the SER (letter to J. J. Sheppard from Cecil O. Thomas dated February 21, 1985). Jumpers and lifted leads are not an acceptable method for placing equipment in bypass as documented in the NRC safety evaluation report for this WCAP.

The surveillance requirements for the Manual Trip Function, Reactor Trip Breakers and Reactor Trip Bypass Breakers are provided to reduce the possibility of an Anticipated Transient Without Scram (ATWS) event by ensuring OPERABILITY of the diverse trip features (Reference: Generic Letter 85-09).

Incore-Excore Calibration is the calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This surveillance is primarily performed to verify the AFD input to the Overtemperature ΔT function. The surveillance is required only if the reactor power is greater then 50% RTP and 7 days is allowed for performing the first surveillance after reaching 50% RTP following a refueling outage. Six hours are provided to allow state point stabilization. Otherwise, this surveillance is required on a quarterly basis.

The measurement of response time at the specified frequencies provides assurance that the protective and ESF action function associated with each channel is completed within the time limit assumed in the accident analyses. No credit was taken in the analyses for those channels with response times indicated as not applicable.

ESF response times which include sequential operation of the RWST and VCT valves are based on values assumed in the Non-LOCA safety analyses and are provided in Section 3 of the Licensing Requirements Manual. These analyses take credit for injection of borated water~~,~~ from the RWST. ~~Initial borated water is supplied by the BIT,~~

~~however, i~~Injection of borated water ~~from the RWST~~ is assumed not to occur until the VCT charging pump suction valves are closed following opening of the RWST charging pump suction valves. When sequential operation of the RWST and VCT valves is not included in the response times, the values specified are based on the LOCA analyses. The LOCA analyses take

3/4.4.5 STEAM GENERATORS (Continued)

operation would be limited by the limitation of steam generator tube leakage between the Primary Coolant System and the Secondary Coolant System (primary-to-secondary LEAKAGE = 150 gallons per day per steam generator). ~~Axial cracks having~~ Maintaining a primary-to-secondary LEAKAGE less than this limit helps to ensure~~during operation will have an~~ adequate margin ~~of safety~~ to withstand the loads imposed during normal operation and by postulated accidents. Operating plants have demonstrated that primary-to-secondary LEAKAGE of 150 gallons per day per steam generator can readily be detected. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged. ~~or repaired by sleeving. The technical bases for sleeving are described in the approved vendor reports listed in Surveillance Requirement 4.4.5.4.a.9.~~

Wastage-type defects are unlikely with ~~the all volatile treatment (AVT)~~ proper chemistry of secondary coolant, such as provided by All Volatile Treatment (AVT). However, even if a defect of similar type should develop in service, it will be found during scheduled inservice steam generator tube examinations. Plugging ~~or repair~~ will be required of all tubes with imperfections exceeding the plugging ~~or repair~~ limit. ~~Degraded steam generator tubes may be repaired by the installation of sleeves which span the degraded tube section. A steam generator tube with a sleeve installed meets the structural requirements of tubes which are not degraded, therefore, the sleeve is considered a part of the tube. The surveillance requirements identify those sleeving methodologies approved for use. Except for Alloy 800 sleeves, if an installed sleeve is found to have through wall penetration greater than or equal to the plugging limit, the tube must be plugged. The plugging limit for the sleeve is derived from R.G. 1.121 analysis which utilizes a 20 percent allowance for eddy current uncertainty in determining the depth of tube wall penetration and additional degradation growth.~~ Steam generator tube inspections of operating plants have demonstrated the capability to reliably detect ~~degradation~~ a wastage-type defect that has penetrated 20 percent of the original tube wall thickness. ~~All tubes with Alloy 800 sleeves will be plugged upon detection of any service induced imperfection, degradation or defect in the sleeve and/or the pressure boundary of the original tube wall in the sleeve/tube assembly (i.e., the sleeve-to-tube joint).~~

~~The voltage-based repair limits of these surveillance requirements (SR) implement the guidance in Generic Letter (GL) 95-05 and are applicable only to Westinghouse-designed steam generators (SGs) with outside diameter stress corrosion cracking (ODSCC) located at the tube-to-tube support plate intersections. The voltage-based repair limits are not applicable to other forms of SG tube degradation nor are they applicable to ODSCC that occurs at other locations within the SG. Additionally, the repair criteria apply only to indications where the degradation mechanism is dominantly axial ODSCC with~~

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~~BASES~~

~~3/4.4.5 STEAM GENERATORS (Continued)~~

~~no NDE detectable cracks extending outside the thickness of the support plate. Refer to GL 95-05 for additional description of the degradation morphology.~~

~~Implementation of these SRs requires a derivation of the voltage structural limit from the burst versus voltage empirical correlation and then the subsequent derivation of the voltage repair limit from the structural limit (which is then implemented by this surveillance).~~

~~The voltage structural limit is the voltage from the burst pressure/bobbin voltage correlation, at the 95 percent prediction interval curve reduced to account for the lower 95/95 percent tolerance bound for tubing material properties at 650°F (i.e., the 95 percent LTL curve). The voltage structural limit must be adjusted downward to account for potential degradation growth during an operating interval and to account for NDE uncertainty. The upper voltage repair limit,~~ $\cancel{V_{URL}}$~~, is determined from the structural voltage limit by applying the following equation:~~

$$\cancel{V_{URL} = V_{SL} - V_{Gr} - V_{NDE}}$$

~~where~~ $\cancel{V_{Gr}}$ ~~represents the allowance for degradation growth between inspections and~~ $\cancel{V_{NDE}}$ ~~represents the allowance for potential sources of error in the measurement of the bobbin coil voltage. Further discussion of the assumptions necessary to determine the voltage repair limit are discussed in GL 95-05.~~

~~Safety analyses were performed pursuant to Generic Letter 95-05 to determine the maximum MSLB induced primary to secondary leak rate that could occur without offsite doses exceeding a small fraction of 10 CFR 100 (concurrent iodine spike), 10 CFR 100 (pre-accident iodine spike), and without control room doses exceeding GDC-19. The current value of this allowable leak rate and a summary of the analyses are provided in Section 14.2.5 of the UFSAR.~~

~~The mid-cycle equation in SR 4.4.5.4.a.10.d should only be used during unplanned inspections in which eddy current data is acquired for indications at the tube support plates.~~

~~SR 4.4.5.5 implements several reporting requirements recommended by GL 95-05 for situations which the NRC wants to be notified prior to returning the SGs to service. For the purposes of this reporting requirement, leakage and conditional burst probability can be calculated based on the as-found voltage distribution rather than the projected end-of-cycle (EOC) voltage distribution (refer to GL 95-05~~

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~~BASES~~

This page includes changes associated with LAR 328.

~~3/4.4.5 STEAM GENERATORS (Continued)~~

~~for more information) when it is not practical to complete these calculations using the projected EOC voltage distributions prior to returning the SGs to service. Note that if leakage and conditional burst probability were calculated using the measured EOC voltage distribution for the purposes of addressing the GL section 6.a.1 and 6.a.3 reporting criteria, then the results of the projected EOC voltage distribution should be provided per the GL section 6.b (c) criteria.~~

~~The W* criteria incorporate the guidance provided in WCAP-14797, Revision 2, "Generic W* Tube Plugging Criteria for 51 Series Steam Generator Tubesheet Region WEXTEX Expansions." W* length is the undegraded length of tubing into the tubesheet below the bottom of the WEXTEX transition (BWT) that precludes tube pullout in the event of a complete circumferential separation of the tube below the W* length. W* distance is the undegraded distance from the top of the tubesheet to the bottom of the W* length including the distance from the top of the tubesheet to the BWT and measurement uncertainties. Indications detected within the W* distance or less than eight inches below the top of tube sheet (TTS), which ever is greater, will be repaired upon detection.~~

~~Tubes to which WCAP-14797 is applied can experience through wall degradation up to the limits defined in Revision 2 without increasing the probability of a tube rupture or large leakage event. Tube degradation of any type or extent below W* distance, including a complete circumferential separation of the tube, is acceptable. As applied at Beaver Valley Unit 1, the W* methodology is used to define the required tube inspection depth into the hot leg tubesheet, and is not used to permit degradation in the W* distance to remain in service. Thus while primary to secondary leakage in the W* distance need not be postulated, primary to secondary leakage from potential degradation below the W* distance will be assumed for every inservice tube in the bounding steam generator. The postulated leakage during a steam line break for Cycle 17 shall be equal to the following equation (as described in LAR 1A-328, Section 4.3.6):~~

~~Postulated SLB Leakage~~ $_{\text{cycle 17}}$ ~~= ARC~~ $_{\text{GL 95-05}}$ ~~+ Assumed Leakage~~ $_{\text{0"-8" TTS}}$

~~+ Assumed Leakage~~ $_{\text{8"-12" TTS}}$ ~~+ Assumed Leakage~~ $_{\text{>12" TTS}}$

~~Where: ARC~~ $_{\text{GL 95-05}}$ ~~is the normal SLB leakage derived from alternate repair criteria methods and the 1R16 steam generator tube inspections. This term would also include any other postulated leakage (e.g., as committed in LAR 1A-322 for Alloy 800 sleeves).~~

~~Assumed Leakage~~ $_{\text{0"-8" TTS}}$ ~~is the postulated leakage for undetected indications in steam generator tubes left in service between 0 inches and 8 inches below the top of the tubesheet.~~

~~Assumed Leakage $_{8-12''-TTS}$ is the conservatively assumed leakage from the total of identified and postulated unidentified indications in steam generator tubes left in service between 8 and 12 inches below the top of the tubesheet. This is 0.0045 gpm times number of indications. All postulated unidentified indications will be conservatively assumed to be in one steam generator. The highest number of identified indications left in service between 8 and 12 inches below TTS in any one steam generator will be included in this term.~~

~~Assumed Leakage $_{<12''-TTS}$ is the conservatively assumed leakage for the bounding steam generator tubes left in service below 12 inches below the top of the tubesheet. This is 0.00009 gpm times number of tubes left in service in the least plugged steam generator following 1R16.~~

~~The aggregate calculated SLB leakage from the application of all alternate repair criteria and the above assumed leakage shall be reported to the NRC in accordance with applicable Technical Specifications.~~

~~The combined calculated leak rate from all alternate repair criteria must be less than the maximum allowable steam line break leak rate limit in any one steam generator in order to maintain doses within 10 CFR 100 guideline values and within GDC-19 values during a postulated steam line break event.~~

Whenever the results of any steam generator tubing inservice inspection fall into Category C-3, these results will be reported to the Commission pursuant to Specification 6.6 prior to resumption of plant operation. Such cases will be considered by the Commission on a case-by-case basis and may result in a requirement for analysis, laboratory examinations, tests, additional eddy-current inspection, and revision of the Technical Specifications, if necessary.

This page includes changes associated with LAR 328.

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3/4.4.6.2 OPERATIONAL LEAKAGE (Continued)
APPLICABLE SAFETY ANALYSES (Continued)

affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere conservatively assumes a ~~10 gpm~~ 450 gpd primary-to-secondary LEAKAGE. ~~With the exception described below for the main steamline break (MSLB) analyzed in support of voltage-based steam generator tube repair criteria.~~

~~Primary-to-secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steamline break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.~~

~~The MSLB is more limiting for site radiation releases. The primary-to-secondary LEAKAGE assumed in the safety analysis for the MSLB accident is described in UFSAR Section 14.2.5. The radiological consequences of a MSLB outside of containment was reanalyzed in support of the tube support plate voltage-based repair criteria stated in SR 4.4.5.4.a.10. For this analysis, the thyroid dose was maximized at 10% of the 10 CFR Part 100 guideline of 300 rem for the co-incident iodine spike case. RCS leakage was based on projection rather than on technical specification leakage limits. The analysis indicated that offsite doses would remain within regulatory criteria with the assumed primary-to-secondary leakage (described in UFSAR Section 14.2.5) should steam generator tubes fail due to the depressurization associated with a MSLB.~~

~~A similar analysis was performed using a control room thyroid dose of 30 rem as the criterion. The control room was assumed to be manually isolated and pressurized at T=30 minutes for a period of one hour, at which time filtered emergency intake would be automatically started. The control room would be purged with fresh air at T=8 hours following release cessation. The analysis indicated that control room doses would remain within regulatory criteria with the assumed primary-to-secondary leakage (described in UFSAR Section 14.2.5) should steam generator tubes fail due to the depressurization associated with a MSLB.~~

Primary-to-secondary LEAKAGE is a factor in the dose assessment of accidents or transients that involve secondary steam release to the atmosphere, such as a main steam line break (MSLB), a locked rotor accident (LRA), a Loss of AC Power (LACP), a Control Rod Ejection Accident (CREA) and to a lesser extent, a Steam Generator Tube Rupture (SGTR). The leakage contaminates the secondary fluid. The limit on the primary-to-secondary leakage ensures that the dose contribution at the site boundary from tube leakage following such accidents are limited to appropriate fractions of the 10 CFR 50.67 limit of 25 Rem TEDE as allowable by Regulatory Guide 1.183. The limit on the primary-to-secondary leakage also ensures that the dose contribution from tube leakage in the control room is limited to the 10 CFR 50.67 limit of 5 Rem TEDE. Among all of the analyses that release primary side activity to the environment via tube leakage, the MSLB is of particular concern because the ruptured main steam line provides a pathway to release the primary to secondary leakage directly to the environment without dilution in the secondary fluid.

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

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This page includes changes associated with LAR 321.

3/4.4.7 (This Specification number is not used.)

3/4.4.8 SPECIFIC ACTIVITY

The primary coolant specific activity is limited in order to maintain offsite and control room operator doses associated with postulated accidents within applicable requirements. Specifically, the ~~0.10~~0.35 µCi/gm DOSE EQUIVALENT I-131 limit ensures that the offsite TEDE dose ~~does not exceed a small fraction of 10 CFR Part 100 guidelines~~ is limited to appropriate fractions of the 10 CFR 50.67 limit of 25 rem TEDE as allowable by Regulatory Guide 1.183 and that control room operator ~~thyroid~~ TEDE dose does not exceed ~~GDC 19~~the 10 CFR 50.67 guideline in the event of ~~primary to secondary leakage induced by~~ a steam generator tube rupture or a main steam line break.

Required Action "a" for MODES 1 , 2 and 3 with $T_{avg} \geq 500°F$ is modified by a Note that permits the use of the provisions of Specification 3.0.4.c. This allowance permits entry into the applicable OPERATIONAL MODE(S) while relying on the ACTIONS. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

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BASES

3/4.4.8 SPECIFIC ACTIVITY (Continued)

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity > ~~0.20~~ 0.35 μCi/gram DOSE EQUIVALENT I-131, but within the allowable limit shown on Figure 3.4-1, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER. Operation with specific activity levels exceeding ~~0.20~~ 0.35 μCi/gram DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or exceeding the limits shown on Figure 3.4-1 must be restricted to ensure that assumptions made in the UFSAR accident analyses are not exceeded.

Reducing Tavg to < 500°F minimizes the release of activity should a steam generator tube rupture since the saturation pressure of the primary coolant is below the lift pressure of the atmospheric steam relief valves. This action also reduces the pressure differential across the steam generator tubes reducing the probability and magnitude of main steam line break accident induced primary-to-secondary leakage. The surveillance requirements provide adequate assurance that excessive specific activity levels in the primary coolant will be detected in sufficient time to take corrective action. Information obtained on iodine spiking will be used to assess the parameters associated with spiking phenomena. A reduction in frequency of isotopic analyses following power changes may be permissible if justified by the data obtained.

3/4.4.9 PRESSURE/TEMPERATURE LIMITS

All components in the Reactor Coolant System are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. The various categories of load cycles used for design purposes are provided in Section 4.1.4 of the UFSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

The PTLR contains P/T limit curves for heatup, cooldown, and inservice leak testing, and data for the maximum rate of change of reactor coolant temperature. The analytical methods used to determine the RCS P/T limits and the OPPS limits (PORV pressure relief setpoint and OPPS enable temperature) were developed in accordance with WCAP-14040-NP-A, Rev. 2, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves."

3/4.4.9 PRESSURE/TEMPERATURE LIMITS (Continued)

OVERPRESSURE PROTECTION SYSTEMS

BACKGROUND

The overpressure protection system (OPPS) controls RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G. The reactor vessel is the limiting RCPB component for demonstrating such protection. The maximum setpoint for the power operated relief valves (PORVs) and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup meet the 10 CFR 50, Appendix G (including ASME Code Case N-640) requirements during the OPPS MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures. RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only during shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.9.1, "Pressure/Temperature Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

This LCO provides RCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires deactivating all but one charging pump and isolating the accumulators. The pressure relief capacity requires either two redundant RCS relief valves or a depressurized RCS and an RCS vent of sufficient size. One RCS relief valve or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

With minimum coolant input capability, the ability to provide core coolant addition is restricted. The LCO does not require the makeup control system deactivated or the safety injection (SI) actuation circuits blocked. Due to the lower pressures in the OPPS MODES and the expected core decay heat levels, the makeup system can provide adequate flow via the makeup control valve. The ECCS automatic HHSI flow path ~~through the boron injection tank~~ is required to be isolated by LCO 3.5.4. ~~.1.2.~~

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This page includes changes associated with LAR 326.

3/4.4.9 PRESSURE/TEMPERATURE LIMITS (Continued)

HEAT INPUT TYPE TRANSIENTS (Continued)

The following are required during the OPPS MODES to ensure that mass and heat input transients do not occur, which either of the OPPS overpressure protection means cannot handle:

a. Rendering all but one OPERABLE charging pump, except during pump swapping operations as addressed in the LCO, incapable of injection;

b. Deactivating the accumulator discharge isolation valves in their closed positions;

c. ~~Deactivating the boron injection tank inlet or outlet isolation valves as specified in LCO 3.5.4.1.2, "Boron Injection Tanks < 350°F";~~ Isolating the ECCS automatic HHSI flow path as specified in LCO 3.5.4, "HHSI FLOW PATH"; and

d. Meeting the secondary side water to RCS cold leg temperature difference requirement specified in LCO 3.4.1.3, "Reactor Coolant System - Shutdown."

The analyses demonstrate that either one RCS relief valve or the depressurized RCS and RCS vent can maintain the RCS pressure below the limits when only one charging pump is capable of mass input through the charging line. Thus, the LCO allows only one charging pump OPERABLE during the OPPS MODES. Since neither one RCS relief valve nor the RCS vent can handle a full SI actuation, the LCO also requires that the accumulators are isolated with power removed. In addition LCO 3.5.4~~.1.2~~ requires that the ECCS automatic HHSI ~~injection automatic~~ flow path ~~through the boron injection tank isolation valves~~ is isolated. ~~and power to the boron injection tank flow path valves is removed~~.

The isolated accumulators must have their discharge valves closed with power removed. Fracture mechanics analyses established the temperature of OPPS Applicability at the enable temperature specified in the PTLR.

PORV PERFORMANCE

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the limit specified in the PTLR. The setpoint is derived by analyses that model the performance of the OPPS assuming the limiting OPPS transient of SI actuation of one charging pump. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensures the P/T limits will be met.

BASES

3/4.5.1 ACCUMULATORS

The OPERABILITY of each of the RCS accumulators 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.

The limits on accumulator volume, boron concentration and pressure ensure that the assumptions used for accumulator injection in the accident analysis are met. The specified values for accumulator volume, boron concentration and minimum pressure are analysis values. The Technical Specification maximum pressure is below the maximum analysis pressure so that the relief valve is not challenged at the maximum Technical Specification pressure. The accumulator water volume is provided in gallons and percent indicated level. The percent indicated level does not account for instrumentation uncertainty. The small break LOCA analysis is performed at the minimum nitrogen cover pressure, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak cladding temperature benefit. The maximum nitrogen cover pressure limit prevents accumulator relief valve actuation and ultimately preserves accumulator integrity. The Technical Specification value does not account for instrumentation uncertainty.

If the boron concentration of one accumulator is not within limits (Action a), 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 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. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analysis techniques demonstrate that the accumulators do not discharge following a large main steam line break. 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 (Action b), it must be returned to OPERABLE status within 24 hours. In this condition the required contents of two accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur under these conditions, the 24 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. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status is justified by WCAP-15049-A, Revision 1, "Risk-Informed Evaluation of an Extension to Accumulator Completion Times", dated April 1999.

If the accumulator cannot be returned to OPERABLE status within the associated completion time (Action c), the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to HOT STANDBY within 6 hours and the reactor coolant system pressure reduced to ≤ 1000 psig within 12 hours. The

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS (Continued)

the analysis assumes the pump delivers different flows at different times during accident mitigation. These multiple points are represented by a curve. The values at various flow points are defined by the Minimum Operating Point (MOP) curve in the Inservice Testing (IST) Program. The verification that the pump's developed head at the flow test point is greater than or equal to the required developed head is performed by using the MOP curve. Surveillance requirements are specified in the IST Program, which encompasses Section XI of the ASME Code. Section XI of the ASME Code provides the activities and frequencies necessary to satisfy the requirements.

As indicated in Note 1, operation in MODE 3 with one of the required charging pumps made incapable of injecting in order to support transition into or from the Applicability of Specification 3.4.9.3 is necessary when the OPPS enable temperature is at or near the MODE 3 boundary temperature of 350°F. Specification 3.4.9.3 requires that all but one charging pumps are rendered incapable of injecting at and below the OPPS enable temperature. When this temperature is at or near the MODE 3 boundary temperature, time is needed to render the charging pumps incapable of injecting prior to entering the Applicability of Specification 3.4.9.3, and to restore the inoperable pumps to OPERABLE status upon exiting the Applicability of Specification 3.4.9.3.

As indicated in Note 2, operation in MODE 3 with the HHSI flow path not isolated in order to support transition into or from the Applicability of Specification 3.5.4 is necessary when the OPPS enable temperature is at or near the MODE 3 boundary temperature of 350°F. Specification 3.5.4 requires that HHSI flow path is isolated, thereby rendering it incapable of automatic safety injection at and below the OPPS enable temperature. When this temperature is at or near the MODE 3 boundary temperature, time is needed to render the flow path incapable of injecting prior to entering the Applicability of Specification 3.5.4, and to un-isolate the flow path upon exiting the Applicability of Specification 3.5.4.

BASES

3/4.5.4 ~~BORON INJECTION SYSTEM~~HHSI FLOW PATH

~~The OPERABILITY of the boron injection system as part of the ECCS ensures that sufficient negative reactivity is injected into the core to limit any positive increase in reactivity caused by RCS system cooldown. RCS cooldown can be caused by inadvertent depressurization, a loss-of-coolant accident or a steam line rupture.~~

The ECCS automatic HHSI flow path~~boron injection tank~~ is required to be isolated to prevent a potential overpressurization due to an inadvertent safety injection signal in MODE 4 when any RCS cold leg temperature is less than or equal to an enable temperature specified in the PTLR; in MODE 5; and in MODE 6 when the reactor vessel head is on.
~~when RCS temperature is ≤ the enable temperature specified in the PTLR to prevent a potential overpressurization due to an inadvertent safety injection signal.~~
Isolation of the ECCS automatic HHSI flow path is achieved by closing and de-energizing the flow path isolation valves (either MOV 1SI-867A and MOV 1SI-867B, or MOV 1SI-867C). Surveillance Requirement 4.5.4 provides an exception to the isolation requirement that permits the valves to be open and energized to perform flow or valve stroke testing.

~~The analysis of a main steam pipe rupture is performed to demonstrate that the following criteria are satisfied:~~

1. ~~Assuming a stuck rod cluster control assembly, with or without offsite power, and assuming a single failure in the engineered safeguards, there is no consequential damage to the primary system and the core remains in place and intact.~~

2. ~~Energy release to containment from the worst steam pipe break does not cause failure of the containment structure.~~

3. ~~Radiation doses are not expected to exceed the guidelines of the 10 CFR 100.~~

~~The limits on injection tank minimum volume and boron concentration ensure that the assumptions used in the steam line break analysis are met.~~

BASES

3/4.5.5 SEAL INJECTION FLOW

BACKGROUND

The function of the seal injection throttle valves during an accident is similar to the function of the Emergency Core Cooling Systems (ECCS) throttle valves in that each restricts flow from the charging pump header to the Reactor Coolant System (RCS).

The restriction on reactor coolant pump (RCP) seal injection flow limits the amount of ECCS flow that would be diverted from the injection path following an accident. This limit is based on safety analysis assumptions that are required because RCP seal injection flow is not isolated during SI.

APPLICABLE SAFETY ANALYSES

All ECCS subsystems are taken credit for in the large break loss of coolant accident (LOCA) at full power. The LOCA analysis establishes the minimum flow for the ECCS pumps. The charging pumps are also credited in the small beak LOCA analysis. This analysis establishes the flow and discharge head at the design point for the charging pumps. The steam generator tube rupture and main steam line break event analyses also credit the charging pumps, but are not limiting in their design. Reference to these analyses is made in assessing changes to the Seal Injection System for evaluation of their effects in relation to the acceptance limits in these analyses.

This LCO ensures that seal injection flow of less than or equal to 28 gpm, with charging pump discharge pressure greater than or equal to ~~2397~~2457 psig and seal injection flow control valve full open, will be sufficient for RCP seal integrity but limited so that the ECCS trains will be capable of delivering sufficient water to match boiloff rates soon enough to minimize uncovering of the core following a large LOCA. It also ensures that the charging pumps will deliver sufficient water for a small LOCA and sufficient boron to maintain the core subcritical. For smaller LOCAs, the charging pumps alone deliver sufficient fluid to overcome the loss and maintain RCS inventory.

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BASES

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 accident analyses. This restriction, in conjunction with the leakage rate limitation, —will limit the site boundary radiation doses to within the limits of 10 CFR ~~100~~ 50.67 during accident conditions.

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 accident analyses at the peak accident pressure, P_a. Containment leakage is limited to $\leq 1.0\ L_a$, except prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test. At this time additional leakage limits must be met. As left leakage prior to the first startup after performing a required leakage test is required to be $< 0.60\ L_a$ on a maximum pathway leakage rate (MXPLR) basis for combined Type B and C leakage following an outage or shutdown that included Type B and C testing and $< 0.75\ L_a$ for overall Type A leakage following an outage or shutdown that included Type A testing. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0\ L_a$ and a combined Type B and C leakage limit of $< 0.60\ L_a$ on a minimum pathway leakage rate (MNPLR) basis. The MXPLR for combined Type B and C leakage is the measured leakage through the worst of the two isolation valves, unless a penetration is isolated by use of a valve(s), blind flange(s), or de-activated automatic valve(s). In this case, the MXPLR of the isolated penetration is assumed to be the measured leakage through the isolation device(s).

3/4.6.1.3 CONTAINMENT AIR LOCKS

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder, with a door at each end. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for

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BASES

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 MAIN STEAM SAFETY VALVES (MSSVs)

BACKGROUND

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 overpressurizing the reactor coolant pressure boundary (RCPB) by providing a heat sink for the removal of energy from the Reactor Coolant System (RCS) if the preferred heat sink, provided by the Condenser and Circulating Water System, is not available.

Five MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves, as described in the UFSAR, Section 10.3.1. The specified valve lift settings and design relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, 1971 Edition. The total design relieving capacity for all valves on all of the steam lines is 12.8 x 10^6 lbs/hr which is ~~108~~ approximately 98 percent of the total secondary steam flow of ~~11.8~~13.1 x 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. The MSSVs must have sufficient capacity so that main steam pressure does not exceed 110 percent of the steam generator shell-side design pressure (the maximum pressure allowed by the ASME B&PV Code) for the worst-case loss-of-heat-sink event. This requirement is verified by safety analysis. ~~Based on this requirement, a conservative criterion was applied that the valves should be sized to relieve 100 percent of the maximum calculated steam flow at an accumulation pressure (5 percent) not exceeding 110 percent of the design pressure.~~

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from the ASME Code, Section III and its purpose is to limit the secondary system pressure to less than or equal to 110 percent of design pressure for any anticipated operational occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis.

The events that challenge the relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased heat removal events, which are presented in UFSAR, Section 14.1. Of these, the full power turbine trip without steam dump is the limiting AOO. This event also terminates normal feedwater flow to the steam generators.

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MAIN STEAM SAFETY VALVES (MSSVs) (Continued)

ACTIONS (Continued)

result of an RCS heatup event such that flow capacity of the remaining OPERABLE MSSVs is insufficient. The 4 hour completion time to reduce reactor power is consistent with ACTION a. An additional 32 hours is allowed to reduce the Power Range Neutron Flux-High reactor trip setpoints. The total completion time of 36 hours is based on a reasonable time to correct the MSSV inoperability, the time to perform the power reduction, operating experience to reset all channels of a protection function, and on the low probability of occurrence of a transient that could result in steam generator overpressure during this period.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation discussed above, with an appropriate allowance for Nuclear Instrumentation System trip channel uncertainties.

To determine the Table 3.7-1 Maximum Allowable Power for Action b (% RTP), the calculated Maximum NSSS Power is reduced by ~~5.52~~9.0% to account for Nuclear Instrumentation System trip channel uncertainties. An additional conservatism is employed by setting the values equal to the most conservative between the two units, this being the Unit 1 values.

ACTION b. is modified by a note, indicating that the Power Range Neutron Flux-High reactor trip setpoint reduction is only required in MODE 1. In MODES 2 and 3 the reactor protection system trips specified in LCO 3.3.1.1, "Reactor Trip System Instrumentation," provide sufficient protection.

The allowed completion times are reasonable based on operating experience to accomplish the ACTIONS in an orderly manner without challenging unit systems.

c. If the ACTIONS cannot be completed within the associated completion time, or if one or more steam generators have four or more inoperable MSSVs, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed completion times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

MAIN STEAM SAFETY VALVES (MSSVs) (Continued)

SURVEILLANCE REQUIREMENTS (SR)

SR 4.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME Code, Section XI, requires that safety and relief valve tests be performed in accordance with ANSI/ASME OM-1-1987. According to ANSI/ASME OM-1-1987, the following tests are required:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting); and

d. Compliance with owner's seat tightness criteria.

The ANSI/ASME Standard requires that all valves be tested every 5 years. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7-2 ~~allows a +1 percent 3 percent~~lists the setpoint tolerance for MSSV OPERABILITY; however, the valves are reset to ± 1 percent during the Surveillance to allow for drift.

The lift settings according to Table 3.7-2 correspond to ambient conditions of the valve at nominal operating temperature and pressure, as identified by a note.

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM (AFW)

BACKGROUND (Continued)

an individual line that can be aligned to either the Train "A" or "B" supply header as necessary. Both the Train "A" and "B" supply headers each contain three normally open remotely operated valves arranged in parallel. Each of these valves then provides a flow path to one of the three common feedwater injection headers. Each of the feedwater injection headers then supplies its designated steam generator via the normal feedwater header downstream of the feedwater isolation valves. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) or atmospheric dump valves (ADVs). If the main condenser is available, steam may be released via the steam dump valves.

The AFW System is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions.

During a normal plant cooldown, one pump at full flow is sufficient to remove decay heat and cool the unit to residual heat removal (RHR) entry conditions. Thus, the requirement for diversity in motive power sources for the AFW System is met.

The AFW System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the setpoint of the MSSVs. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the ADVs.

The AFW System actuates automatically on steam generator water level-low-low by the Engineered Safety Feature Actuation System (ESFAS). The system also actuates on loss of offsite power, safety injection, and trip of all operating main feedwater (MFW) pumps.

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest ~~steam generator safety valve~~MSSV set pressure plus 1%.

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM (AFW)

APPLICABLE SAFETY ANALYSES (Continued)

In addition, the AFW System must supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting ~~Design Basis Accident (DBA)~~s for the AFW System ~~is~~ are loss of normal feedwater and feedwater line break (FWLB). ~~the small break loss of coolant accident (SBLOCA).~~

For ~~a SBLOCA~~ the loss of normal feedwater and FWLB, the analyses are performed ~~assuming~~ with and without a loss of offsite power coincident with reactor trip. ~~with a~~ The limiting single active failure is the failure of the turbine driven AFW pump, which results in both motor driven AFW pumps being assumed to be available. ~~of the loss of one train of Emergency Core Cooling System (ECCS) on a failure to start of a diesel generator. The diesel failure is presumed to render one motor driven AFW pump inoperable, which results in one motor driven and one turbine driven AFW pump being operable.~~

The AFW System design is such that it can perform its function following a ~~feedwater line break (FWLB)~~ between the MFW isolation valves and containment, combined with a loss of offsite power following turbine trip, and a single active failure of ~~the steam turbine driven~~ an AFW pump. Sufficient flow would be delivered to the two intact steam generators by the two remaining AFW pumps. ~~following isolation of the break. The analysis assumes a ten minute delay on AFW flow to the steam generator to allow for isolation of the break.~~ No pump runout occurs due to the cavitating venturis. Two motor driven pumps or one motor driven pump combined with the turbine driven pump can deliver the design bases flows to the intact steam generators during a FWLB. There are two distinct flows that must be delivered during a FWLB. They are prior to fault isolation (i.e., during the first 15 minutes) and subsequent to fault isolation via operator action. Any two of the three AFW pumps are capable of supplying the flows required prior and subsequent to fault isolation.

The AFW System design is such that it can perform its function following a total loss of normal feedwater. Any two of the three AFW pumps are capable of supplying the required flows to the three intact steam generators during this event.

With one feedwater injection header inoperable, an insufficient number of steam generators are available to meet the feedline break analysis. This analysis assumes AFW flow will be provided to the two remaining intact feedwater lines. Should a feedline break occur on one of the operable feedwater headers with one feedwater injection header already inoperable, the plant could no longer meet its safety analysis.

The ESFAS automatically actuates the AFW turbine driven pump and associated power operated valves and controls when required to ensure an adequate feedwater supply to the steam generators during loss of power. Power operated valves are provided for each AFW line to control the AFW flow to each steam generator.

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Three AFW pumps in three diverse trains are required to be OPERABLE to ensure the availability of RHR capability

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BASES

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM (AFW)

SURVEILLANCE REQUIREMENTS (SR) (Continued)

outages to determine no misalignment of valves has occurred. This SR ensures that the flow path from the WT-TK-10 to the steam generators is properly aligned.

3/4.7.1.3 PRIMARY PLANT DEMINERALIZED WATER

The OPERABILITY of the PPDW storage tank with the minimum water volume ensures that sufficient water is available ~~for cooldown of the Reactor Coolant System to less than 350°F in the event of a total loss of off-site power. The minimum water volume is sufficient~~ to maintain the RCS at HOT STANDBY (hot zero power) conditions for 9 hours with steam discharge to atmosphere with no reactor coolant pumps in operation. The minimum usable volume conservatively bounds the analysis value. The minimum usable volume may be appropriately increased to account for measurement uncertainties.

3/4.7.7 CONTROL ROOM EMERGENCY HABITABILITY SYSTEM

The OPERABILITY of the control room emergency habitability system ensures that the control room will remain habitable for operations personnel during and following all credible accident conditions. The ambient air temperature is controlled to prevent exceeding the allowable equipment qualification temperature for the equipment and instrumentation in the control room. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to ~~5 rem or less whole body, or its equivalent, or~~ 5 rem TEDE. ~~, as applicable.~~ This limitation is consistent with the requirements of ~~General Design Criteria 19 of Appendix "A", 10 CFR 50 or~~ 10 CFR 50.67. ~~, as applicable.~~

The control room dose calculation for the limiting DBA assumes that the control room is pressurized within 30 minutes of the accident by manually actuating a control room emergency ventilation subsystem (CREVS). Although the Unit 1 CREVS pressurization fan is manually actuated, the specification requires automatic actuation of the Unit 2 CREVS pressurization fans.

A start time delay is included in the initiation circuitry of the Unit 2 CREVS pressurization fans. The basis for this time delay includes the following considerations:

1. The delay times prevent loading of the pressurization fans onto the emergency busses until after the Unit 2 Emergency Diesel Generator load sequencing is completed.

2. The pressurization fan delay times are staggered to ensure only one fan will be operating.

3. A pressurization fan is started early to minimize dose to the operators.

4. The delay times are selected such that sufficient time will be available for the manual initiation of the Unit 1 pressurization fan within 30 minutes after an accident should a Unit 2 pressurization fan fail to start.

The design basis of the control room emergency habitability system purge function ensures the capability to manually purge the air from the control room for selected design basis accidents to ensure acceptable dose consequences to the control room personnel follow a DBA.

The main steam line break (MSLB) and Steam Generator Tube rupture (SGTR) accident analysis credit a manually initiated 30 minute control room ventilation purge at a flow rate greater than or equal to 16,200 cfm, after the accident sequence is complete and the environmental release has been terminated. Also, the Fuel Handling Accident (FHA) analysis credits a manually initiated 30 minute control room ventilation purge at a flow rate greater than or equal to 16,200 cfm, after the accident sequence is complete and the environmental release has been terminated. The dose consequence analyses assume that for the MSLB, the SGTR and the FHA, the control room purge is initiated at T=24 hours, T= 8 hours and T= 2 hours, respectively.

Attachment B-2

Beaver Valley Power Station, Unit No. 2

Proposed Technical Specification Bases Changes

License Amendment Request No. 173

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B 3/4 7-2j	
B 3/4 7-4	
B 3/4-7-5	

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 and therefore THERMAL POWER and Reactor Coolant Temperature and Pressure have been related to DNB through the WRB-1, WRB-2, WRB-2M, and W-3 correlations. ~~The WRB-1 DNB~~These correlations ~~has~~have 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, defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, is indicative of the margin to DNB. The WRB-1 and WRB-2M DNB correlations are associated with transients that could impact the reactor core safety limits. These correlations, along with the WRB-2 and W-3 DNB correlations, are used in support of the licensing basis transient analyses.

The DNB thermal design criterion is that the probability of DNB not occurring on the most limiting rod is at least 95 percent at a 95 percent confidence level for any Condition I or II event.

In meeting the DNB design criterion with the Revised Thermal Design Procedure (RTDP), uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters and computer codes have been statistically combined with the DNB correlation uncertainties to determine the DNBR Design Limits which are ~~1.24 for typical and 1.23 for thimble cell~~1.23/1.22 (typical cell/thimble cell) for Vantage 5H (V5H) fuel assemblies, and 1.22/1.22 (typical cell/thimble cell) for Robust Fuel Assemblies (RFA). In addition, margin has been maintained in the design by meeting a safety analysis DNBR limit of 1.33 for typical cells and 1.32 for thimble cells for WRB-1, and 1.55 for typical and thimble cells for WRB-2M, in performing safety analyses.

The Standard Thermal Design Procedure (STDP) is used for those analyses where RTDP is not applicable. With this procedure, the nominal values with uncertainties are used to calculate DNBRs. The DNBR limits for STDP are the appropriate correlation limits increased by sufficient margin to offset the applicable DNBR penalties.

The figure provided in the COLR shows the loci of points of THERMAL POWER, Reactor Coolant System pressure and average temperature for which the minimum DNBR is no less than the safety analysis DNBR limit, or the average enthalpy at the vessel exit is equal to the enthalpy of saturated liquid. The figure is based on enthalpy hot channel factor limits provided in the COLR.

3/4.1.1 BORATION CONTROL

3/4.1.1.1 and 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 T_{avg}. The most restrictive condition occurs at EOL, with T_{avg} at no load operating temperature, and is associated with a postulated steam line break accident and resulting uncontrolled RCS cooldown. In the analysis of this accident, a minimum SHUTDOWN MARGIN of 1.77% $\Delta k/k$ is initially required to control the reactivity transient. Accordingly, the SHUTDOWN MARGIN requirement is based upon this limiting condition and is consistent with FSAR accident analysis assumptions. With $T_{avg} \leq 200°F$, the reactivity transients resulting from a postulated steam line break cooldown are minimal and a 1% $\Delta k/k$ SHUTDOWN MARGIN provides adequate protection.

The purpose of borating to the COLD SHUTDOWN boron concentration prior to blocking safety injection is to preclude a return to criticality should a steam line break occur during plant heatup or cooldown.

3/4.1.1.3 BORON DILUTION

A minimum flow rate of at least 3000 GPM provides adequate mixing, prevents stratification and ensures that reactivity changes will be gradual during boron concentration reductions in the Reactor Coolant System. A flow rate of at least 3000 GPM will circulate ~~an equivalent~~ the Reactor Coolant System volume ~~of 9370 cubic feet~~ in approximately 30 minutes. The reactivity change rate associate with boron reductions will therefore be within the capability for operator recognition and control.

3/4.1.1.4 MODERATOR TEMPERATURE COEFFICIENT (MTC)

The limitations on MTC are provided to ensure that the assumptions used in the accident and transient analyses remain valid through each fuel cycle. The surveillance requirement for measurement of the MTC at the beginning and near the end of each fuel cycle is adequate to confirm the MTC value since this coefficient changes slowly due principally to the reduction in RCS boron concentration associated with fuel burnup.

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

Manual Reactor Trip

The Manual Reactor Trip is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

Power Range, Neutron Flux

The Power Range, Neutron Flux channel high setpoint provides reactor core protection against reactivity excursions which are too rapid to be protected by temperature and pressure protective circuitry. The low setpoint provides redundant protection in the power range for a power excursion beginning from low power. The trip associated with the low setpoint may be manually bypassed when P-10 is active (two of the four power range channels indicate a power level of above the P-10 setpoint) and is automatically reinstated when P-10 becomes inactive (three of the four channels indicate a power level below the P-10 setpoint).

Power Range, Neutron Flux, High Positive Rate~~s~~

The Power Range Positive Rate trip provides protection against rapid flux increases which are characteristic of rod ejection events from any power level. Specifically, this trip complements the Power Range Neutron Flux High and Low trips to ensure that the criteria are met for rod ejection from partial power.

~~The Power Range Negative Rate trip provides protection to ensure that the minimum DNBR is maintained above the design DNBR limit for control rod drop accidents. At high power a multiple rod drop accident could cause local flux peaking which, when in conjunction with nuclear power being maintained equivalent to turbine power by action of the automatic rod control system, could cause an unconservative local DNBR to exist. The Power Range Negative Rate trip will prevent this from occurring by tripping the reactor. No credit is taken for operation of the Power Range Negative Rate trip for those control rod drop accidents for which DNBRs will be greater than the design DNBR limit.~~

Intermediate and Source Range, Nuclear Flux

The Intermediate and Source Range, Nuclear Flux trips provide reactor 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

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BASES

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

the low setpoint trip of the Power Range, Neutron Flux channels. The Source Range Channels will initiate a reactor trip at the trip setpoint unless manually blocked when P-6 becomes active. The intermediate range channels will initiate a reactor trip at a current level proportional to the trip setpoint unless manually blocked when P-10 becomes active. Although no explicit credit was taken for operation of the Source Range Channels in the accident analyses, operability requirements in the Technical Specifications will ensure that the Source Range Channels are available to mitigate the consequences of an inadvertent control bank withdrawal in MODES 3, 4 and 5.

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, thermowell, and RTD response time delays from the core to the temperature detectors ~~(about 4 seconds)~~, and pressure is within the range between the High and Low pressure reactor trips. This setpoint includes corrections for changes in density and heat capacity of water with temperature and dynamic compensation for transport, thermowell, and RTD response time delays from the core to RTD output indication. 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 notation in Table 3.3-1.

Overpower ΔT

The Overpower ΔT reactor trip provides assurance of fuel integrity, e.g., no melting, under all possible overpower conditions, limits the required range for Overtemperature ΔT protection, and provides a backup to the High Neutron Flux Trip. The setpoint includes corrections for changes in density and heat capacity of water with temperature, and dynamic compensation for transport, thermowell, and RTD response time delays from the core to RTD output indication. ~~The Overpower ΔT trip provides protection to mitigate the consequences of various size steam line breaks as reported in WCAP-9226, "Reactor Core Response to Excessive Secondary Steam Release."~~

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

Undervoltage and Underfrequency - Reactor Coolant Pump Busses

The Undervoltage and Underfrequency Reactor Coolant Pump bus trips provide reactor core protection against DNB as a result of loss of voltage or underfrequency to more than one reactor coolant pump. The trip setpoints assure a reactor trip signal is generated before the low flow trip setpoint is reached. Time delays are incorporated in the underfrequency and undervoltage trips to prevent spurious reactor trips from momentary electrical power transients. For undervoltage, the delay is set so that the time required for a signal to reach the reactor trip breakers following the simultaneous trip of two or more reactor coolant pump bus circuit breakers shall not exceed 1.2 seconds. For underfrequency, the delay is set so that the time required for a signal to reach the reactor trip breakers after the underfrequency trip setpoint is reached shall not exceed 0.6 seconds.

On decreasing power, the Undervoltage and Underfrequency Reactor Coolant Pump bus trips are automatically blocked by P-7; and on increasing power, reinstated automatically by P-7.

Turbine Trip

A Turbine Trip causes a direct reactor trip when operating above P-9. Each of the turbine trips provides turbine protection and reduces the severity of the ensuing transient. No credit was taken in the accident analyses for operation of these trips. Their functional capability at the specified trip settings is required to enhance the overall reliability of the Reactor Protection System.

Safety Injection Input from ESF

If a reactor trip has not already been generated by the reactor protective instrumentation, the ESF automatic actuation logic channels will initiate a reactor trip upon any signal which initiates a safety injection. This trip is provided to protect the core in the event of a LOCA and a steamline break (SLB). 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 resulting from the opening of two or more pump breakers above P-7. These trips are blocked below P-7. The open/close position trips assure a reactor

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This page includes changes associated with LAR 184.

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

~~The maximum response time for control room isolation on high radiation is based on ensuring that the control room remains habitable following a small line break outside the containment. From a control room habitability aspect, the worst case accident that does not initiate a Containment Isolation - Phase B signal is the small line break outside the containment. This response time includes radiation monitor processing delays associated with the monitor averaging techniques. Diesel Generator starting and sequence loading delays are not included since these delays occur prior to the control room environment exceeding the high radiation setpoint.~~

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) in place, onsite, or offsite (e.g., vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements" provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

WCAP-14036-P-A Revision 1, "Elimination of Periodic Protection Channel Response Time Tests" and WCAP-15413, "Westinghouse 7300A ASIC-Based Replacement Module Licensing Summary Report" provide the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time. The allocations for sensor, signal conditioning and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components identified in the WCAP may be replaced without verification testing. One example where response time could be affected is replacing the sensing assembly of a transmitter. WCAP-15413 provides bounding response times where 7300 cards have been replaced with ASICs cards.

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

P-4 Reactor tripped - Actuates turbine trip, closes main feedwater valves on T_{avg} below setpoint, prevents the opening of the main feedwater valves which were closed by a safety injection or high steam generator water level signal, allows safety injection block so that components can be reset or tripped.

Reactor not tripped - prevents manual block of safety injection.

P-11 Above the setpoint, P-11 automatically reinstates safety injection actuation on low pressurizer pressure, automatically blocks steamline isolation on high steam pressure rate, and enables safety injection and steamline isolation (with Loop Stop Valve Open) on low steamline pressure. Below the setpoint, P-11 allows the manual block of safety injection actuation on low pressurizer pressure, allows manual block of safety injection and steamline isolation (with Loop Stop Valve Open) on low steamline pressure and enables steamline isolation on high steam pressure rate.

P-12 Above the setpoint, P-12 automatically reinstates an arming signal to the steam dump system. Below the setpoint P-12 blocks steam dump and allows manual bypass of the steam dump block to cooldown condenser dump valves.

3/4.4.5 STEAM GENERATORS (Continued)

decay heat removal capabilities for RCS temperatures greater than 350°F if one steam generator becomes inoperable due to single failure considerations. Below 350°F, decay heat is removed by the RHR system.

The Surveillance Requirements for inspection of the steam generator tubes ensure that the structural integrity of this portion of the RCS will be maintained. The program for inservice inspection of steam generator tubes is based on a modification of Regulatory Guide 1.83, Revision 1. Inservice inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

The plant is expected to be operated in a manner such that the secondary coolant will be maintained within those parameter limits found to result in negligible corrosion of the steam generator tubes. If the secondary coolant chemistry is not maintained within these parameter limits, localized corrosion may likely result in stress corrosion cracking. The extent of cracking during plant operation would be limited by the limitation of steam generator tube leakage between the Primary Coolant System and the Secondary Coolant System (primary-to-secondary LEAKAGE = 150 gallons per day per steam generator). Axial cracks having a primary-to-secondary LEAKAGE less than this limit during operation will have an adequate margin of safety to withstand the loads imposed during normal operation and by postulated accidents. Operating plants have demonstrated that primary-to-secondary LEAKAGE of 150 gallons per day per steam generator can readily be detected. LEAKAGE in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged or repaired by sleeving. The technical bases for sleeving are described in the approved vendor reports listed in Surveillance Requirement 4.4.5.4.a.9, as supplemented by Westinghouse letter FENOC-02-304.

Wastage-type defects are unlikely with the all volatile treatment (AVT) of secondary coolant. However, even if a defect of similar type should develop in service, it will be found during scheduled inservice steam generator tube examinations. Plugging or repair will be required of all tubes with imperfections exceeding the plugging or repair limit. Degraded steam generator tubes may be repaired by the installation of sleeves which span the degraded tube section. A steam generator tube with a sleeve installed meets the structural

3/4.4.5 STEAM GENERATORS (Continued)

where V_{Gr} represents the allowance for degradation growth between inspections and V_{NDE} represents the allowance for potential sources of error in the measurement of the bobbin coil voltage. Further discussion of the assumptions necessary to determine the voltage repair limit are discussed in GL 95-05.

Safety analyses were performed pursuant to Generic Letter 95-05 to determine the maximum MSLB-induced primary-to-secondary leak rate that could occur without offsite doses exceeding a small fraction of 10 CFR ~~100~~50.67 guidelines (considering a concurrent iodine spike), 10 CFR ~~100~~ 50.67 (pre-accident iodine spike), and without control room doses exceeding ~~GDC 19~~10 CFR 50.67. The current value of the maximum MSLB-induced leak rate and a summary of the analyses are provided in Section 15.1.5 of the UFSAR.

The mid-cycle equation in SR 4.4.5.4.a.10.d should only be used during unplanned inspections in which eddy current data is acquired for indications at the tube support plates.

SR 4.4.5.5 implements several reporting requirements recommended by GL 95-05 for situations which the NRC wants to be notified prior to returning the SGs to service. For the purposes of this reporting requirement, leakage and conditional burst probability can be calculated based on the as-found voltage distribution rather than the projected end-of-cycle (EOC) voltage distribution (refer to GL 95-05 for more information) when it is not practical to complete these calculations using the projected EOC voltage distributions prior to returning the SGs to service. Note that if leakage and conditional burst probability were calculated using the measured EOC voltage distribution for the purposes of addressing the GL section 6.a.1 and 6.a.3 reporting criteria, then the results of the projected EOC voltage distribution should be provided per the GL section 6.b (c) criteria.

Whenever the results of any steam generator tubing inservice inspection fall into Category C-3, these results will be reported to the Commission pursuant to Specification 6.6 prior to resumption of plant operation. Such cases will be considered by the Commission on a case-by-case basis and may result in a requirement for analysis, laboratory examinations, tests, additional eddy-current inspection, and revision of the Technical Specifications, if necessary.

3/4.4.6.2 OPERATIONAL LEAKAGE (Continued)

BACKGROUND (Continued)

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.

10 CFR 50, Appendix A, GDC 30, requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 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 percent leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES

Except for primary-to-secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes a ~~1 gpm~~ 450 gpd primary-to-secondary LEAKAGE as the initial condition. An exception to the primary-to-secondary LEAKAGE is described below for the main steamline break (MSLB) analyzed in support of voltage-based steam generator tube repair criteria.

3/4.4.6.2 OPERATIONAL LEAKAGE (Continued)

APPLICABLE SAFETY ANALYSES (Continued)

~~Primary-to-secondary LEAKAGE is a factor in the dose releases outside containment resulting from a MSLB accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.~~

~~The MSLB is more limiting for site radiation releases. The primary-to-secondary LEAKAGE assumed in the safety analysis for the MSLB accident is described in UFSAR Section 15.1.5. The radiological consequences of a MSLB outside of containment was reanalyzed in support of the tube support plate voltage-based repair criteria stated in SR 4.4.5.4.a.10. For this analysis, the thyroid dose was maximized at 10% of the 10 CFR Part 100 guideline of 300 rem for the co-incident iodine spike case. RCS leakage was based on projection rather than on technical specification leakage limits. The analysis indicated that offsite doses would remain within regulatory criteria with the assumed primary-to-secondary leakage (described in UFSAR Section 15.1.5) should steam generator tubes fail due to the depressurization associated with a MSLB.~~

~~A similar analysis was performed using a control room thyroid dose of 30 rem as the criterion. The control room was assumed to be manually isolated and pressurized at T=30 minutes for a period of one hour, at which time filtered emergency intake would be automatically started. The control room would be purged with fresh air at T=8 hours following release cessation. The analysis indicated that control room doses would remain within regulatory criteria with the assumed primary-to-secondary leakage (described in UFSAR Section 15.1.5) should steam generator tubes fail due to the depressurization associated with a MSLB.~~

Primary-to-secondary LEAKAGE is a factor in the dose assessment of accidents or transients that involve secondary steam release to the atmosphere, such as a main steam line break (MSLB), a locked rotor accident (LRA), a Loss of AC Power (LACP), a Control Rod Ejection Accident (CREA) and to a lesser extent, a Steam Generator Tube Rupture (SGTR). The leakage contaminates the secondary fluid. The limit on the primary-to-secondary leakage ensures that the dose contribution at the site boundary from tube leakage following such accidents are limited to appropriate fractions of the 10 CFR 50.67 limit of 25 Rem TEDE as allowable by Regulatory Guide 1.183. The limit on the primary-to-secondary leakage also ensures that the dose contribution from tube leakage in the control room is limited to the 10 CFR 50.67 limit of 5 Rem TEDE. Among all of the analyses that release primary side activity to the environment via tube leakage, the MSLB is of particular concern because the ruptured main steam line provides a pathway to release the primary to secondary leakage directly to the environment without dilution in the secondary fluid.

Due to adoption of the voltage based steam generator tube repair criteria per guidance provided by Generic Letter 95-05, the safety analysis for an event resulting in steam discharge to the atmosphere conservatively assumes a 450 gpd primary-to-secondary LEAKAGE (150 gpd per steam generator) for all accidents other that the MSLB. The dose consequences associated with the MSLB addresses an accident-induced leakage, which, per Generic Letter 95-05, is postulated to occur (via pre-existing tube defects) as a result of the rapid depressurization of the secondary side due to the MLSB, and the consequent high differential pressure across the faulted steam generator. The maximum allowed accident induced leakage is 2.1 gpm.

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. Should pressure boundary LEAKAGE occur through a

3/4.4.7 (This Specification number is not used.)

3/4.4.8 SPECIFIC ACTIVITY

The primary coolant specific activity is limited in order to maintain offsite and control room operator doses associated with postulated accidents within applicable requirements. Specifically, the 0.35 µCi/gm DOSE EQUIVALENT I-131 limit ensures that the offsite TEDE dose ~~does not exceed a small fraction of 10 CFR Part 100 guidelines~~ is limited to appropriate fractions of the 10 CFR 50.67 limit of 25 rem TEDE as allowable by Regulatory Guide 1.183 (for the co-incident iodine spike), and that control room operator ~~thyroid~~ TEDE dose does not exceed ~~GDC 19~~ the 10 CFR 50.67 guideline in the event of primary-to-secondary leakage induced by a main steam line break.

Required Action "a" for MODES 1 , 2 and 3 with $T_{avg} \geq 500°F$ is modified by a Note that permits the use of the provisions of Specification 3.0.4.c. This allowance permits entry into the applicable OPERATIONAL MODE(S) while relying on the ACTIONS. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity > 0.35 µCi/gram DOSE EQUIVALENT I-131, but within the allowable limit shown on Figure 3.4-1, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER. Operation with specific activity levels exceeding 0.35 µCi/gram DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or exceeding the limits shown on Figure 3.4-1 must be restricted to ensure that assumptions made in the UFSAR accident analyses are not exceeded.

Reducing T_{avg} to < 500°F minimizes the release of activity should a steam generator tube rupture since the saturation pressure of the primary coolant is below the lift pressure of the atmospheric steam relief valves. This action also reduces the pressure differential across the steam generator tubes reducing the probability and magnitude of main steam line break accident induced primary-to-secondary leakage. The surveillance requirements provide adequate assurance that excessive specific activity levels in the primary coolant will be detected in sufficient time to take corrective action. Information obtained on iodine spiking will be used to assess the parameters associated with spiking phenomena. A reduction in frequency of isotopic analyses following power changes may be permissible if justified by the data obtained.

BASES

3/4.5.1 ACCUMULATORS

The OPERABILITY of each of the RCS accumulators 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.

The limits on accumulator volume, boron concentration and pressure ensure that the assumptions used for accumulator injection in the accident analysis are met. The specified values for accumulator volume, boron concentration and minimum pressure are analysis values. The Technical Specification maximum pressure is below the maximum analysis pressure so that the relief valve is not challenged at the maximum Technical Specification pressure. The accumulator water volume is provided in gallons and percent indicated level. The percent indicated level does not account for instrumentation uncertainty. The small break LOCA analysis is performed at the minimum nitrogen cover pressure, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak cladding temperature benefit. The maximum nitrogen cover pressure limit prevents accumulator relief valve actuation and ultimately preserves accumulator integrity. The Technical Specification value does not account for instrumentation uncertainty.

If the boron concentration of one accumulator is not within limits (Action a), 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 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. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analysis techniques demonstrate that the accumulators do not discharge following a large main steam line break. 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 (Action b), it must be returned to OPERABLE status within 24 hours. In this condition the required contents of two accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur under these conditions, the 24 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 actions 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. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status is justified by WCAP-15049-A, Revision 1, "Risk-Informed Evaluation of an Extension to Accumulator Completion Times", dated April 1999.

If the accumulator cannot be returned to OPERABLE status within the associated completion time (Action c), the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to HOT STANDBY within 6 hours and the reactor coolant system pressure reduced to ≤ 1000 psig within 12 hours. The

3/4.5.4 SEAL INJECTION FLOW

BACKGROUND

The function of the seal injection throttle valves during an accident is similar to the function of the Emergency Core Cooling Systems (ECCS) throttle valves in that each restricts flow from the charging pump header to the Reactor Coolant Systems (RCS).

The restriction on reactor coolant pump (RCP) seal injection flow limits the amount of ECCS flow that would be diverted from the injection path following an accident. This limit is based on safety analysis assumptions that are required because RCP seal injection flow is not isolated during SI.

APPLICABLE SAFETY ANALYSES

All ECCS subsystems are taken credit for in the large break loss of coolant accident (LOCA) at full power. The LOCA analysis establishes the minimum flow for the ECCS pumps. The charging pumps are also credited in the small break LOCA analysis. This analysis establishes the flow and discharge head at the design point for the charging pumps. The steam generator tube rupture and main steam line break event analyses also credit the charging pumps, but are not limiting in their design. Reference to these analyses is made in assessing changes to the Seal Injection System for evaluation of their effects in relation to the acceptance limits in these analyses.

This LCO ensures that seal injection flow of less than or equal to 28 gpm, with charging pump discharge pressure greater than or equal to ~~2410~~2457 psig and seal injection flow control valve full open, will be sufficient for RCP seal integrity but limited so that the ECCS trains will be capable of delivering sufficient water to match boiloff rates soon enough to minimize uncovering of the core following a large LOCA. It also ensures that the charging pumps will deliver sufficient water for a small LOCA and sufficient boron to maintain the core subcritical. For smaller LOCAs, the charging pumps alone deliver sufficient fluid to overcome the loss and maintain RCS inventory.

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 accident analyses. This restriction, in conjunction with the leakage rate limitation, will limit the site boundary radiation doses to within the limits of 10 CFR ~~100~~ 50.67 during accident conditions.

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 accident analyses at the peak accident pressure, P_a. Containment leakage is limited to $\leq 1.0\ L_a$, except prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test. At this time additional leakage limits must be met. As left leakage prior to the first startup after performing a required leakage test is required to be $< 0.60\ L_a$ on a maximum pathway leakage rate (MXPLR) basis for combined Type B and C leakage following an outage or shutdown that included Type B and C testing and $< 0.75\ L_a$ for overall Type A leakage following an outage or shutdown that included Type A testing. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0\ L_a$ and a combined Type B and C leakage limit of $< 0.60\ L_a$ on a minimum pathway leakage rate (MNPLR) basis. The MXPLR for combined Type B and C leakage is the measured leakage through the worst of the two isolation valves, unless a penetration is isolated by use of a valve(s), blind flange(s), or de-activated automatic valve(s). In this case, the MXPLR of the isolated penetration is assumed to be the measured leakage through the isolation device(s).

3/4.6.1.3 CONTAINMENT AIR LOCKS

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder, with a door at each end. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. The emergency air lock, which is located in the equipment hatch

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 MAIN STEAM SAFETY VALVES (MSSVs)

BACKGROUND

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 overpressurizing the reactor coolant pressure boundary (RCPB) by providing a heat sink for the removal of energy from the Reactor Coolant System (RCS) if the preferred heat sink, provided by the Condenser and Circulating Water System, is not available.

Five MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves, as described in the UFSAR, Section 10.3.2. The specified valve lift settings and design relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, 1971 Edition and Winter 1972 Addenda. The total design relieving capacity for all valves on all of the steam lines is 12.7 x 10^6 lbs/hr which is ~~108~~ approximately 97 percent of the total secondary steam flow of ~~11.8~~13.1 x 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. The MSSVs must have sufficient capacity so that main steam pressure does not exceed 110 percent of the steam generator shell-side design pressure (the maximum pressure allowed by the ASME B&PV Code) for the worst-case loss-of-heat-sink event. This requirement is verified by safety analysis.~~Based on this requirement, a conservative criterion was applied that the valves should be sized to relieve 100 percent of the maximum calculated steam flow at an accumulation pressure (3 percent) not exceeding 110 percent of the design pressure.~~

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from the ASME Code, Section III and its purpose is to limit the secondary system pressure to less than or equal to 110 percent of design pressure for any anticipated operational occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis.

The events that challenge the relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased heat removal events, which are presented in UFSAR, Section 15.2. Of these, the full power turbine trip without steam dump is the limiting AOO. This event also terminates normal feedwater flow to the steam generators.

MAIN STEAM SAFETY VALVES (MSSVs) (Continued)

ACTIONS (Continued)

result of an RCS heatup event such that flow capacity of the remaining OPERABLE MSSVs is insufficient. The 4 hour completion time to reduce reactor power is consistent with ACTION a. An additional 32 hours is allowed to reduce the Power Range Neutron Flux-High reactor trip setpoints. The total completion time of 36 hours is based on a reasonable time to correct the MSSV inoperability, the time to perform the power reduction, operating experience to reset all channels of a protection function, and on the low probability of occurrence of a transient that could result in steam generator overpressure during this period.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation discussed above, with an appropriate allowance for Nuclear Instrumentation System trip channel uncertainties.

To determine the Table 3.7-1 Maximum Allowable Power for Action b (% RTP), the calculated Maximum NSSS Power is reduced by ~~5.52~~9.0% to account for Nuclear Instrumentation System trip channel uncertainties. An additional conservatism is employed by setting the values equal to the most conservative between the two units, this being the Unit 1 values.

ACTION b. is modified by a note, indicating that the Power Range Neutron Flux-High reactor trip setpoint reduction is only required in MODE 1. In MODES 2 and 3 the reactor protection system trips specified in LCO 3.3.1.1, "Reactor Trip System Instrumentation," provide sufficient protection.

The allowed completion times are reasonable based on operating experience to accomplish the ACTIONS in an orderly manner without challenging unit systems.

c. If the ACTIONS are not completed within the associated completion time, or if one or more steam generators have four or more inoperable MSSVs, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed completion times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

MAIN STEAM SAFETY VALVES (MSSVs) (Continued)

SURVEILLANCE REQUIREMENTS (SR)

SR 4.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME Code, Section XI, requires that safety and relief valve tests be performed in accordance with ANSI/ASME OM-1-1987. According to ANSI/ASME OM-1-1987, the following tests are required:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting); and

d. Compliance with owner's seat tightness criteria.

The ANSI/ASME Standard requires that all valves be tested every 5 years. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7-2 ~~allows a +1 percent -3 percent~~lists the setpoint tolerance for MSSV OPERABILITY; however, the valves are reset to ± 1 percent during the Surveillance to allow for drift.

The lift settings according to Table 3.7-2 correspond to ambient conditions of the valve at nominal operating temperature and pressure, as identified by a note.

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM (AFW)

BACKGROUND (Continued)

The AFW System is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions.

During a normal plant cooldown, one pump at full flow is sufficient to remove decay heat and cool the unit to residual heat removal (RHR) entry conditions. Thus, the requirement for diversity in motive power sources for the AFW System is met.

The AFW System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the setpoint of the MSSVs. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the ADVs.

The AFW System actuates automatically on steam generator water level-low-low by the Engineered Safety Feature Actuation System (ESFAS). The system also actuates on loss of offsite power, safety injection, and trip of all operating main feedwater (MFW) pumps.

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest ~~steam generator safety valve~~MSSV set pressure plus 1%.

In addition, the AFW System must supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting ~~Design Basis Accident (DBA~~s~~)~~ for the AFW System ~~is~~ are loss of normal feedwater and feedwater line break (FWLB). ~~the small break loss of coolant accident (SBLOCA).~~

For the loss of normal feedwater and FWLB ~~a SBLOCA~~, the analyses are performed ~~assuming~~ with and without a loss of offsite power coincident with reactor trip. ~~with a~~ The limiting single active failure is the failure of the turbine driven AFW pump, which results in both motor driven AFW pumps being assumed to be available. ~~of the loss of one train of Emergency Core Cooling System (ECCS) on a failure to start of a diesel generator. The diesel failure is presumed to render one motor driven AFW pump inoperable, which results in one motor driven and one turbine driven AFW pump being operable.~~

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM (AFW)

APPLICABLE SAFETY ANALYSES (Continued)

The AFW System design is such that it can perform its function following a ~~feedwater line break (FWLB)~~ between the MFW isolation valves and containment, combined with a loss of offsite power following turbine trip, and a single active failure of ~~the steam turbine driven~~an AFW pump. Sufficient flow would be delivered to the two intact steam generators by the two remaining AFW pump~~(s)~~. No pump runout occurs due to the cavitating venturis. ~~The design bases flow to the intact steam generators during a feedwater line break can be delivered by either two motor driven, the turbine driven, or one motor driven and the turbine driven pump. The flow is delivered without operator action to isolate the break.~~ Two motor driven pumps or one motor driven pump combined with the turbine driven pump can deliver the design bases flows to the intact steam generators during a FWLB. There are two distinct flows that must be delivered during a FWLB. They are prior to fault isolation (i.e., during the first 15 minutes) and subsequent to fault isolation via operator action. Any two of the three AFW pumps are capable of supplying the flows required prior and subsequent to fault isolation.

The AFW System design is such that it can perform its function following a total loss of normal feedwater. Any two of the three AFW pumps are capable of supplying the required flows to the three intact steam generators during this event.

With one feedwater injection header inoperable, an insufficient number of steam generators are available to meet the feedline break analysis. This analysis assumes AFW flow will be provided to the two remaining intact feedwater lines. Should a feedline break occur on one of the operable feedwater headers with one feedwater injection header already inoperable, the plant could no longer meet its safety analysis.

The ESFAS automatically actuates the AFW turbine driven pump and associated power operated valves and controls when required to ensure an adequate feedwater supply to the steam generators during loss of power. Power operated valves are provided for each AFW line to control the AFW flow to each steam generator.

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Three AFW pumps in three diverse trains are required to be OPERABLE to ensure the availability of RHR capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two of the pumps from independent emergency buses. The third AFW pump is powered by a different means, a steam driven turbine supplied with steam from a source that is not isolated by closure of the main steam isolation valves (MSIVs).

The AFW System is configured into three trains. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. This

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BASES

3/4.7.1.3 PRIMARY PLANT DEMINERALIZED WATER (PPDW)

The OPERABILITY of the PPDW storage tank with the minimum water volume ensures that sufficient water is available to maintain the RCS at HOT STANDBY (hot zero power) conditions for 9 hours with steam discharge to atmosphere with no reactor coolant pumps in operation. The minimum usable volume conservatively bounds the analysis value. The minimum usable volume may be appropriately increased to account for measurement uncertainties.

3/4.7.1.4 ACTIVITY

The limitations on secondary system specific activity ensure that steam releases to the environment will not be significant contributors to radioactivity releases resulting from analyzed accidents. Many of the analyzed accidents assume that a loss of auxiliary AC power occurs, making the main condenser unavailable for plant cooldown, and making it necessary to dump steam to the environment via SG atmospheric dump valves. Maintaining secondary system specific activity within the limits ensures that these releases, in conjunction with other releases associated with the accident, will be within applicable dose criteria.

3/4.7.6 (This Specification number is not used.)

3/4.7.7 CONTROL ROOM EMERGENCY AIR CLEANUP AND PRESSURIZATION SYSTEM

This LCO is applicable during MODES 1, 2, 3 and 4. This LCO is also applicable during movement of recently irradiated fuel assemblies and during movement of fuel assemblies over recently irradiated fuel assemblies because there is a potential for the limiting fuel handling accident (FHA) for which the requirements of this Specification may be required to limit radiation exposure to personnel occupying the control room. A FHA which does not involve recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 100 hours) will result in radiation exposure, to personnel occupying the control room, that is within the guideline values specified in 10 CFR 50.67 without any reliance on the requirements of this Specification to limit personnel exposure. The 100 hour limit is based on the current radiological analysis for a FHA which assumes a decay time of 100 hours. LCO 3.9.3 prohibits irradiated fuel movement unless 100 hours of decay has occurred. Therefore, this specification will not be applicable, during fuel movement, unless the decay time in Specification 3.9.3 and the time assumed in the radiological analysis for a FHA are reduced to below 100 hours.

The OPERABILITY of the control room emergency air cleanup and pressurization system ensures that the control room will remain habitable with respect to potential radiation hazards for operations personnel during and following all credible accident conditions. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to ~~5 rem or less whole body, or its equivalent, or~~ 5 rem TEDE.~~, as applicable.~~ This limitation is consistent with the requirements of ~~General Design Criteria 19 of Appendix "A", 10 CFR 50 or~~ 10 CFR 50.67.~~, as applicable.~~

3/4.7.7 CONTROL ROOM EMERGENCY AIR CLEANUP AND PRESSURIZATION SYSTEM (Continued)

The control room air cleanup and pressurization system consists of two redundant filtration pressurization systems which draw outside air through filters and Unit 1 and Unit 2 air intake and exhaust isolation dampers. Closure of the intake and exhaust dampers can be initiated by Unit 2 control systems. However, closure of dampers in one intake and in one exhaust is dependent upon availability of Unit 1 power sources.

The control room dose calculation for the limiting DBA assumes that the control room is pressurized within 30 minutes of the accident by manually actuating a control room emergency ventilation subsystem (CREVS). However, the specification requires automatic actuation of the Unit 2 CREVS pressurization fans.

A start time delay is included in the initiation circuitry of the Unit 2 CREVS pressurization fans. The basis for this time delay includes the following considerations:

1. The delay times prevent loading of the pressurization fans onto the emergency busses until after the Emergency Diesel Generator load sequencing is completed.

2. The pressurization fan delay times are staggered to ensure only one fan will be operating.

3. A pressurization fan is started early to minimize dose to the operators.

4. The delay times are selected such that sufficient time will be available for the manual initiation of a pressurization fan within 30 minutes after an accident should a pressurization fan fail to start.

The design basis of the control room emergency habitability system purge function ensures the capability to manually purge the air from the control room for selected design basis accidents to ensure acceptable dose consequences to the control room personnel follow a DBA.

The main steam line break (MSLB) and Steam Generator Tube rupture (SGTR) accident analysis credit a manually initiated 30 minute control room ventilation purge at a flow rate greater than or equal to 16,200 cfm, after the accident sequence is complete and the environmental release has been terminated. The dose consequence analyses assume that for the MSLB and the SGTR, the control room purge is initiated at T=24 hours and T= 8 hours, respectively.

Attachment C-1

Beaver Valley Power Station, Unit No. 1

Proposed Licensing Requirements Manual Changes

License Amendment Request No. 302

The following is a list of the affected pages:

Page	Pending LAR
1.0-3	
3.1-2	
3.1-3	
3.2-3	317
3.2-5	317
3.8-1	
3.9-2	327
3.9-4	317
3.9-5	317
3.9-6	327
4.1-1	
4.1-2	
4.1-6	
4.1-7	
4.1-8	
4.1-9	
4.2-6	
4.2-7	
6.5-1	
B.3-3	

1.0 GENERAL REQUIREMENTS

1.0.1 Definitions

The defined terms contained in the Technical Specifications Section 1.0, "Definitions" apply to the requirements contained in this manual. In the Licensing Requirements Manual (LRM), defined terms are shown in all capital letters, consistent with their use in the Technical Specifications.

1.0.1.a RATED THERMAL POWER

The value of RATED THERMAL POWER, as per Technical Specification Definition 1.3, is 2689 MWt.

1.0.2 Failure to meet a Licensing Requirement (LR) or Licensing Requirement Surveillance (LRS) in the LRM

When either a) the requirements of an LR are not met and the associated Actions are not met or an associated Action is not provided or b) when the requirements of an LRS are not met:

1. A condition report shall be written, and
2. The safety significance of the non-conforming condition shall be evaluated and appropriate corrective actions initiated as required by Appendix B of 10 CFR Part 50. The time frame for completion of the corrective actions shall be commensurate with the safety significance of the condition, consistent with the guidance of NRC Generic Letter 91-18.

Exceptions to this requirement are provided in Sections 1.1 and 1.2 of the LRM for such things as restoring equipment to OPERABLE status, and surveillance interval extensions.

1.0.3 Technical Specification Related Information

Other requirements specified in the LRM such as those contained in tables, reports, or figures (e.g., Instrumentation Response Times and COLR) are not associated with an LR or LRS. These requirements are contained in the LRM because they are referenced from within the Technical Specifications. The guidance in this manual for implementing LRs and LRSs does not apply to the LRM requirements referenced from within the Technical Specifications. The failure to meet LRM requirements referenced from within the Technical Specifications shall be controlled by the applicable Technical Specifications.

1.0.4 LRM Revisions

Modifications to the content of the LRM (including the Technical Specification related information discussed in 1.0.3 above) shall be processed in accordance with 1/2-ADM-2206. 1/2-ADM-2206 provides guidance for changing the LRM in accordance with the provisions of 10 CFR 50.59.

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TABLE 3.1-1
REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

	FUNCTIONAL UNIT	RESPONSE TIME
1.	Manual Reactor Trip	NOT APPLICABLE
2.	Power Range, Neutron Flux	≤ 0.5 seconds(1)
3.	Power Range, Neutron Flux, High Positive Rate	NOT APPLICABLE
4.	~~Power Range, Neutron Flux, High Negative Rate~~Deleted	~~≤ 0.5 seconds(1)~~
5.	Intermediate Range, Neutron Flux	NOT APPLICABLE
6.	Source Range, Neutron Flux	NOT APPLICABLE
7.	Overtemperature ΔT	Variable(1)(2)
8.	Overpower ΔT	Variable(1)(2)
9.	Pressurizer Pressure -- Low	≤ 2.0 seconds
10.	Pressurizer Pressure -- High	≤ 2.0 seconds
11.	Pressurizer Water Level -- High	NOT APPLICABLE
12.	Loss of Flow - Single Loop (Above P-8)	≤ 1.0 seconds
13.	Loss of Flow - Two Loops (Above P-7 and below P-8)	≤ 1.0 seconds
14.	Steam Generator Water Level -- Low-Low	≤ 2.0 seconds
15.	Deleted	
16.	Undervoltage-Reactor Coolant Pumps	≤ 1.2 seconds
17.	Underfrequency-Reactor Coolant Pumps	≤ 0.6 seconds
18.	Turbine Trip	
	A. Auto Stop Oil Pressure	NOT APPLICABLE
	B. Turbine Stop Valve	NOT APPLICABLE
19.	Safety Injection Input from ESF	NOT APPLICABLE
20.	Reactor Coolant Pump Breaker Position Trip	NOT APPLICABLE

TABLE NOTATION

(1) Neutron detectors are exempt from response time testing. Response time shall be measured from detector output or input of first electronic component in channel.

(2) Refer to Table 3.1-1.a for required response times.

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TABLE 3.1-1.a
Combined Overtemperature Delta-T & Overpower Delta-T Response Times

This table represents the maximum allowable plant testing, electronic response time acceptance criteria based on measured RTD response time. All listed values are in seconds.

To use this table, take the slowest measured RTD response time in a loop, round up to the nearest 1/10 second, and obtain the corresponding acceptance criteria.

Replace with Insert C1-1.

~~Time Response Testing*~~		~~Time Response Testing*~~	
~~RTD Time Response~~	~~Acceptance Criteria~~	~~RTD Time Response~~	~~Acceptance Criteria~~
~~2.0~~	~~2.112~~		
~~2.1~~	~~2.103~~	~~4.6~~	~~1.878~~
~~2.2~~	~~2.094~~	~~4.7~~	~~1.868~~
~~2.3~~	~~2.085~~	~~4.8~~	~~1.859~~
~~2.4~~	~~2.076~~	~~4.9~~	~~1.850~~
~~2.5~~	~~2.068~~	~~5.0~~	~~1.841~~
~~2.6~~	~~2.059~~	~~5.1~~	~~1.831~~
~~2.7~~	~~2.050~~	~~5.2~~	~~1.822~~
~~2.8~~	~~2.041~~	~~5.3~~	~~1.813~~
~~2.9~~	~~2.032~~	~~5.4~~	~~1.803~~
~~3.0~~	~~2.023~~	~~5.5~~	~~1.794~~
~~3.1~~	~~2.014~~	~~5.6~~	~~1.785~~
~~3.2~~	~~2.005~~	~~5.7~~	~~1.775~~
~~3.3~~	~~1.996~~	~~5.8~~	~~1.766~~
~~3.4~~	~~1.987~~	~~5.9~~	~~1.757~~
~~3.5~~	~~1.978~~	~~6.0~~	~~1.747~~
~~3.6~~	~~1.969~~	~~6.1~~	~~1.738~~
~~3.7~~	~~1.960~~	~~6.2~~	~~1.728~~
~~3.8~~	~~1.951~~	~~6.3~~	~~1.719~~
~~3.9~~	~~1.942~~	~~6.4~~	~~1.710~~
~~4.0~~	~~1.932~~	~~6.5~~	~~1.700~~
~~4.1~~	~~1.923~~	~~6.6~~	~~1.691~~
~~4.2~~	~~1.914~~	~~6.7~~	~~1.681~~
~~4.3~~	~~1.905~~	~~6.8~~	~~1.672~~
~~4.4~~	~~1.896~~	~~6.9~~	~~1.661~~
~~4.5~~	~~1.888~~	~~7.0~~	~~1.651~~

~~*All values are in seconds.~~

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Insert C1-1.

RTD Time Response	Final Accept. Criteria Overtemperature ΔT - T_{avg} Input	Final Accept. Criteria Overpower ΔT - T_{avg} Input	Final Accept. Criteria Measured ΔT - ΔT Input	RTD Time Response	Final Accept. Criteria Overtemperature ΔT - T_{avg} Input	Final Accept. Criteria Overpower ΔT - T_{avg} Input	Final Accept. Criteria Measured ΔT - ΔT Input
2.0	2.862	2.643	9.883	4.6	2.366	2.264	7.367
2.1	2.840	2.625	9.777	4.7	2.349	2.251	7.279
2.2	2.818	2.609	9.672	4.8	2.333	2.239	7.190
2.3	2.796	2.592	9.568	4.9	2.316	2.226	7.102
2.4	2.775	2.575	9.464	5.0	2.300	2.214	7.014
2.5	2.754	2.559	9.362	5.1	2.283	2.202	6.927
2.6	2.733	2.543	9.260	5.2	2.267	2.190	6.840
2.7	2.713	2.527	9.159	5.3	2.250	2.178	6.754
2.8	2.693	2.512	9.059	5.4	2.235	2.166	6.668
2.9	2.673	2.497	8.960	5.5	2.218	2.154	6.582
3.0	2.654	2.481	8.861	5.6	2.202	2.143	6.497
3.1	2.634	2.467	8.763	5.7	2.187	2.131	6.412
3.2	2.615	2.452	8.666	5.8	2.171	2.120	6.327
3.3	2.596	2.438	8.569	5.9	2.156	2.108	6.242
3.4	2.578	2.423	8.473	6.0	2.140	2.097	6.158
3.5	2.559	2.409	8.378	6.1	2.040	1.997	6.058
3.6	2.541	2.395	8.283	6.2	1.940	1.897	5.958
3.7	2.523	2.382	8.189	6.3	1.840	1.797	5.858
3.8	2.505	2.368	8.096	6.4	1.740	1.697	5.758
3.9	2.487	2.354	8.003	6.5	1.640	1.597	5.658
4.0	2.469	2.341	7.911	6.6	1.540	1.497	5.558
4.1	2.452	2.328	7.819	6.7	1.440	1.397	5.458
4.2	2.434	2.315	7.728	6.8	1.340	1.297	5.358
4.3	2.417	2.302	7.637	6.9	1.240	1.197	5.258
4.4	2.400	2.289	7.547	7.0	1.140	1.097	5.158
4.5	2.383	2.276	7.457				

The following are the response time acceptance criteria for the pressurizer pressure and neutron flux input to the Overtemperature ΔT function:

Pressurizer pressure input: ≤ 2.0 seconds.
Neutron detector input (for f(ΔI) penalty): ≤ 2.0 seconds.

All of the channel time responses noted above for the Overtemperature ΔT, Overpower ΔT, and measured ΔT channels are for all portions of the channel downstream of the RTD output (i.e., includes channel electronics, trip breaker, and rod gripper release). The time responses are based on all channel setpoints (i.e., all gains and time constants) implemented as per the Licensing Requirements Manual values.

This page contains changes associated with LAR 317.

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TABLE 3.2-1 (Continued)
ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION		RESPONSE TIME IN SECONDS
3.	Pressurizer Pressure-Low	
	a. Safety Injection (ECCS)	≤ 17.0(10)/27.0(3)/27.0(4)
	b. Reactor Trip (from SI)	≤ 3.0
	c. Feedwater Isolation	
	1) Feedwater Regulating Valves	≤ 10.0(6)
	~~2) Feedwater Bypass Valves~~	~~≤ 30.0(6)~~
	3) Feedwater Isolation Valves	≤ 10.0(6)
	d. Containment Isolation-Phase "A"	≤ 22.0(8)
	e. Auxiliary Feedwater Pumps	≤ 60.0
	f. Rx Plant River Water System	≤ 77.0(8)/110.0(7)
4.	Steam Line Pressure-Low	
	a. Safety Injection (ECCS)	≤ 27.0(4)/37.0(5)
	b. Reactor Trip (from SI)	≤ 3.0
	c. Feedwater Isolation	
	1) Feedwater Regulating Valves	≤ 10.0(6)
	~~2) Feedwater Bypass Valves~~	~~≤ 30.0(6)~~
	3) Feedwater Isolation Valves	≤ 10.0(6)
	d. Containment Isolation-Phase "A"	≤ 22.0(8)/33.0(7)
	e. Auxiliary Feedwater Pumps	≤ 60.0
	f. Rx Plant River Water System	≤ 77.0(8)/110.0(7)
	g. Steam Line Isolation	≤ 8.0
5.	Containment Pressure--High-High	
	a. Containment Quench Spray	≤ 81.5(9)
	b. Containment Isolation-Phase "B"	Not Applicable
	c. Control Room Ventilation Isolation	≤ 22.0(8)/77.0(7)

This page contains changes associated with LAR 317.

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TABLE 3.2-1 (Continued)
ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
13. Trip of Main Feedwater Pumps	
a. Motor-driven Auxiliary Feedwater Pumps	≤ 60.0

TABLE NOTATION

(1) on 2/3 any Steam Generator

(2) on 2/3 in 2/3 Steam Generators

(3) Diesel generator starting and sequence loading delays included. Response time limit includes opening of valves to establish SI path and attainment of discharge pressure for centrifugal charging pumps and Low Head Safety Injection pumps. Sequential transfer of charging pump suction from the volume control tank (VCT) to the refueling water storage tank (RWST) (RWST valves open, then VCT valves close) is <u>not</u> included.

(4) Diesel generator starting and sequence loading delays <u>not</u> included. Offsite power available. Response time limit includes opening of valves to establish SI path and attainment of discharge pressure for centrifugal charging pumps. Sequential transfer of charging pump suction from the volume control tank (VCT) to the refueling water storage tank (RWST) (RWST valves open, then VCT valves close) is included.

(5) Diesel generator starting and sequence loading delays included. Response time limit includes opening of valves to establish SI path and attainment of discharge pressure for centrifugal charging pumps. Sequential transfer of charging pump suction from the volume control tank (VCT) to the refueling water storage tank (RWST) (RWST valves open, then VCT valves close) is included.

(6) Feedwater isolation includes signal response and valve closure time.

(7) Diesel generator starting and sequence loading delays included.

(8) Diesel generator starting and sequence loading delays <u>not</u> included.

(9) Diesel generator starting and sequence loading delays included. This response time also includes pump total start time (pump acceleration, begin to deliver flow, etc.) and time to fill the spray piping with water. The maximum allowable isolation valve stroke time is included in the Quench Spray analysis of record. Note that the stroke time of the containment quench spray isolation valves [MOV-1QS-101A, B] is verified in Licensing Requirements Manual Table 5.1-1 "Containment Penetrations."

(10) Diesel generator starting and sequence loading delays **not** included. Offsite power available. Response time limit includes opening of valves to establish SI path and attainment of discharge pressure for centrifugal charging pumps and Low Head Safety Injection pumps. Sequential transfer of charging pump suction from the volume control tank (VCT) to the refueling water storage tank (RWST) (RWST valves open, then VCT valves close) is **not** included.

3.8 LEADING EDGE FLOW METER

LICENSING REQUIREMENT

LR 3.8 An OPERABLE Leading Edge Flow Meter (LEFM) shall be used in the performance of the daily calorimetric heat balance measurements to determine steady-state THERMAL POWER as required by Item 2.a of the Unit 1 Technical Specifications Table 4.3-1.

APPLICABILITY: MODE 1 when steady-state THERMAL POWER is > ~~2652 MWt~~ 98.6% of RTP.

ACTION:

a. With the LEFM inoperable, restore to OPERABLE status prior to the next required daily calorimetric heat balance measurement, or

b. Within one hour, reduce steady-state THERMAL POWER to ≤ ~~2652 MWt.~~ 98.6% of RTP. Perform the calorimetric heat balance measurement using the feedwater flow venturis and Resistance Temperature Detector (RTD) indications. Maintain THERMAL POWER at ≤ ~~2652 MWt~~ 98.6% of RTP steady state until the LEFM is restored to OPERABLE status and the calorimetric heat balance measurement has been performed using the LEFM.

LICENSING REQUIREMENT SURVEILLANCE

LRS 3.8.1 The LEFM shall be demonstrated to be OPERABLE at least once every 24 hours, by using the self-diagnostic features of the LEFM.

LRS 3.8.2 The LEFM shall be demonstrated to be OPERABLE at least once every 18 months, by performing the periodic maintenance and inspections recommended by the manufacturer.

Provided for Information Only.

TABLE 3.9-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

	FUNCTIONAL UNIT	NOMINAL TRIP SETPOINT
1.	Manual Reactor Trip	Not Applicable
2.	Power Range, Neutron Flux	
	A. High Setpoint	109% of RATED THERMAL POWER
	B. Low Setpoint	25% of RATED THERMAL POWER
3.	Power Range, Neutron Flux, High Positive Rate	5% of RATED THERMAL POWER with a time constant ≥ 2 seconds
4.	~~Power Range, Neutron Flux, High Negative Rate~~Deleted	~~5% of RATED THERMAL POWER with a time constant ≥ 2 seconds~~
5.	Intermediate Range, Neutron Flux	25% of RATED THERMAL POWER
6.	Source Range, Neutron Flux	
	A. With Rod Withdrawal Capability	10^5 counts per second
	B. With All Rods Fully Inserted and Without Rod Withdrawal Capability	Not Applicable
7.	Overtemperature ΔT	See Technical Specification Table Notation (A) on Table 3.3-1
8.	Overpower ΔT	See Technical Specification Table Notation (B) on Table 3.3-1
9.	Pressurizer Pressure-Low	1945 psig
10.	Pressurizer Pressure-High	2385 psig
11.	Pressurizer Water Level-High	92% of instrument span
12.	Loss of Flow	
	A. Single Loop	90.2% of indicated loop flow
	B. Two Loops	90.2% of indicated loop flow
13.	Steam Generator Water Level-Low-Low	~~20.1~~19.6% of narrow range instrument span-~~each~~ steam generator
14.	Deleted	

This page contains changes associated with LAR 327.

This page contains changes associated with LAR 317.

Provided for Information Only.

TABLE 3.9-2

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	NOMINAL TRIP SETPOINT
1. SAFETY INJECTION AND FEEDWATER ISOLATION	
a. Manual Initiation	Not Applicable
b. Automatic Actuation Logic	Not Applicable
c. Containment Pressure-High	5.0 psig
d. Pressurizer Pressure-Low	1845 psig
e. Steamline Pressure-Low	500 psig steam line pressure*
1.1 SAFETY INJECTION-TRANSFER FROM INJECTION TO THE RECIRCULATION MODE	
a. Manual Initiation	Not Applicable
b. Automatic Actuation Logic Coincident with Safety Injection Signal	Not Applicable
c. Refueling Water Storage Tank Level-Low	14' 1/2"
2. CONTAINMENT SPRAY	
a. Manual	Not Applicable
b. Automatic Actuation Logic	Not Applicable
c. Containment Pressure--High-High	11.1 psig

* Time constants utilized in the lead-lag controllers for Steam Line Pressure-Low are $\tau_1 \geq 50$ seconds and $\tau_2 \leq 5$ seconds. CHANNEL CALIBRATION shall ensure that these time constants are adjusted to these values.

This page contains changes associated with LAR 317.

Provided for Information Only.

TABLE 3.9-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	NOMINAL TRIP SETPOINT
3. CONTAINMENT ISOLATION	
a. Phase "A" Isolation	
1. Manual	Not Applicable
2. From Safety Injection Automatic Actuation Logic	Not Applicable
b. Phase "B" Isolation	
1. Manual	Not Applicable
2. Automatic Actuation Logic	Not Applicable
3. Containment Pressure--High-High	11.1 psig
4. STEAM LINE ISOLATION	
a. Manual	Not Applicable
b. Automatic Actuation Logic	Not Applicable
c. Containment Pressure Intermediate-High-High	7.0 psig
d. Steamline Pressure-Low	500 psig steam line pressure*
e. Steamline Pressure Rate-High Negative	100 psi with a time constant ≥ 50 seconds
5. TURBINE TRIP & FEEDWATER ISOLATION	
a. Steam Generator Water Level--High-High	~~81.2~~89.7% of narrow range instrument span each steam generator

* Time constants utilized in the lead-lag controllers for Steam Line Pressure-Low are $\tau_1 \geq 50$ seconds and $\tau_2 \leq 5$ seconds. CHANNEL CALIBRATION shall ensure that these time constants are adjusted to these values.

TABLE 3.9-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM
INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	NOMINAL TRIP SETPOINT
6. LOSS OF POWER	
a. 4.16 kv Emergency Bus Undervoltage	
1. Loss of Voltage (Trip Feed)	75% of rated bus voltage with a 1 ± 0.1 second time delay
2. Loss of Voltage (Start Diesel)	75% of rated bus voltage with a < 0.9 second time delay (includes auxiliary relay times)
b. 4.16kv Emergency Bus Undervoltage (Degraded Voltage)	93.7% of rated bus voltage with a 90 ± 5 second time delay
c. 480v Emergency Bus Undervoltage (Degraded Voltage)	93.7% of rated bus voltage with a 90 ± 5 second time delay
7. AUXILIARY FEEDWATER	
a. Steam Generator Water Level-Low-Low	
i. Start Turbine Driven Pump	~~20.1~~ 19.6% of narrow range instrument span ~~each~~ steam generator
ii. Start Motor Driven Pumps	~~20.1~~ 19.6% of narrow range instrument span ~~each~~ steam generator
b. Undervoltage - RCP (Start Turbine Driven Pump)	75% rated RCP bus voltage
c. S.I. (Start All Auxiliary Feedwater Pumps)	See 1 above (all SI Setpoints)
d. (Deleted)	
e. Trip of Main Feedwater Pumps (Start Motor Driven Pumps)	Not Applicable
8. ESF INTERLOCKS	
a. Reactor Trip, P-4	Not Applicable
b. Pressurizer Pressure, P-11	2000 psig
c. Low-Low Tavg, P-12	541°F

4.1 CORE OPERATING LIMITS REPORT

This Core Operating Limits Report provides the cycle specific parameter limits developed in accordance with the NRC approved methodologies specified in Technical Specification Administrative Control 6.9.5.

<u>Specification 3.1.3.5 Shutdown Rod Insertion Limits</u>

The shutdown rods shall be withdrawn to at least 225 steps.*

<u>Specification 3.1.3.6 Control Rod Insertion Limits</u>

Control Banks A and B shall be withdrawn to at least 225 steps.*

Control Banks C and D shall be limited in physical insertion as shown in Figure 4.1-1.*

<u>Specification 3.2.1 Axial Flux Difference</u>

NOTE: The target band is ±7% about the target flux from 0% to 100% RATED THERMAL POWER.

The indicated Axial Flux Difference:

a. Above 90% RATED THERMAL POWER shall be maintained within the ±7% target band about the target flux difference.

b. Between 50% and 90% RATED THERMAL POWER is within the limits shown on Figure 4.1-2.

c. Below 50% RATED THERMAL POWER may deviate outside the target band.

<u>Specification 3.2.2 $F_Q(Z)$ and F_{xy} Limits</u>

$$F_Q(Z) \leq \frac{CF_Q}{P} * K(Z) \qquad \text{for } P > 0.5$$

$$F_Q(Z) \leq \frac{CF_Q}{0.5} * K(Z) \qquad \text{for } P \leq 0.5$$

Where: CF_Q = ~~2.3~~<u>2.40</u> $\qquad P = \dfrac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$

K(Z) = the function obtained from Figure 4.1-3.

* As indicated by the group demand counter

The F_{xy} limits [$F_{xy}(L)$] for RATED THERMAL POWER within specific core planes shall be:

$F_{xy}(L) = F_{xy}(RTP)(1 + PF_{xy} * (1\text{-}P))$

Where: For all core planes containing D-Bank:

$F_{xy}(RTP) \leq 1.71$

For unrodded core planes:

$F_{xy}(RTP) \leq 1.75$ from 1.8 ft. elevation to 2.3 ft. elevation

$F_{xy}(RTP) \leq 1.80$ from 2.3 ft. elevation to 3.7 ft. elevation

$F_{xy}(RTP) \leq 1.83$ from 3.7 ft. elevation to 7.4 ft. elevation

$F_{xy}(RTP) \leq 1.79$ from 7.4 ft. elevation to 9.2 ft. elevation

$F_{xy}(RTP) \leq 1.74$ from 9.2 ft. elevation to 10.2 ft. elevation

Provided as an example.

$PF_{xy} = 0.2$

$P = \dfrac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$

Figure 4.1-4 provides the maximum total peaking factor times relative power ($F_Q^T*P_{rel}$) as a function of axial core height during normal core operation.

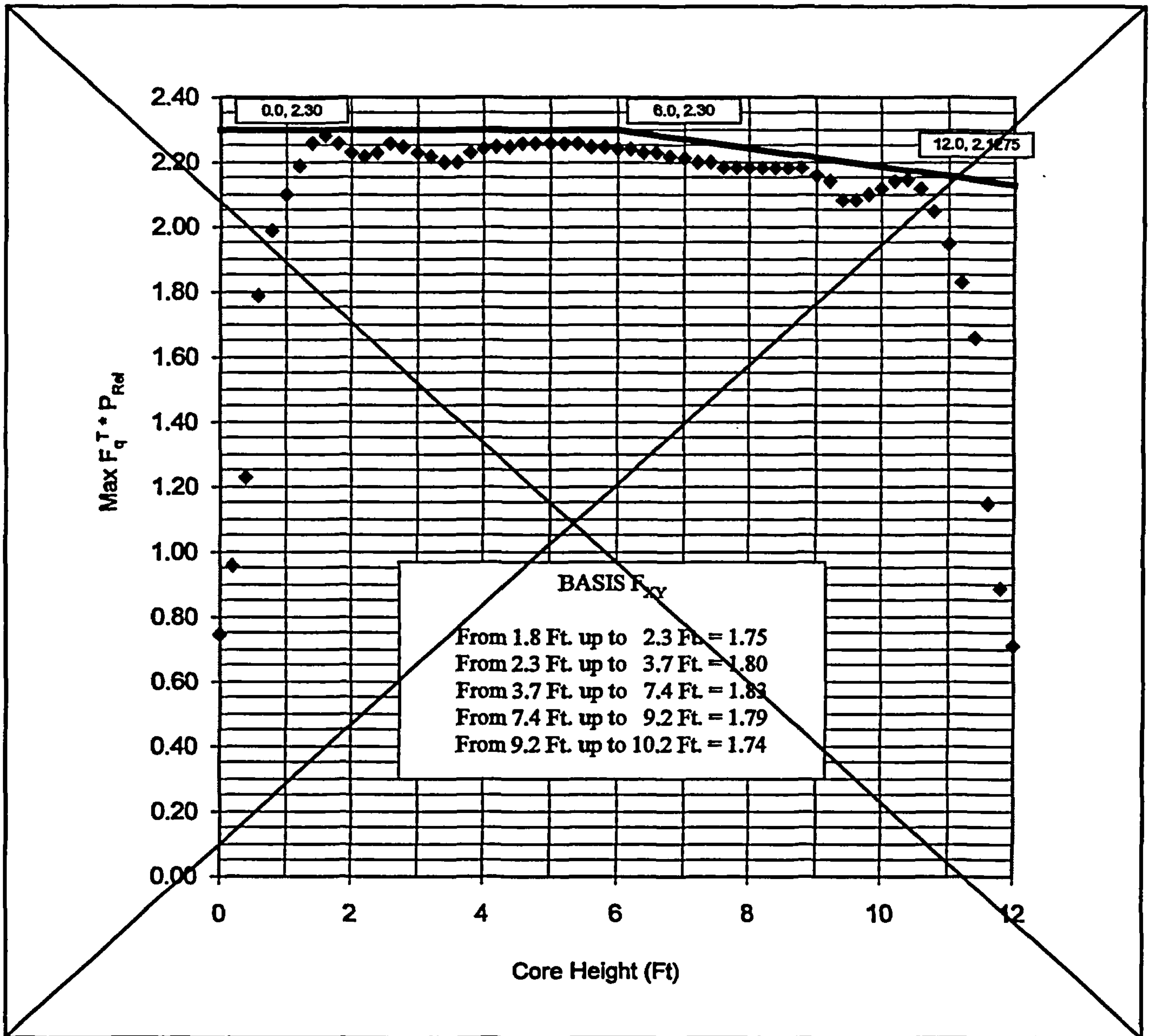
Specification 3.2.3 $F^N_{\Delta H}$

$F^N_{\Delta H} \leq CF_{\Delta H} * (1 + PF_{\Delta H}(1\text{-}P))$

Where: $CF_{\Delta H} = 1.62$ for Robust Fuel Assemblies and 1.456 for Vantage 5H Assembles.

$PF_{\Delta H} = 0.3$

$P = \dfrac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$



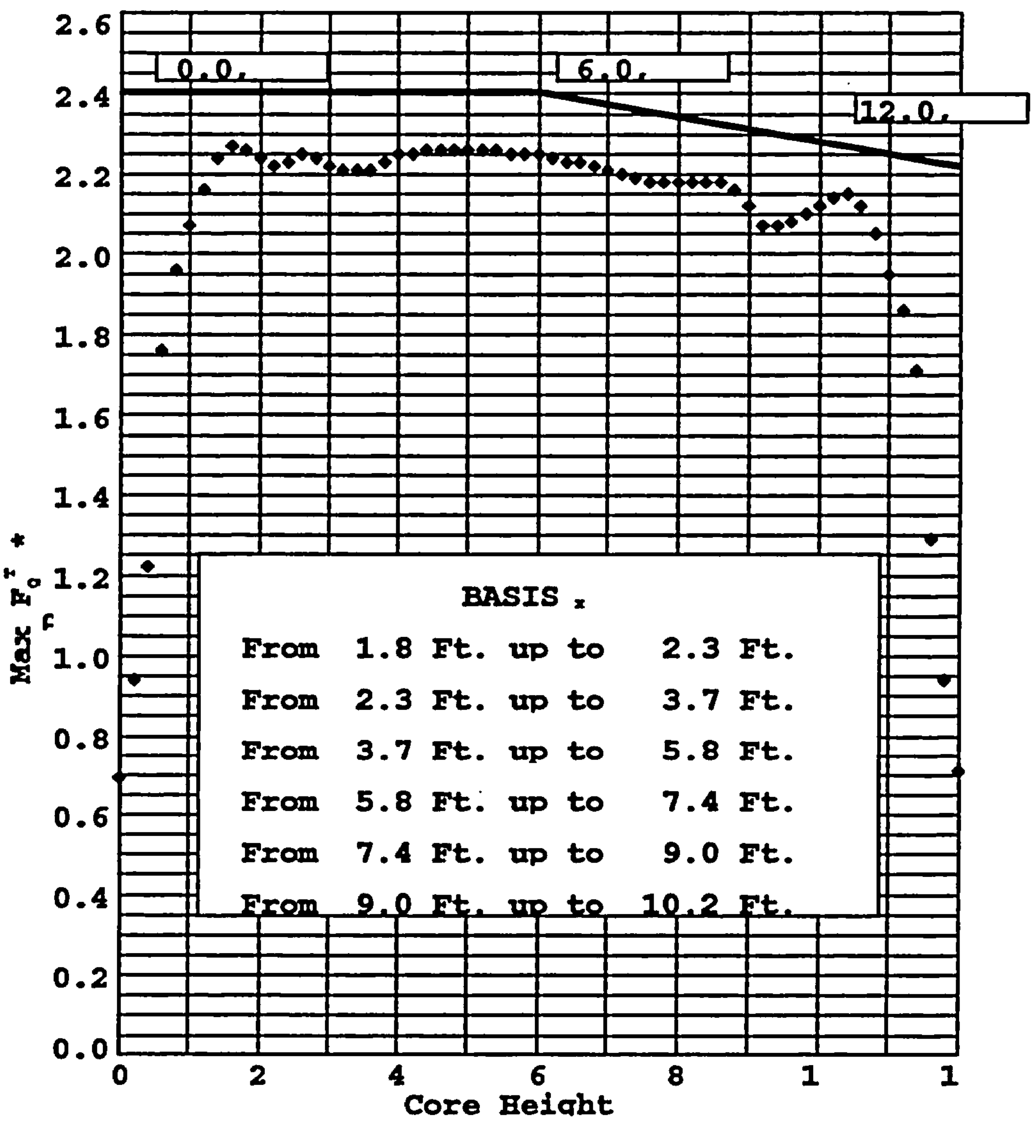
Replace with Insert C1-2.

FIGURE 4.1-4
MAXIMUM (F_QT*PREL) VS AXIAL CORE HEIGHT DURING NORMAL OPERATION

Provided for Information Only.

Insert C1-2.

Provided as an example.



Specification 3.3.1.1 Reactor Trip System Instrumentation Setpoints, Table 3.3-1 Table Notations A and B

Overtemperature ΔT Setpoint Parameter Values:

Parameter	Value
Overtemperature ΔT reactor trip setpoint	K1 ≤ ~~1.259~~1.242
Overtemperature ΔT reactor trip setpoint Tavg coefficient	K2 ≥ ~~0.01655~~0.0183/°F
Overtemperature ΔT reactor trip setpoint pressure coefficient	K3 ≥ ~~0.000801~~0.001/psia
Tavg at RATED THERMAL POWER	T' ≤ ~~576.2~~580.0°F
Nominal Pressurizer Pressure	P' ≥ 2250 psia
Measured reactor vessel average temperature lead/lag time constants	$\tau_1 \geq 30$ secs $\tau_2 \leq 4$ secs
Measured reactor vessel ΔT lag time constant	$\tau_4 \leq 6$ secs
Measured reactor vessel average temperature lag time constant	$\tau_5 \leq 2$ secs

f (ΔI) is a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(i) for $q_t - q_b$ between ~~-36~~48 percent and ~~+15~~10 percent, f (ΔI) = 0 (where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER).

(ii) for each percent that the magnitude of $(q_t - q_b)$ exceeds ~~-36~~ 48 percent, the ΔT trip setpoint shall be automatically reduced by ~~2.08~~4.67 percent of its value at RATED THERMAL POWER.

(iii) for each percent that the magnitude of $(q_t - q_b)$ exceeds ~~+15~~ 10 percent, the ΔT trip setpoint shall be automatically reduced by ~~1.59~~1.47 percent of its value at RATED THERMAL POWER.

~~Overpower ΔT Setpoint Parameter Values:~~

~~Parameter~~	~~Value~~
~~Overpower ΔT reactor trip setpoint~~	~~K4 ≤ 1.0916~~
~~Overpower ΔT reactor trip setpoint Tavg rate/lag coefficient~~	~~K5 ≥ 0.02/°F for increasing average temperature~~

Overpower ΔT Setpoint Parameter Values ~~(continued)~~:

Parameter	Value
Overpower ΔT reactor trip setpoint	K4 ≤ ~~1.0916~~1.085
Overpower ΔT reactor trip setpoint Tavg rate/lag coefficient	K5 ≥ 0.02/°F for increasing average temperature K5 = 0/°F for decreasing average temperature
Overpower ΔT reactor trip setpoint Tavg heatup coefficient	K6 ≥ ~~0.00128~~0.0021/°F for T > T" K6 = 0/°F for T ≤ T"
Tavg at RATED THERMAL POWER	T" ≤ ~~576.2~~580.0°F
Measured reactor vessel average temperature rate/lag time constant	τ_3 ≥ ~~0~~10 secs
Measured reactor vessel ΔT lag time constant	τ_4 ≤ 6 secs
Measured reactor vessel average temperature lag time constant	τ_5 ≤ 2 secs

Specification 3.2.5 DNB Parameters

Parameter	Indicated Value
Reactor Coolant System Tavg	Tavg ≤ ~~580.0~~583.6°F(1)
Pressurizer Pressure	Pressure ≥ ~~2215~~2218 psia(2)
Reactor Coolant System Total Flow Rate	Flow ≥ ~~267,400~~ 267,300 gpm(3)

(1) The Reactor Coolant System (RCS) T_{avg} value includes allowances for rod control operation and verification via control board indication.

(2) The pressurizer pressure value includes allowances for pressurizer pressure control operation and verification via control board indication.

(3) The RCS total flow rate includes allowances for normalization of the cold leg elbow taps with a beginning of cycle precision RCS flow calorimetric measurement and verification on a periodic basis via control board indication.

Replace with Insert C1-3.

Provided for Information Only.

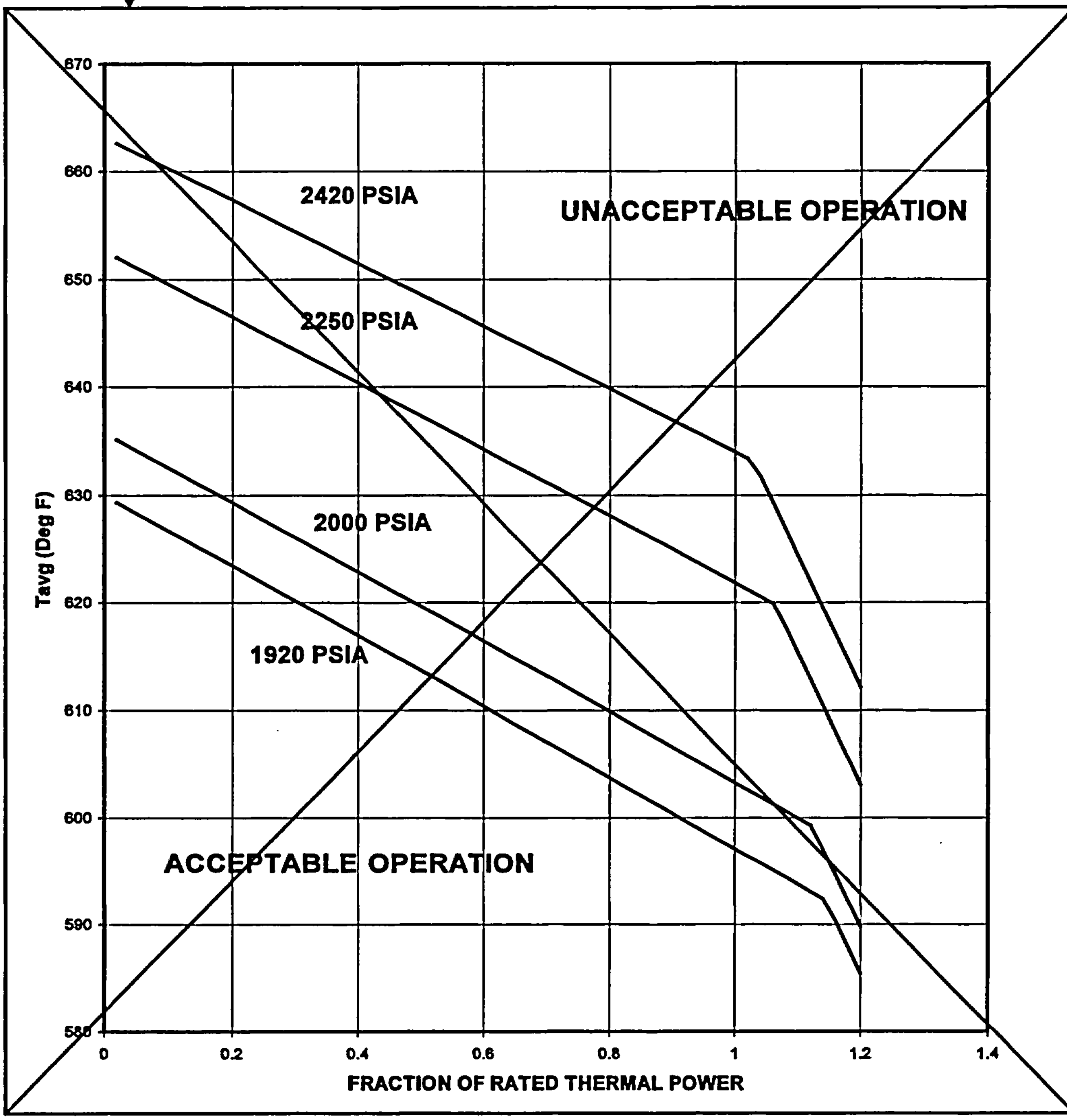
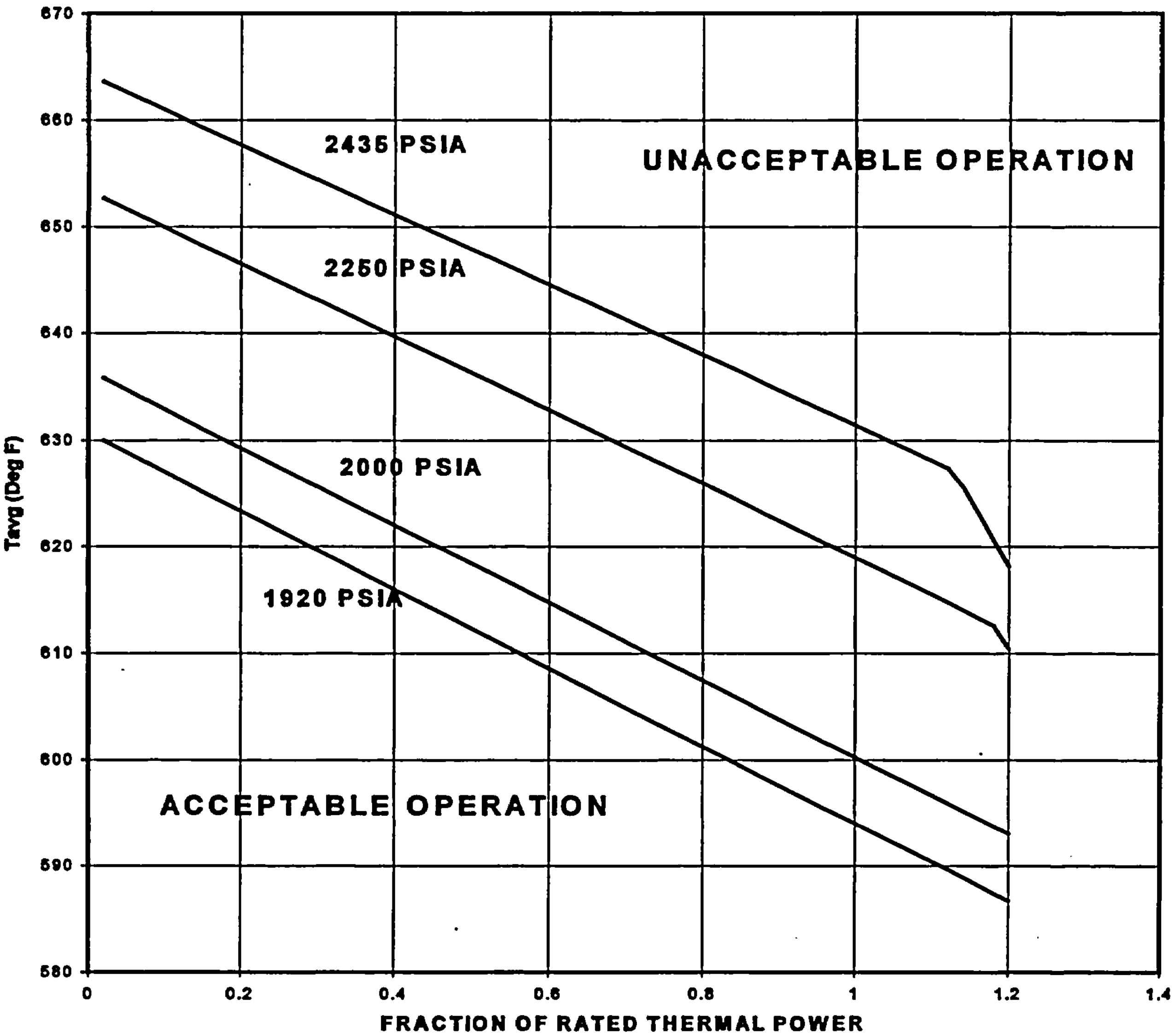


Figure 4.1-5
REACTOR CORE SAFETY LIMIT
THREE LOOP OPERATION
(Technical Specification Safety Limit 2.1.1)

Provided for Information Only.

Insert C1-3.



Provided for Information Only.

PRESSURE AND TEMPERATURE LIMITS REPORT

MATERIAL PROPERTY BASIS
LIMITING MATERIAL: INTERMEDIATE & LOWER SHELL PLATE
LIMITING ART VALUES AT ~~22~~ 21 EFPY: 1/4T, 233°F
3/4T, 196°F

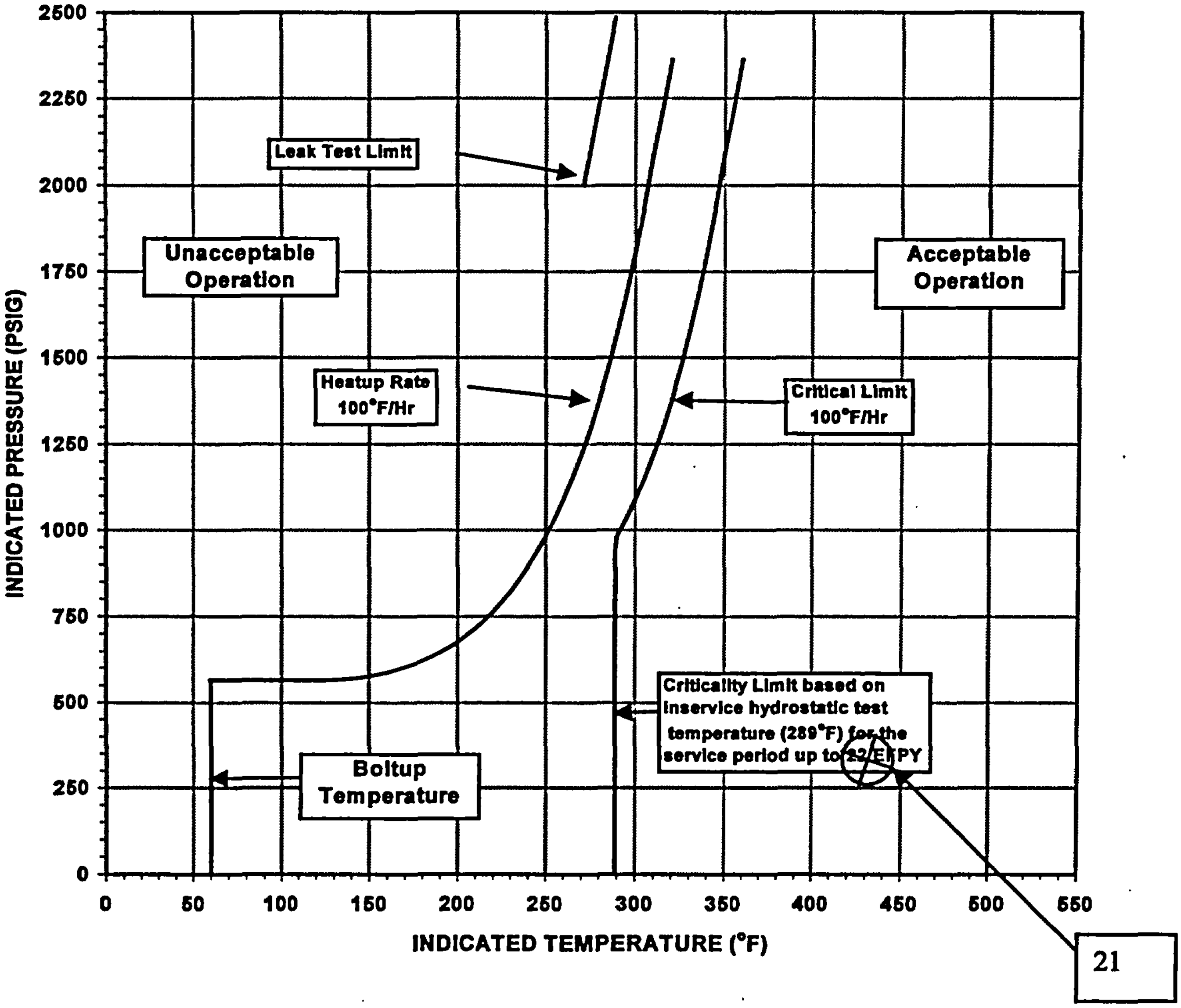


Figure 4.2-1
Reactor Coolant System Heatup
Limitations Applicable for the First ~~22~~ 21 EFPY (TS 3.4.9.1)

MATERIAL PROPERTY BASIS

LIMITING MATERIAL: INTERMEDIATE & LOWER SHELL PLATE

LIMITING ART VALUES AT ~~22~~ 21 EFPY: 1/4T, 233°F

3/4T, 196°F

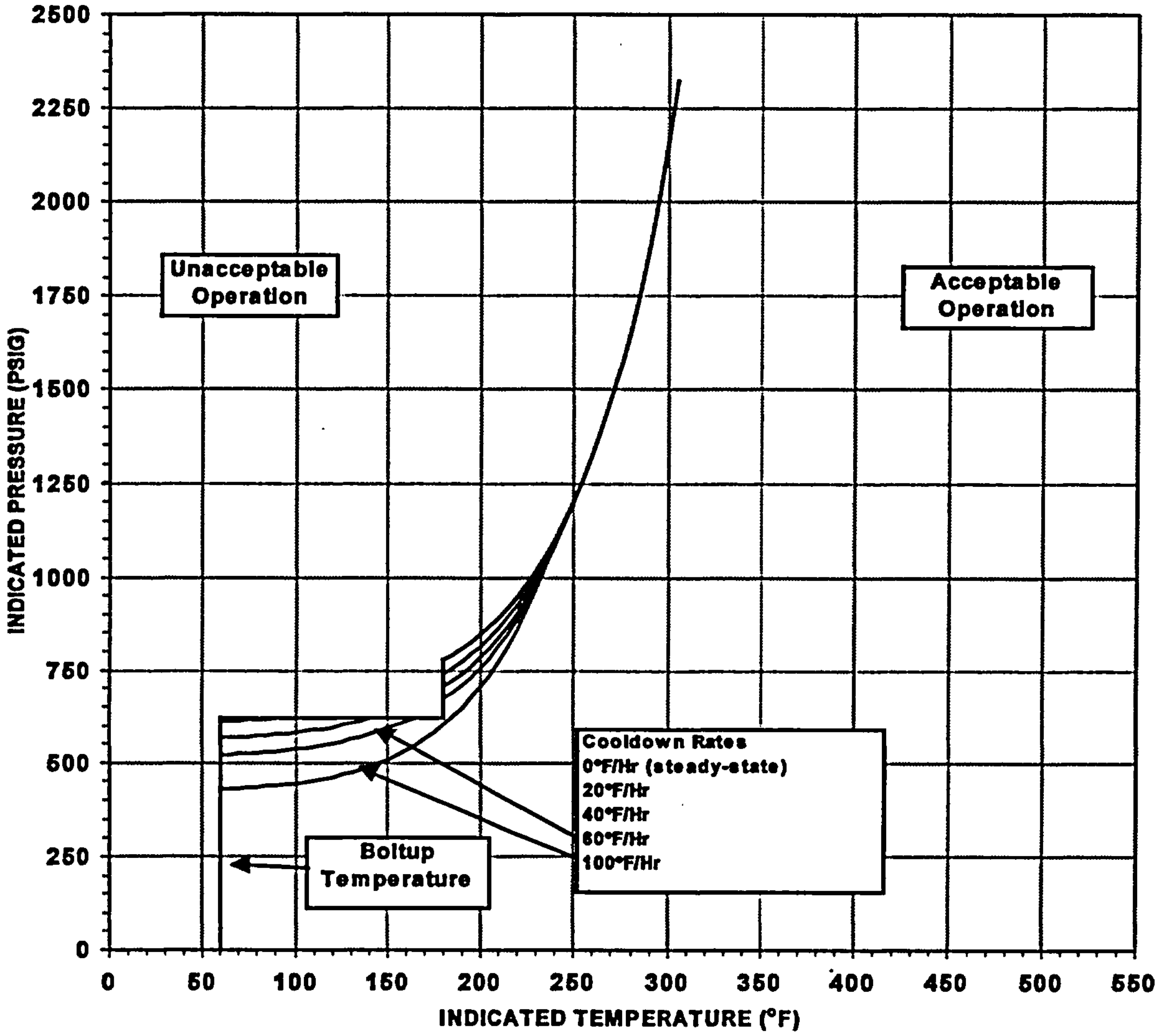


Figure 4.2-2
Reactor Coolant System Cooldown
Limitations Applicable for the First ~~22~~ 21 EFPY (TS 3.4.9.1)

6.5 Snubbers

LICENSING REQUIREMENT

LR 6.5 All snubbers shall be OPERABLE. The only snubbers excluded from this requirement are those installed on non safety-related systems and then only if their failure or failure of the system on which they are installed, would have no adverse effect on any safety-related system.

APPLICABILITY: MODES 1, 2, 3 and 4. (MODES 5 and 6 for snubbers located on systems# required OPERABLE in those MODES).

ACTION:

With one or more snubbers inoperable, within 72 hours replace or restore the inoperable snubber(s) to OPERABLE status and perform an engineering evaluation per LRS 6.5.1.d on the supported component or declare the supported system inoperable and follow the appropriate ACTION statement for that system.

LICENSING REQUIREMENT SURVEILLANCES

LRS 6.5.1 Each snubber shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program and the requirements of Technical Specification Surveillance 4.0.5.

a. Inspection Types

As used in this LRS, "type of snubber" shall mean snubbers of the same design and manufacturer, irrespective of capacity.

b. Visual Inspections

Snubbers are categorized as inaccessible or accessible during reactor operation. Each of these categories (inaccessible and accessible) may be inspected independently according to the schedule determined by Table 6.5-1. The visual inspection interval for each type of snubber shall be determined based upon the criteria provided in Table 6.5-1 and the first inspection interval determined using this criteria shall be based upon the previous inspection interval as established by the requirements in effect before Technical Specification amendment 167.

These systems are defined as those portions or subsystems required to prevent releases in excess of 10 CFR ~~100~~ 50.67 limits.

B.3.8 LEADING EDGE FLOW METER

The Leading Edge Flow Meter (LEFM) is the preferred method of obtaining the daily calorimetric heat balance measurements. A properly operating LEFM provides superior measurement accuracy, and more reliable assurance that the reactor is being operated at a power level that is within the assumptions of the design basis accident analyses.

The LEFM system provides measurements of feedwater mass flow and temperature yielding a total power measurement uncertainty of better than ±0.6% RTP at full power. This is more accurate than the venturi-based flow instrumentation. However, the accuracy of the LEFM is only valid while the instrument is performing as designed. The on-line verification and self-diagnostic features of the LEFM provides the ability to assure that the instrument is performing as designed.

The Applicability Statement applies when performing calorimetric power measurements during MODE 1 operations at steady-state conditions above ~~2652 MWt~~98.6% of RTP. The Operating License limits the maximum steady state power to ~~2689 MWt~~100% of RTP, when calorimetric heat balance measurements are made daily using the LEFM.

If the LEFM is not OPERABLE during the interval between required calorimetric heat balance measurements, plant operation may continue at ≤ ~~2689 MWt~~98.6% of RTP steady-state, using the existing Nuclear Instrumentation System (NIS) indication until the next required performance of the daily power calorimetric surveillance is due.

If the LEFM remains inoperable at the time that the next required calorimetric heat balance measurement is due, plant operation may continue at ≤ ~~2652 MWt~~98.6% of RTP steady-state, by making calorimetric measurements using feedwater flow venturis and Resistance Temperature Detector (RTD) indications. The requirement to reduce power within one hour is based upon comparison to similar action statements in the technical specifications. The increase in likelihood that the NIS will need renormalizing after 25 hours compared to after 24 hours is considered negligible.

It is preferable that the daily heat balance calculations be made using the subroutine on the in-plant process computer (IPC). If the IPC is unavailable, a manual calculation that accounts for steam generator blowdown is acceptable, and may be performed in lieu of using the IPC.

Attachment C-2

Beaver Valley Power Station, Unit No. 2

Proposed Licensing Requirements Manual Changes

License Amendment Request No. 173

The following is a list of the affected pages:

Page	Pending LAR
1.0-3	
3.1-2	
3.1-4	
3.2-2	
3.2-3	190
3.2-4	
3.2-5	190
3.8-1	
3.10-2	
4.1-1	
4.1-2	
4.1-6	
4.1-7	
4.1-8	
4.1-9	
4.1-10	
4.2-6	
4.2-7	
4.2-8	
4.2-9	
4.2-10	
4.2-11	
6.5-1	
B.3-3	

1.0 GENERAL REQUIREMENTS

1.0.1 Definitions

The defined terms contained in the Technical Specifications Section 1.0, "Definitions" apply to the requirements contained in this manual. In the Licensing Requirements Manual (LRM), defined terms are shown in all capital letters, consistent with their use in the Technical Specifications.

1.0.1.a RATED THERMAL POWER

The value of RATED THERMAL POWER, as per Technical Specification Definition 1.3, is 2689 MWt.

1.0.2 Failure to meet a Licensing Requirement (LR) or Licensing Requirement Surveillance (LRS) in the LRM

When either a) the requirements of an LR are not met and the associated Actions are not met or an associated Action is not provided or b) when the requirements of an LRS are not met:

1. A condition report shall be written, and

2. The safety significance of the non-conforming condition shall be evaluated and appropriate corrective actions initiated as required by Appendix B of 10 CFR Part 50. The time frame for completion of the corrective actions shall be commensurate with the safety significance of the condition, consistent with the guidance of NRC Generic Letter 91-18.

Exceptions to this requirement are provided in Sections 1.1 and 1.2 of the LRM for such things as restoring equipment to OPERABLE status, and surveillance interval extensions.

1.0.3 Technical Specification Related Information

Other requirements specified in the LRM such as those contained in tables, reports, or figures (e.g., Instrumentation Response Times and COLR) are not associated with an LR or LRS. These requirements are contained in the LRM because they are referenced from within the Technical Specifications. The guidance in this manual for implementing LRs and LRSs does not apply to the LRM requirements referenced from within the Technical Specifications. The failure to meet LRM requirements referenced from within the Technical Specifications shall be controlled by the applicable Technical Specifications.

1.0.4 LRM Revisions

Modifications to the content of the LRM (including the Technical Specification related information discussed in 1.0.3 above) shall be processed in accordance with 1/2-ADM-2206. 1/2-ADM-2206 provides guidance for changing the LRM in accordance with the provisions of 10 CFR 50.59.

Provided for Information Only.

TABLE 3.1-1
REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

	FUNCTIONAL UNIT	RESPONSE TIME
1.	Manual Reactor Trip	NOT APPLICABLE
2.	Power Range, Neutron Flux	$\leq$ 0.5 seconds(1)
3.	Power Range, Neutron Flux, High Positive Rate	NOT APPLICABLE
4.	~~Power Range, Neutron Flux, High Negative Rate~~DELETED	~~$\leq$ 0.5 seconds(1)~~
5.	Intermediate Range, Neutron Flux	NOT APPLICABLE
6.	Source Range, Neutron Flux (Below P-10)	NOT APPLICABLE
7.	Overtemperature ΔT	Variable(1)(2)
8.	Overpower ΔT	Variable(1)(2)
9.	Pressurizer Pressure -- Low (Above P-7)	$\leq$ 2.0 seconds
10.	Pressurizer Pressure -- High	$\leq$ 2.0 seconds
11.	Pressurizer Water Level -- High (Above P-7)	NOT APPLICABLE
12.	Loss of Flow - Single Loop (Above P-8)	$\leq$ 1.0 seconds
13.	Loss of Flow - Two Loop (Above P-7 and below P-8)	$\leq$ 1.0 seconds
14.	Steam Generator Water Level--Low-Low (Loop Stop Valves Open)	$\leq$ 2.0 seconds
15.	DELETED	
16.	Undervoltage-Reactor Coolant Pumps (Above P-7)	$\leq$ 1.5 seconds
17.	Underfrequency-Reactor Coolant Pumps (Above P-7)	$\leq$ 0.9 seconds

Provided for Information Only.

TABLE 3.1-1.a
Overtemperature Delta-T & Overpower Delta-T Response Times

This table represents the maximum allowable plant testing, electronic response time acceptance criteria based on measured RTD response time. All listed values are in seconds.

To use this table, take the slowest measured RTD response time in a loop, round up to the nearest 1/10 second, and obtain the corresponding acceptance criteria.

Replace with Insert C2-1.

~~Time Response Testing*~~		~~Time Response Testing*~~	
~~RTD Time Response~~	~~Acceptance Criteria~~	~~RTD Time Response~~	~~Acceptance Criteria~~
~~2.0~~	~~2.112~~		
~~2.1~~	~~2.103~~	~~4.6~~	~~1.567~~
~~2.2~~	~~2.094~~	~~4.7~~	~~1.533~~
~~2.3~~	~~2.085~~	~~4.8~~	~~1.500~~
~~2.4~~	~~2.076~~	~~4.9~~	~~1.466~~
~~2.5~~	~~2.068~~	~~5.0~~	~~1.432~~
~~2.6~~	~~2.059~~	~~5.1~~	~~1.398~~
~~2.7~~	~~2.050~~	~~5.2~~	~~1.364~~
~~2.8~~	~~2.041~~	~~5.3~~	~~1.330~~
~~2.9~~	~~2.032~~	~~5.4~~	~~1.295~~
~~3.0~~	~~2.023~~	~~5.5~~	~~1.260~~
~~3.1~~	~~2.014~~	~~5.6~~	~~1.225~~
~~3.2~~	~~2.005~~	~~5.7~~	~~1.189~~
~~3.3~~	~~1.986~~	~~5.8~~	~~1.155~~
~~3.4~~	~~1.953~~	~~5.9~~	~~1.120~~
~~3.5~~	~~1.922~~	~~6.0~~	~~1.085~~
~~3.6~~	~~1.890~~	~~6.1~~	~~1.049~~
~~3.7~~	~~1.859~~	~~6.2~~	~~1.014~~
~~3.8~~	~~1.827~~	~~6.3~~	~~0.973~~
~~3.9~~	~~1.795~~	~~6.4~~	~~0.936~~
~~4.0~~	~~1.763~~	~~6.5~~	~~0.899~~
~~4.1~~	~~1.731~~	~~6.6~~	~~0.862~~
~~4.2~~	~~1.698~~	~~6.7~~	~~0.825~~
~~4.3~~	~~1.666~~	~~6.8~~	~~0.787~~
~~4.4~~	~~1.633~~	~~6.9~~	~~0.749~~
~~4.5~~	~~1.600~~	~~7.0~~	~~0.711~~

~~*All values are in seconds.~~

Provided for Information Only.

Insert C2-1.

RTD Time Response	Final Accept. Criteria Overtemperature $\Delta T - T_{avg}$ Input	Final Accept. Criteria Overpower $\Delta T - T_{avg}$ Input	Final Accept. Criteria Measured $\Delta T - \Delta T$ Input
2.0	2.862	2.643	9.883
2.1	2.840	2.625	9.777
2.2	2.818	2.609	9.672
2.3	2.796	2.592	9.568
2.4	2.775	2.575	9.464
2.5	2.754	2.559	9.362
2.6	2.733	2.543	9.260
2.7	2.713	2.527	9.159
2.8	2.693	2.512	9.059
2.9	2.673	2.497	8.960
3.0	2.654	2.481	8.861
3.1	2.634	2.467	8.763
3.2	2.615	2.452	8.666
3.3	2.596	2.438	8.569
3.4	2.578	2.423	8.473
3.5	2.559	2.409	8.378
3.6	2.541	2.395	8.283
3.7	2.523	2.382	8.189
3.8	2.505	2.368	8.096
3.9	2.487	2.354	8.003
4.0	2.469	2.341	7.911
4.1	2.452	2.328	7.819
4.2	2.434	2.315	7.728
4.3	2.417	2.302	7.637
4.4	2.400	2.289	7.547
4.5	2.383	2.276	7.457
4.6	2.366	2.264	7.367
4.7	2.349	2.251	7.279
4.8	2.333	2.239	7.190
4.9	2.316	2.226	7.102
5.0	2.300	2.214	7.014
5.1	2.283	2.202	6.927
5.2	2.267	2.190	6.840
5.3	2.250	2.178	6.754
5.4	2.235	2.166	6.668
5.5	2.218	2.154	6.582
5.6	2.202	2.143	6.497
5.7	2.187	2.131	6.412
5.8	2.171	2.120	6.327
5.9	2.156	2.108	6.242
6.0	2.140	2.097	6.158
6.1	2.040	1.997	6.058
6.2	1.940	1.897	5.958
6.3	1.840	1.797	5.858
6.4	1.740	1.697	5.758
6.5	1.640	1.597	5.658
6.6	1.540	1.497	5.558
6.7	1.440	1.397	5.458
6.8	1.340	1.297	5.358
6.9	1.240	1.197	5.258
7.0	1.140	1.097	5.158

The following are the response time acceptance criteria for the pressurizer pressure and neutron flux input to the Overtemperature ΔT function:

Pressurizer pressure input: ≤ 2.0 seconds.
Neutron detector input (for f(ΔI) penalty): ≤ 2.0 seconds.

All of the channel time responses noted above for the Overtemperature ΔT, Overpower ΔT, and measured ΔT channels are for all portions of the channel downstream of the RTD output (i.e., includes channel electronics, trip breaker, and rod gripper release). The time responses are based on all channel setpoints (i.e., all gains and time constants) implemented as per the Licensing Requirements Manual values.

TABLE 3.2-1
ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION			RESPONSE TIME IN SECONDS
1.	Manual		
	a.	Safety Injection (ECCS)	Not Applicable
		Feedwater Isolation	Not Applicable
		Reactor Trip (SI)	Not Applicable
		Containment Isolation-Phase "A"	Not Applicable
		Containment Vent and Purge Isolation	Not Applicable
		Auxiliary Feedwater Pumps	Not Applicable
		Service Water System	Not Applicable
	b.	Containment Quench Spray Pumps	Not Applicable
		Containment Quench Spray Valves	Not Applicable
		Containment Isolation-Phase "B"	Not Applicable
	c.	Containment Isolation-Phase "A"	Not Applicable
	d.	Control Room Ventilation Isolation	Not Applicable
2.	Containment Pressure-High		
	a.	Safety Injection (ECCS)	≤ 27.0[3]
	b.	Reactor Trip (from SI)	≤ ~~2.0~~3.0
	c.	Feedwater Isolation	≤ 7.0[6]
	d.	Containment Isolation-Phase "A"	≤ 61.5[9]/115.5[10]
	e.	Auxiliary Feedwater Pumps	≤ 60.0
	f.	Service Water System	≤ 72.5[7]/181.5[8]

This page contains changes associated with LAR 190.

Provided for Information Only.

TABLE 3.2-1 (Continued)
ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION		RESPONSE TIME IN SECONDS
3.	Pressurizer Pressure-Low	
a.	Safety Injection (ECCS)	≤ 17.0[11]/27.0[3]/27.0[4]
b.	Reactor Trip (from SI)	≤ ~~2.0~~3.0
c.	Feedwater Isolation	≤ 7.0[6]
d.	Containment Isolation-Phase "A"	≤ 61.0[9]/115.0[10]
e.	Auxiliary Feedwater Pumps	≤ 60.0
f.	Service Water System	≤ 72.0[7]/181.0[8]
4.	Steam Line Pressure-Low	
a.	Safety Injection (ECCS)	≤ 37.0[5]/27.0[4]
b.	Reactor Trip (from SI)	≤ ~~2.0~~3.0
c.	Feedwater Isolation	≤ 7.0[6]
d.	Containment Isolation-Phase "A"	≤ 61.0[9]/115.0[10]
e.	Auxiliary Feedwater Pumps	≤ 60.0
f.	Service Water System	≤ 72.0[7]/181.0[8]
g.	Steam Line Isolation	≤ 7.0
5.	Containment Pressure--High-High	
a.	Containment Quench Spray	≤ 74.5[12]
b.	Containment Isolation-Phase "B"	Not Applicable
c.	Control Room Ventilation Isolation	≤ 22.0[9]/77.0[10]
6.	Steam Generator Water Level--High High	
a.	Turbine Trip	Not Applicable
b.	Feedwater Isolation	≤ 7.0[6]

TABLE 3.2-1 (Continued)
ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
7. Containment Pressure--Intermediate High-High	
a. Steam Line Isolation	≤ 7.0
8. Steamline Pressure Rate--High Negative	
a. Steamline Isolation	≤ 7.0
9. Loss of Power	
a. 4.16kv Emergency Bus Undervoltage (Loss of Voltage) (Trip Feeder)	≤ 1.3 sec.
b. 4.16kv and 480v Emergency Bus Undervoltage (Degraded voltage)	90 ± 5 sec.
10. Steam Generator Water Level-Low-Low	
a. Motor-driven Auxiliary Feedwater Pumps(1)	≤ 60.0
b. Turbine-driven Auxiliary Feedwater Pump(2)	≤ 60.0
11. Undervoltage RCP	
a. Turbine-driven Auxiliary Feedwater Pump	≤ 60.0
12. Trip of Main Feedwater Pumps	
a. Motor-driven Auxiliary Feedwater Pumps	≤ 60.0
~~13. Control Room High Radiation~~	
~~a. Control Room Ventilation Isolation~~	~~≤ 180.0(11)~~

TABLE 3.2-1 (Continued)
ENGINEERED SAFETY FEATURES RESPONSE TIMES
TABLE NOTATION

(1) on 2/3 in 2/3 Steam Generators

(2) on 2/3 any Steam Generator

(3) Diesel generator starting and sequence loading delays included. Response time limit includes opening of valves to establish SI path and attainment of discharge pressure for centrifugal charging pumps and Low Head Safety Injection pumps. Sequential transfer of charging pump suction from the volume control tank (VCT) to the refueling water storage tank (RWST) (RWST valves open, then VCT valves close) is not included.

(4) Diesel generator starting and sequence loading delays not included. Offsite power available. Response time limit includes opening of valves to establish SI path and attainment of discharge pressure for centrifugal charging pumps. Sequential transfer of charging pump suction from the volume control tank (VCT) to the refueling water storage tank (RWST) (RWST valves open, then VCT valves close) is included.

(5) Diesel generator starting and sequence loading delays included. Response time limit includes opening of valves to establish SI path and attainment of discharge pressure for centrifugal charging pumps. Sequential transfer of charging pump suction from the volume control tank (VCT) to the refueling water storage tank (RWST) (RWST valves open, then VCT valves close) is included.

(6) Feedwater system overall response time shall include verification of valve stroke times applicable to the feedwater containment isolation valves for Train A and the main feedwater regulating valves and bypass valves for Train B.

(7) Diesel generator starting and sequence loading delays included. Response time limit includes attainment of discharge pressure for service water pumps.

(8) Diesel generator starting and sequence loading delays not included. Response time limit only includes opening of valves to establish the flowpath to the diesel coolers.

(9) Diesel generator starting and sequence loading delays not included. Offsite power available. Response time limit includes operation of valves/dampers.

(10) Diesel generator starting and sequence loading delays included. Response time limit includes operation of valves/dampers.

(11) ~~Diesel generator starting and sequence loading delays not included. Response time limit includes operation of dampers.~~Diesel generator starting and sequence loading delays not included. Offsite power available. Response time limit includes opening of valves to establish SI path and attainment of discharge pressure for centrifugal charging pumps and Low Head Safety Injection pumps. Sequential transfer of charging pump suction from the volume control tank (VCT) to the refueling water storage tank (RWST) (RWST valves open, then VCT valves close) is not included.

(12) Diesel generator starting and sequence loading delays included. Response time does not include operation of the valves because Quench Spray valves are maintained open.

3.8 LEADING EDGE FLOW METER

LICENSING REQUIREMENT

LR 3.8 An OPERABLE Leading Edge Flow Meter (LEFM) shall be used in the performance of the daily calorimetric heat balance measurements to determine steady-state THERMAL POWER as required by Item 2.a of the Unit 2 Technical Specifications Table 4.3-1.

APPLICABILITY: MODE 1 when steady-state THERMAL POWER is > ~~2652 MWt~~98.6% of RTP.*

ACTION:

a. With the LEFM inoperable, restore to OPERABLE status prior to the next required daily calorimetric heat balance measurement, or

b. Within one hour, reduce steady-state THERMAL POWER to ≤ ~~2652 MWt~~98.6% of RTP.* Perform the calorimetric heat balance measurement using the feedwater flow venturis and Resistance Temperature Detector (RTD) indications. Maintain THERMAL POWER at ≤~~2652 MWt~~98.6% of RTP* steady state until the LEFM is restored to OPERABLE status and the calorimetric heat balance measurement has been performed using the LEFM.

LICENSING REQUIREMENT SURVEILLANCES

LRS 3.8.1 The LEFM shall be demonstrated to be OPERABLE at least once every 24 hours, by using the self-diagnostic features of the LEFM.

LRS 3.8.2 The LEFM shall be demonstrated to be OPERABLE at least once every 18 months, by performing the periodic maintenance and inspections recommended by the manufacturer.

*THERMAL POWER of 2652 MWt is equivalent to 2612 MWt when measured by the feedwater flow venturis.

TABLE 3.10-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

	FUNCTIONAL UNIT	NOMINAL TRIP SETPOINT
1.	Manual Reactor Trip	N.A.
2.	Power Range, Neutron Flux	
	a. High Setpoint	109% of RTP*
	b. Low Setpoint	25% RTP*
3.	Power Range, Neutron Flux High Positive Rate	5% of RTP* with a time constant ≥ 2 seconds
4.	~~Power Range, Neutron Flux High Negative Rate~~Deleted	~~5% of RTP* with a time constant ≥ 2 seconds~~
5.	Intermediate Range, Neutron Flux	25% RTP*
6.	Source Range, Neutron Flux	
	a. With Rod Withdrawal Capability	10^5 cps
	b. With All Rods Fully Inserted and Without Rod Withdrawal Capability	N.A.
7.	Overtemperature ΔT	See Technical Specification Table Notation (A) on Table 3.3-1
8.	Overpower ΔT	See Technical Specification Table Notation (B) on Table 3.3-1
9.	Pressurizer Pressure-Low	1945 psig**
10.	Pressurizer Pressure-High	2375 psig
11.	Pressurizer Water Level-High	92% of instrument span
12.	Loss of Flow	
	a. Single Loop	90% of indicated loop flow
	b. Two Loops	90% of indicated loop flow

* = RATED THERMAL POWER

** Time constants utilized in the lead-lag controller for Pressurizer Pressure-Low are ≥ 2 seconds for lead and ≤ 1 second for lag. Channel calibration shall ensure that these time constants are adjusted for those values.

4.1 CORE OPERATING LIMITS REPORT

This Core Operating Limits Report provides the cycle specific parameter limits developed in accordance with the NRC approved methodologies specified in Technical Specification Administrative Control 6.9.5.

<u>Specification 3.1.3.5 Shutdown Rod Insertion Limits</u>

The Shutdown rods shall be withdrawn to at least 225 steps.*

<u>Specification 3.1.3.6 Control Rod Insertion Limits</u>

Control Banks A and B shall be withdrawn to at least 225 steps.*

Control Banks C and D shall be limited in physical insertion as shown in Figure 4.1-1.*

<u>Specification 3.2.1 Axial Flux Difference</u>

NOTE: The target band is ±7% about the target flux from 0% to 100% RATED THERMAL POWER.

The indicated Axial Flux Difference:

a. Above 90% RATED THERMAL POWER shall be maintained within the ±7% target band about the target flux difference.

b. Between 50% and 90% RATED THERMAL POWER is within the limits shown on Figure 4.1-2.

c. Below 50% RATED THERMAL POWER may deviate outside the target band.

<u>Specification 3.2.2 $F_Q(Z)$ and F_{xy} Limits</u>

$$F_Q(Z) \le \frac{CF_Q}{P} * K(Z) \qquad \text{for } P > 0.5$$

$$F_Q(Z) \le \frac{CF_Q}{0.5} * K(Z) \qquad \text{for } P \le 0.5$$

Where: CF_Q = ~~2.3~~<u>2.4</u>

$$P = \frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$$

K(Z) = the function obtained from Figure 4.1-3.

*As indicated by the group demand counter

The F_{xy} limits [$F_{xy}(L)$] for RATED THERMAL POWER within specific core planes shall be:

$F_{xy}(L) = F_{xy}(RTP)\ (1 + PF_{XY} * (1-P))$

Where: For all core planes containing D-Bank:

$F_{xy}(RTP) \leq 1.71$

For unrodded core planes:

$F_{xy}(RTP) \leq 1.76$ from 1.8 ft. elevation to 2.3 ft. elevation

$F_{xy}(RTP) \leq 1.80$ from 2.3 ft. elevation to 3.7 ft. elevation

$F_{xy}(RTP) \leq 1.83$ from 3.7 ft. elevation to 5.8 ft. elevation

$F_{xy}(RTP) \leq 1.84$ from 5.8 ft. elevation to 7.4 ft. elevation

$F_{xy}(RTP) \leq 1.81$ from 7.4 ft. elevation to 9.0 ft. elevation

$F_{xy}(RTP) \leq 1.72$ from 9.0 ft. elevation to 10.2 ft. elevation

Provided as an example.

$PF_{xy} = 0.2$

$$P = \frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$$

Figure 4.1-4 provides the maximum total peaking factor times relative power ($F_Q^T * P_{rel}$) as a function of axial core height during normal core operation.

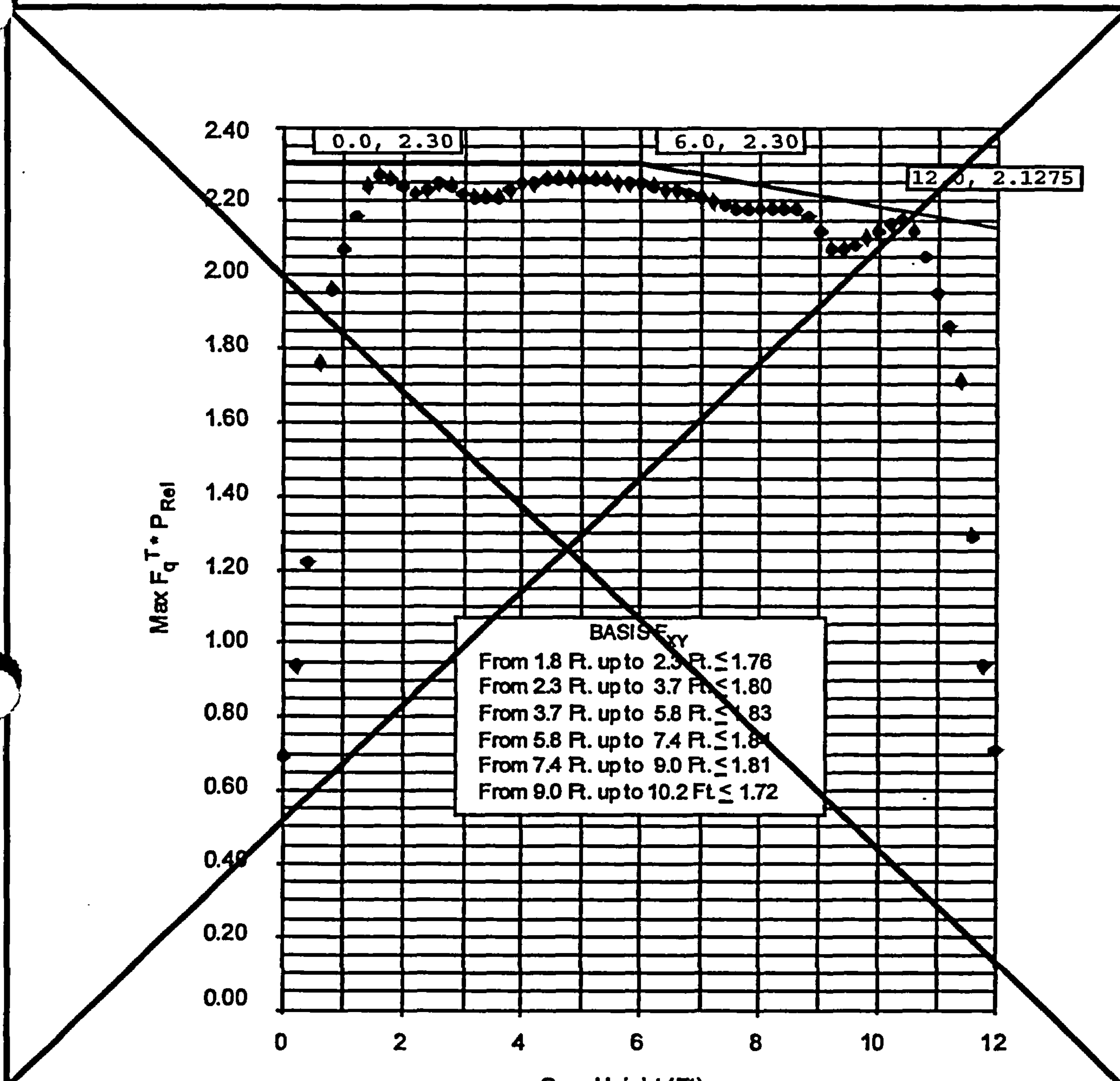
<u>Specification 3.2.3 $F^N_{\Delta H}$</u>

$$F^N_{\Delta H} \leq CF_{\Delta H} * (1 + PF_{\Delta H}\ (1 - P))$$

Where: $CF_{\Delta H} = 1.62$ <u>for Robust Fuel Assemblies and 1.456 for Vantage 5H Assemblies.</u>

$PF_{\Delta H} = 0.3$

$$P = \frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$$



Replace with Insert C2-2.

FIGURE 4.1-4

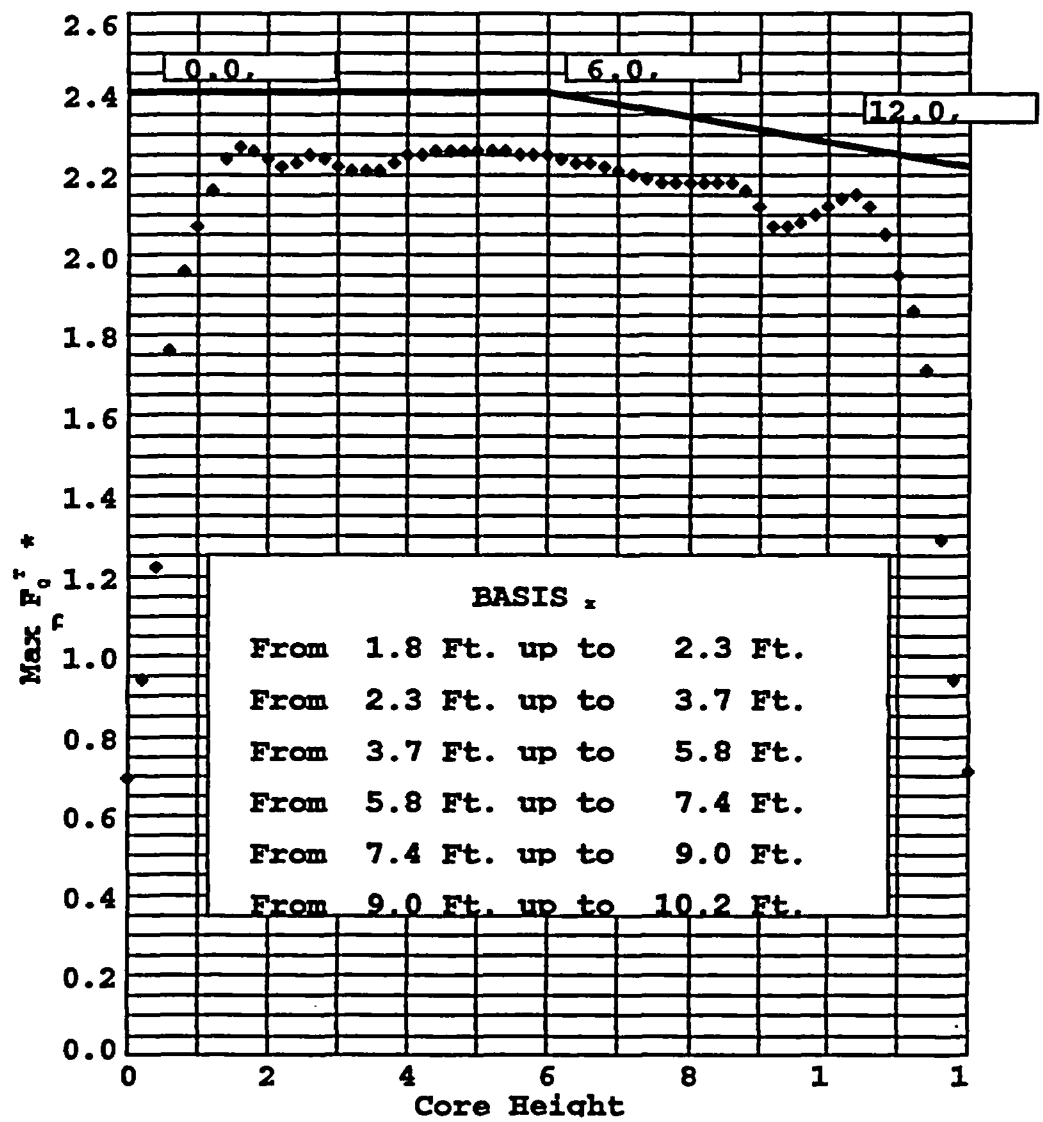
MAXIMUM (F_QT*Prel) VS. AXIAL CORE HEIGHT

DURING NORMAL OPERATION

Provided for Information Only.

Insert C2-2.

Provided as an example.



Specification 3.3.1.1 Reactor Trip System Instrumentation Setpoints, Table 3.3-1 Table Notations A and B

Overtemperature ΔT Setpoint Parameter Values:

Parameter	Value
Overtemperature ΔT reactor trip setpoint	K1 ≤ ~~1.311~~1.239
Overtemperature ΔT reactor trip setpoint Tavg coefficient	K2 ≥ 0.0183/°F
Overtemperature ΔT reactor trip setpoint pressure coefficient	K3 ≥ ~~0.00082~~0.001/psia
Tavg at RATED THERMAL POWER	T' ≤ ~~576.2~~580.0°F
Nominal pressurizer pressure	P' ≥ 2250 psia
Measured reactor vessel ΔT lead/lag time constants (* The response time is toggled off to meet the analysis value of zero.)	τ_1 ~~≥ 8~~ = 0 sec * τ_2 ~~≤ 3~~ = 0 sec *
Measured reactor vessel ΔT lag time constant	τ_3 ≤ ~~0~~6 sec
Measured reactor vessel average temperature lead/lag time constants	τ_4 ≥ 30 sec τ_5 ≤ 4 sec
Measured reactor vessel average temperature lag time constant	τ_6 ≤ ~~0~~2 sec

f (ΔI) is a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(i) For $q_t - q_b$ between -~~32~~48% and +~~11~~10%, $f_1(\Delta I) = 0$, where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER;

(ii) For each percent that the magnitude of $q_t - q_b$ exceeds -~~32~~48%, the ΔT Trip Setpoint shall be automatically reduced by ~~1.46~~4.67% of its value at RATED THERMAL POWER; and

(iii) For each percent that the magnitude of $q_t - q_b$ exceeds +~~11~~10%, the ΔT Trip Setpoint shall be automatically reduced by ~~1.56~~1.47% of its value at RATED THERMAL POWER.

Overpower ΔT Setpoint Parameter Values:

Parameter	Value
Overpower ΔT reactor trip setpoint	$K4 \leq 1.094$
Overpower ΔT reactor trip setpoint Tavg rate/lag coefficient	K5 ≥ ~~0.00~~0.02/°F for increasing average temperature K5 = 0/°F for decreasing average temperature
Overpower ΔT reactor trip setpoint Tavg heatup coefficient	K6 ≥ ~~0.0012~~0.0021/°F for T > T″ K6 = 0/°F for T ≤ T″
Tavg at RATED THERMAL POWER	T″ ≤ ~~576.2~~580.0°F
Measured reactor vessel ΔT lead/lag time constants (* The response time is toggled off to meet the analysis value of zero.)	$\tau_1 \geq$ ~~8~~ = 0 sec * $\tau_2 \leq$ ~~3~~ = 0 sec *
Measured reactor vessel ΔT lag time constant	$\tau_3 \leq$ ~~0~~ 6 sec
Measured reactor vessel average temperature lag time constant	$\tau_6 \leq$ ~~0~~ 2 sec
Measured reactor vessel average temperature rate/lag time constant	$\tau_7 \geq$ ~~0~~ 10 sec

Specification 3.2.5 DNB Parameters

Parameter	Indicated Value
Reactor Coolant System Tavg	Tavg ≤ ~~579.9~~583.6°F(1)
Pressurizer Pressure	Pressure ≥ 2214 psia(2)
Reactor Coolant System Total Flow Rate	Flow ≥ ~~267,200~~267,300 gpm(3)

(1) The Reactor Coolant System (RCS) T_{avg} value includes allowances for rod control operation and verification via control board indication.

(2) The pressurizer pressure value includes allowances for pressurizer pressure control operation and verification via control board indication.

(3) The RCS total flow rate includes allowances for normalization of the cold leg elbow taps with a beginning of cycle precision RCS flow calorimetric measurement and verification on a periodic basis via ~~plant process computer~~ control board indication. ~~If periodic verification of flow rate is performed via the process computer, the required flow value is ≥ 267,200 gpm.~~

Replace with Insert C2-3.

Provided for Information Only.

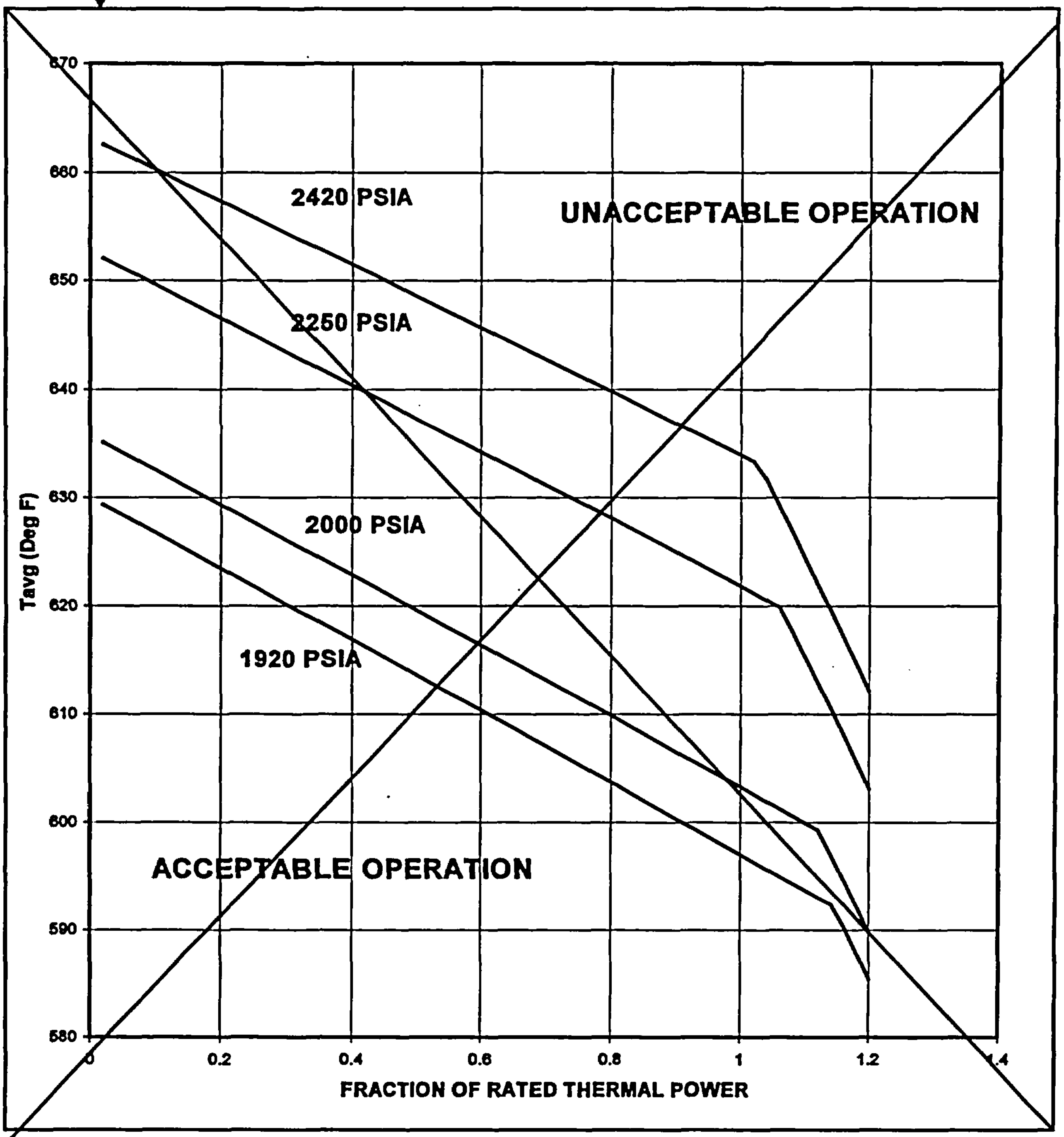


Figure 4.1-5
REACTOR CORE SAFETY LIMIT
THREE LOOP OPERATION
(Technical Specification Safety Limit 2.1.1)

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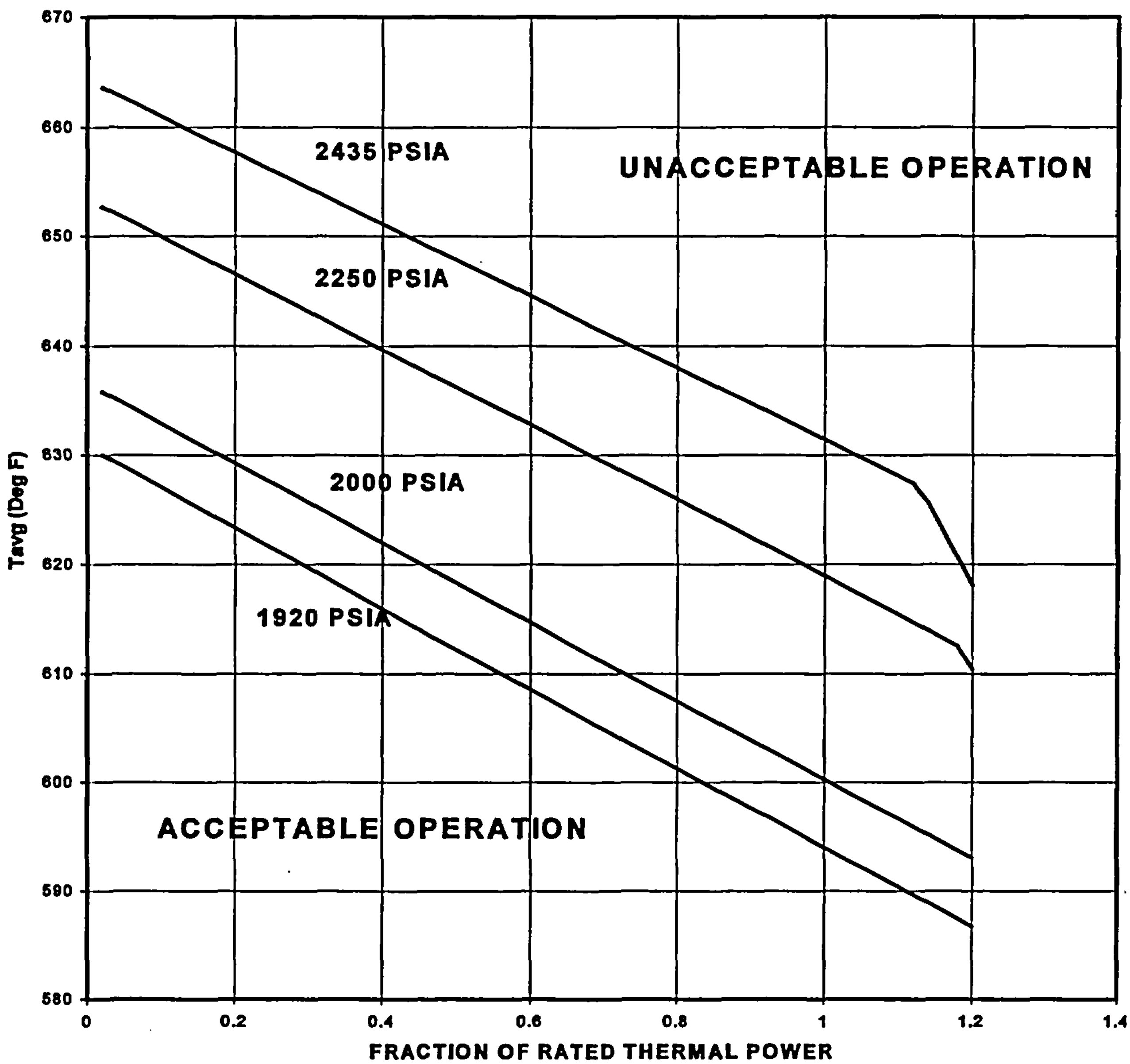
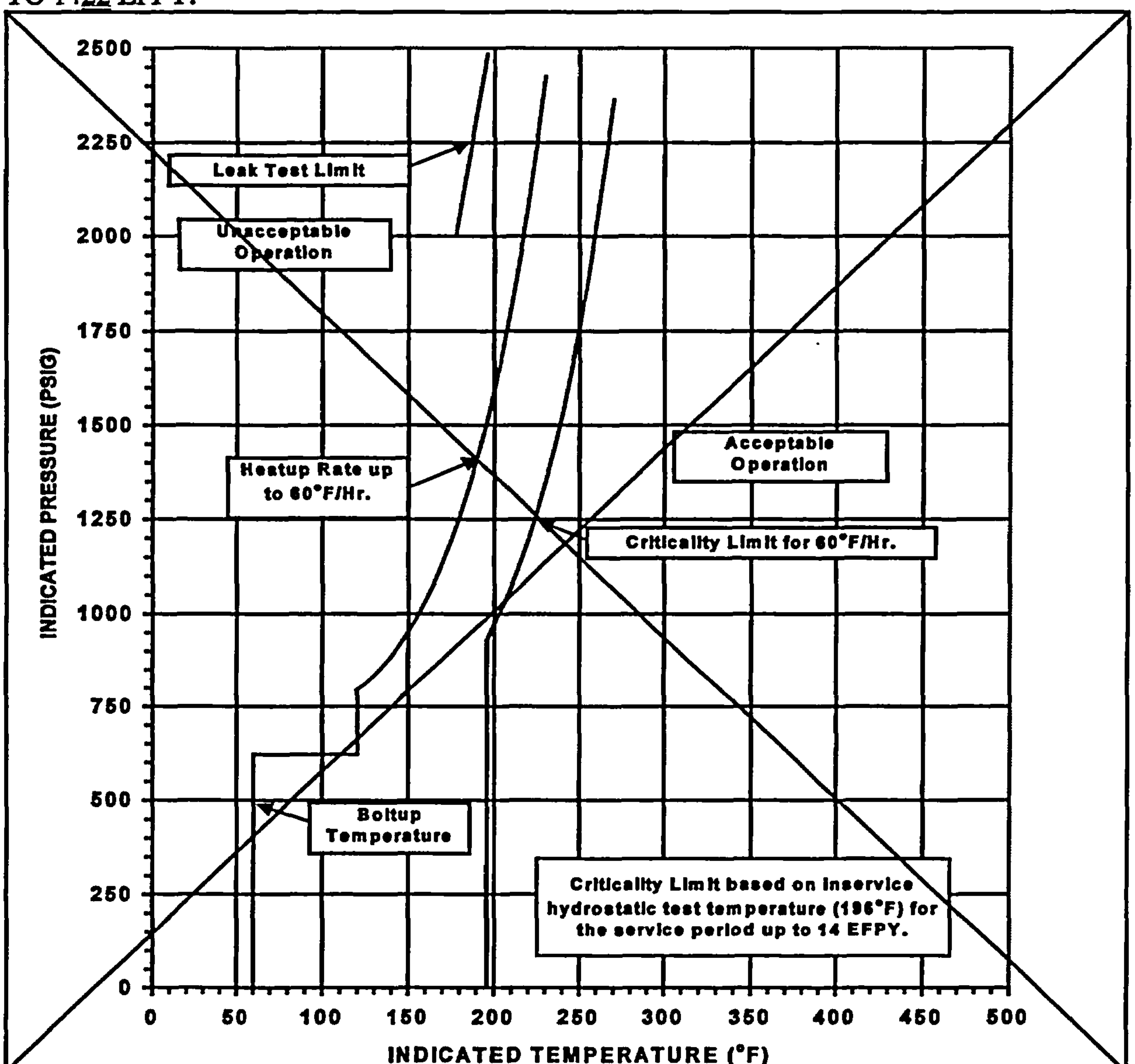
Insert C2-3.



MATERIAL PROPERTY BASIS

CONTROLLING MATERIAL:	INTERMEDIATE SHELL PLATE B9004-1
INITIAL RT_{NDT}:	60°F
RT_{NDT} AFTER ~~14~~22 EFPY:	1/4T, 140°F
	3/4T, ~~128~~129°F

CURVES APPLICABLE FOR HEATUP RATES UP TO 60°F/HR FOR THE SERVICE PERIOD UP TO ~~14~~22 EFPY.

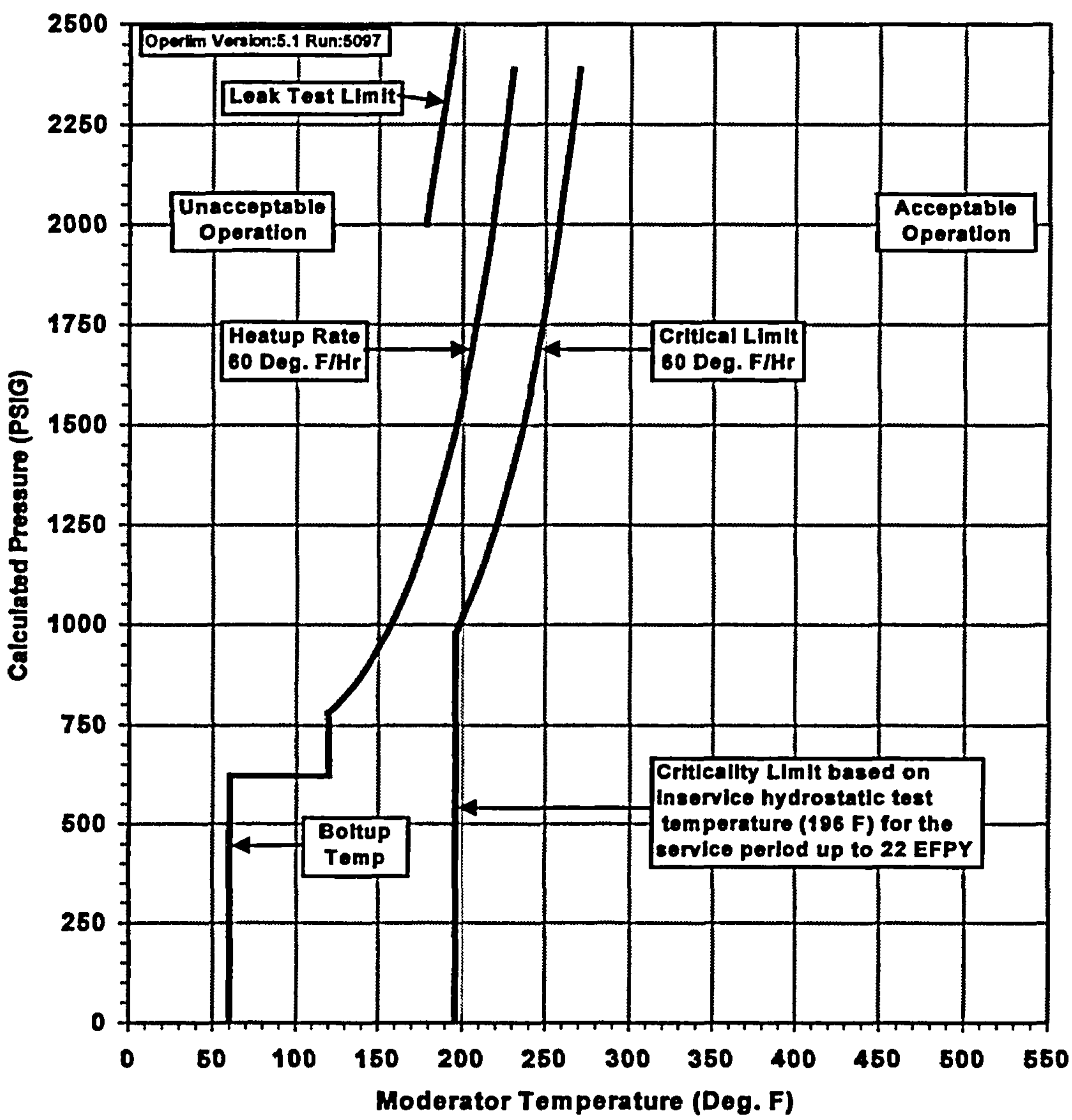


Replace with Insert C2-4.

Figure 4.2-1
Reactor Coolant System Heatup
Limitations Applicable for the First ~~14~~22 EFPY (TS 3.4.9.1)

Provided for Information Only.

Insert C2-4.

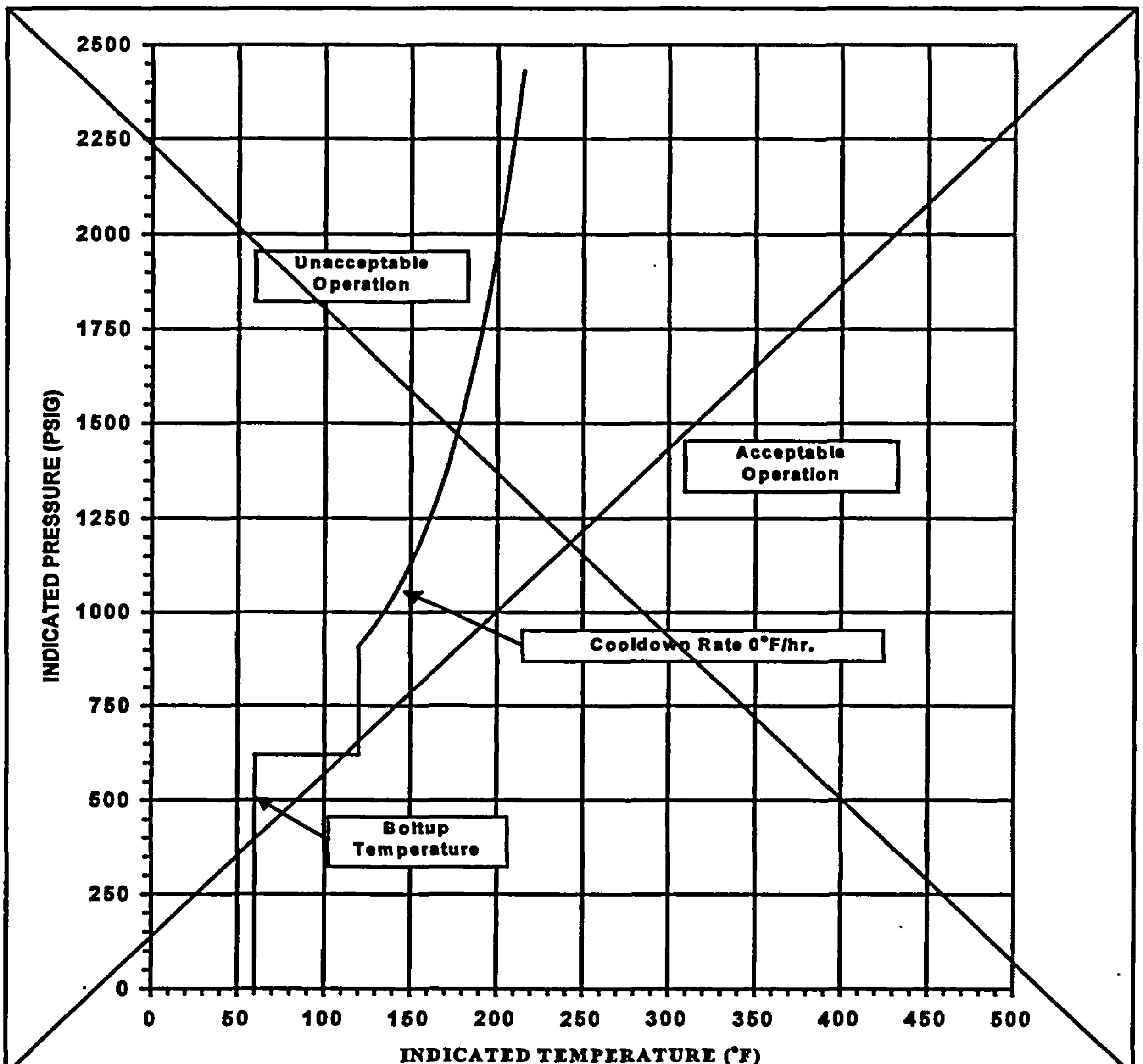


PRESSURE AND TEMPERATURE LIMITS REPORT

MATERIAL PROPERTY BASIS

CONTROLLING MATERIAL:	INTERMEDIATE SHELL PLATE B9004-1
INITIAL RT_{NDT}:	60°F
RT_{NDT} AFTER ~~14~~22 EFPY:	1/4T, 140°F
	3/4T, ~~128~~129°F

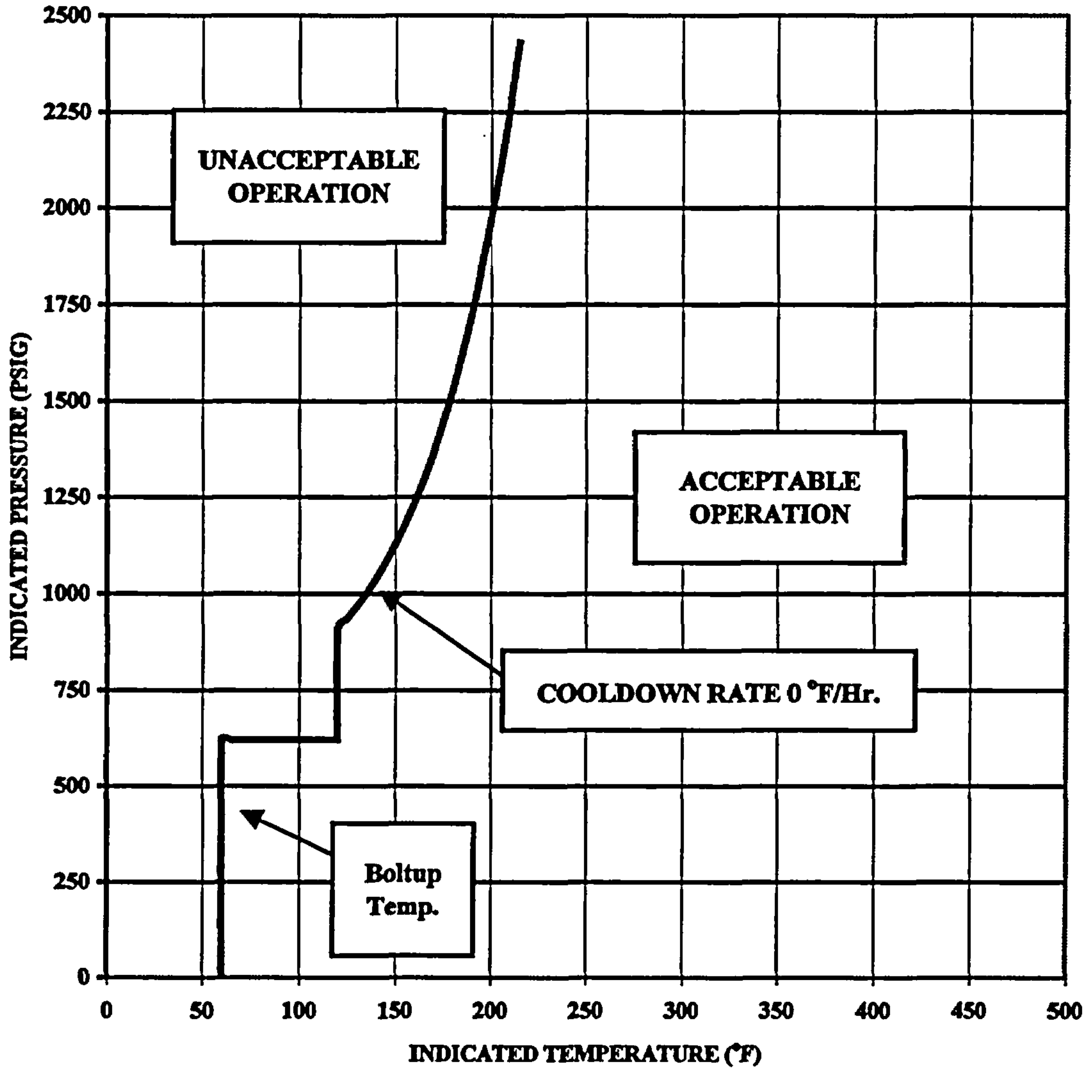
CURVE APPLICABLE FOR COOLDOWN RATES UP TO 0°F/HR FOR THE SERVICE PERIOD UP TO ~~14~~22 EFPY.



Replace with Insert C2-5.

Figure 4.2-2
Reactor Coolant System Cooldown (up to 0°F/Hr.)
Limitations Applicable for the First ~~14~~22 EFPY (TS 3.4.9.1)

Insert C2-5.



2500
2250
2000
1750
1500
1250
1000
750
500
250
0
INDICATED PRESSURE (PSIG)
UNACCEPTABLE OPERATION
ACCEPTABLE OPERATION
COOLDOWN RATE 0 °F/Hr.
Boltup Temp.
0
50
100
150
200
250
300
350
400
450
500
INDICATED TEMPERATURE (°F)

PRESSURE AND TEMPERATURE LIMITS REPORT

MATERIAL PROPERTY BASIS

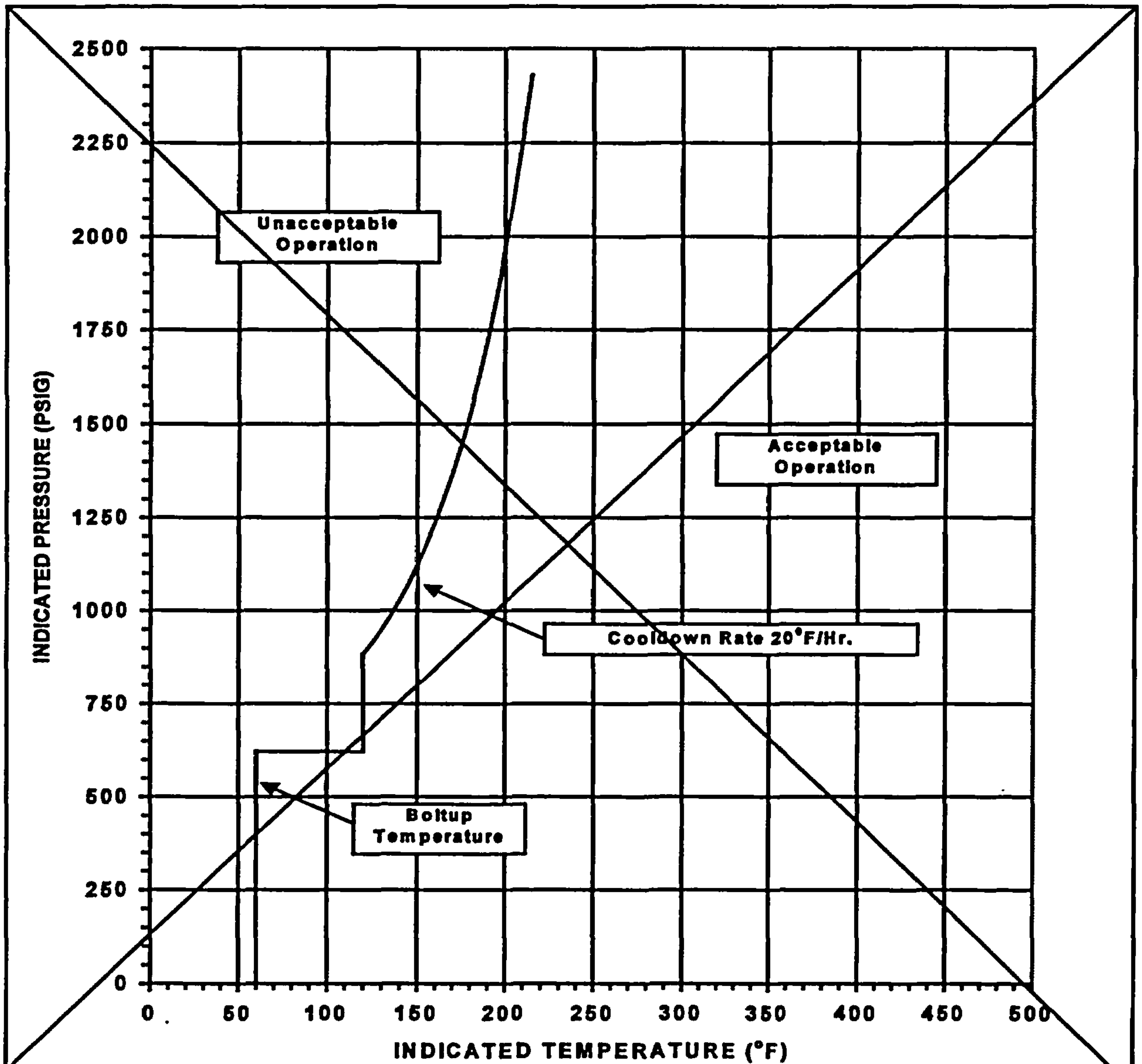
CONTROLLING MATERIAL: INTERMEDIATE SHELL PLATE B9004-1

INITIAL RT_{NDT}: 60°F

RT_{NDT} AFTER ~~14~~22 EFPY: 1/4T, 140°F

3/4T, ~~128~~129°F

CURVE APPLICABLE FOR COOLDOWN RATES UP TO 20°F/HR FOR THE SERVICE PERIOD UP TO ~~14~~22 EFPY.

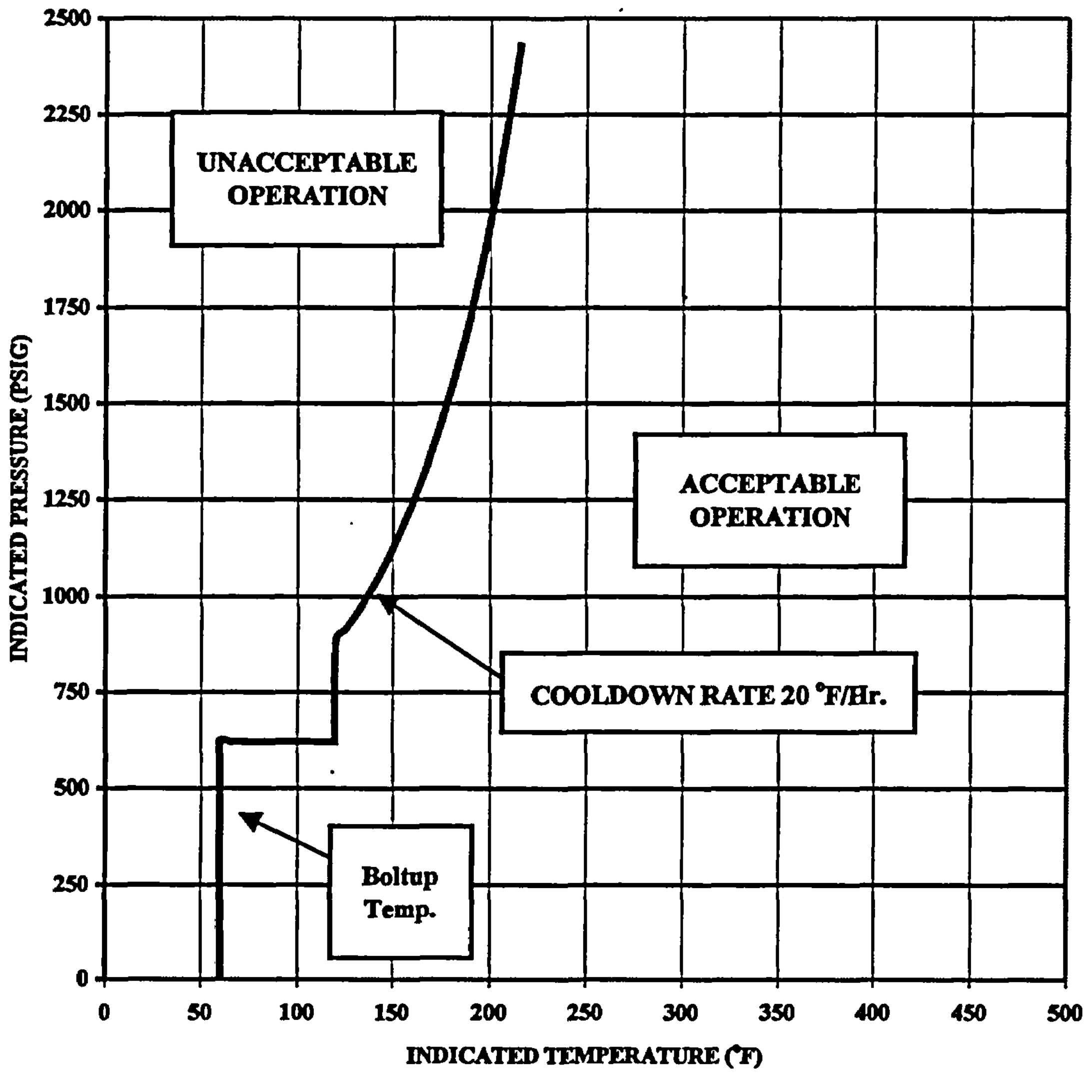


Replace with Insert C2-6.

Figure 4.2-3
Reactor Coolant System Cooldown (up to 20°F/Hr.)
Limitations Applicable for the First ~~14~~22 EFPY (TS 3.4.9.1)

Provided for Information Only.

Insert C2-6.



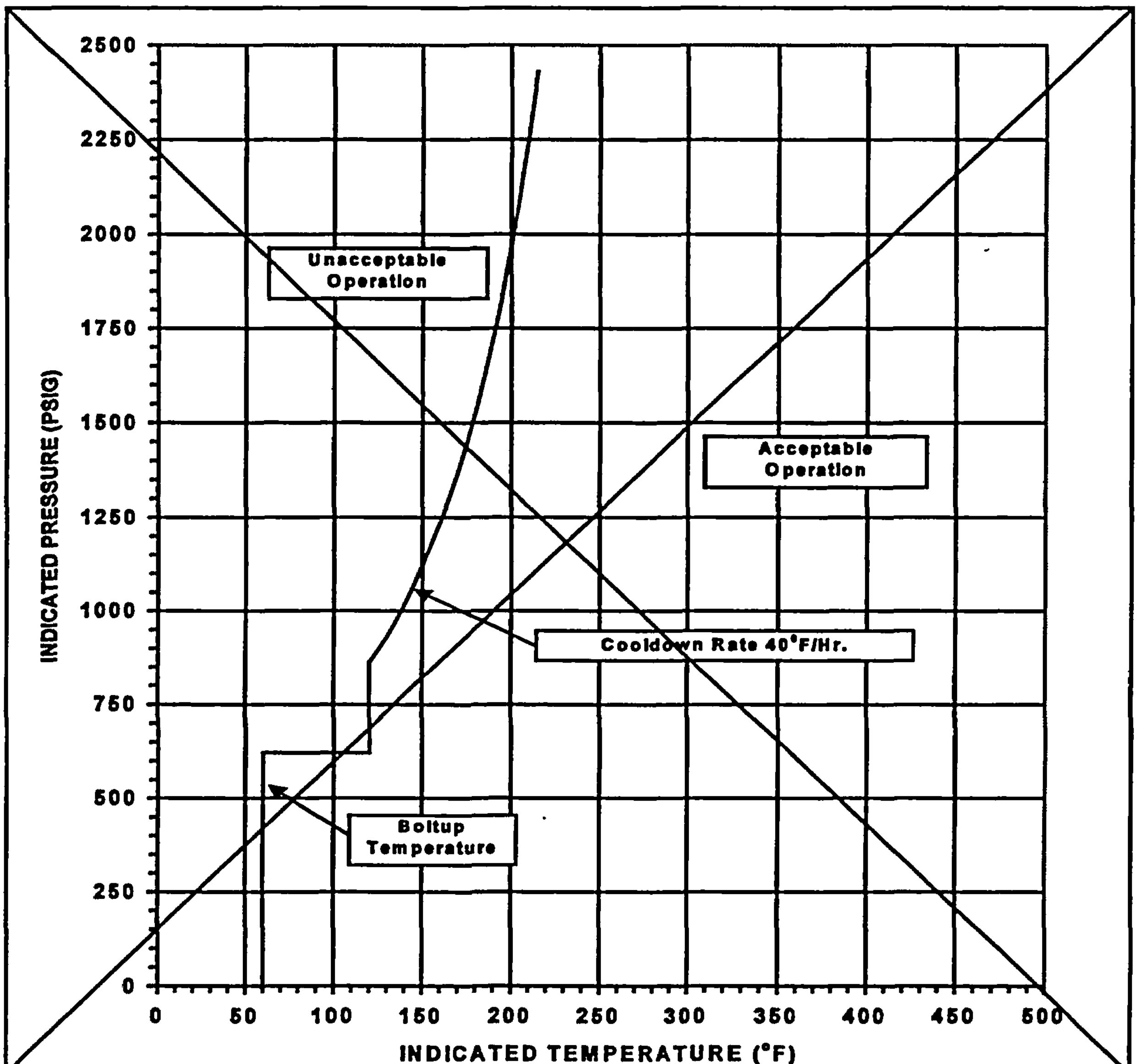
LICENSING REQUIREMENTS MANUAL

PRESSURE AND TEMPERATURE LIMITS REPORT

MATERIAL PROPERTY BASIS

CONTROLLING MATERIAL:	INTERMEDIATE SHELL PLATE B9004-1
INITIAL RT_{NDT}:	60°F
RT_{NDT} AFTER ~~14~~22 EFPY:	1/4T, 140°F
	3/4T, ~~128~~129°F

CURVE APPLICABLE FOR COOLDOWN RATES UP TO 40°F/HR FOR THE SERVICE PERIOD UP TO ~~14~~22 EFPY.

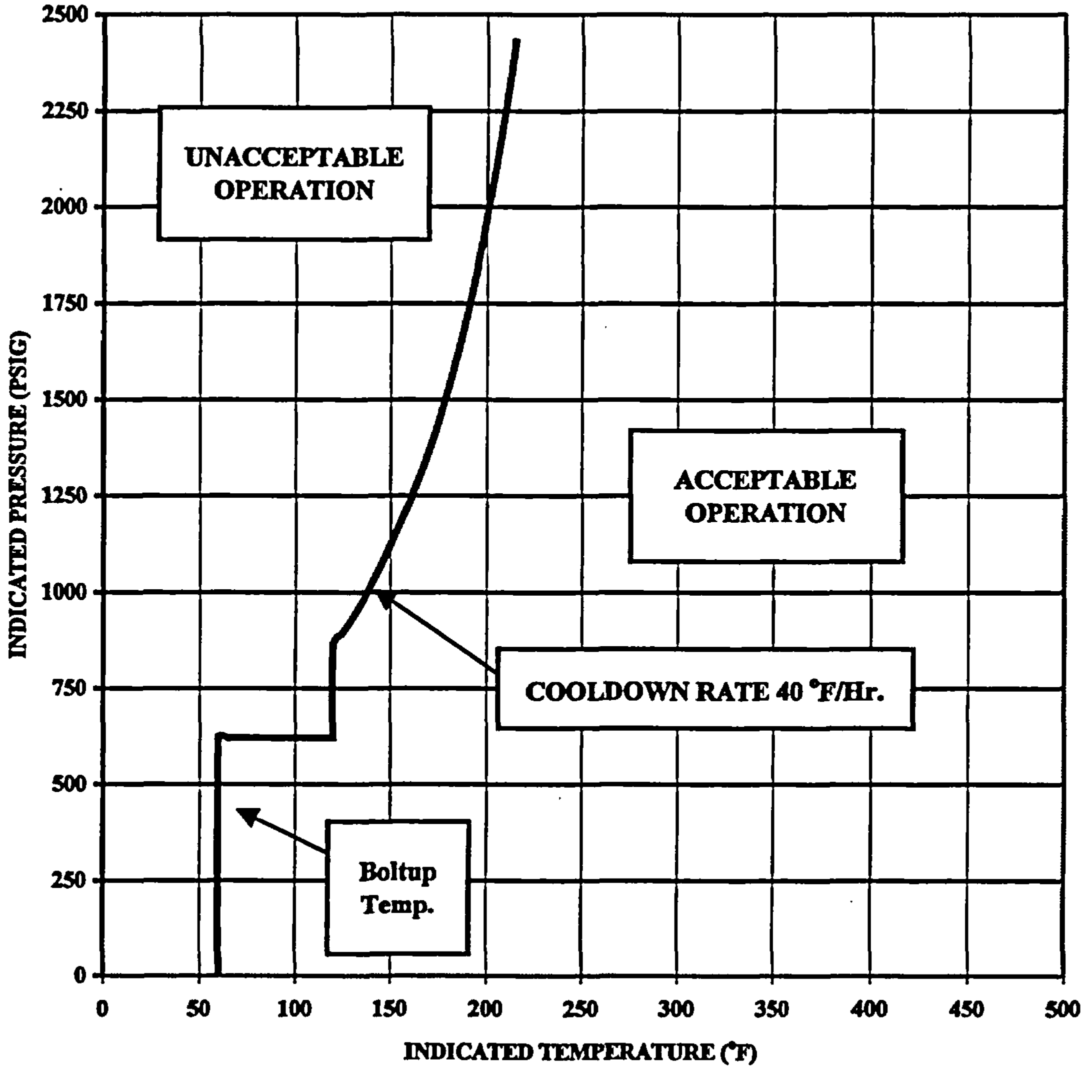


Replace with Insert C2-7.

Figure 4.2-4
Reactor Coolant System Cooldown (up to 40°F/Hr.)
Limitations Applicable for the First ~~14~~22 EFPY (TS 3.4.9.1)

Provided for Information Only.

Insert C2-7.



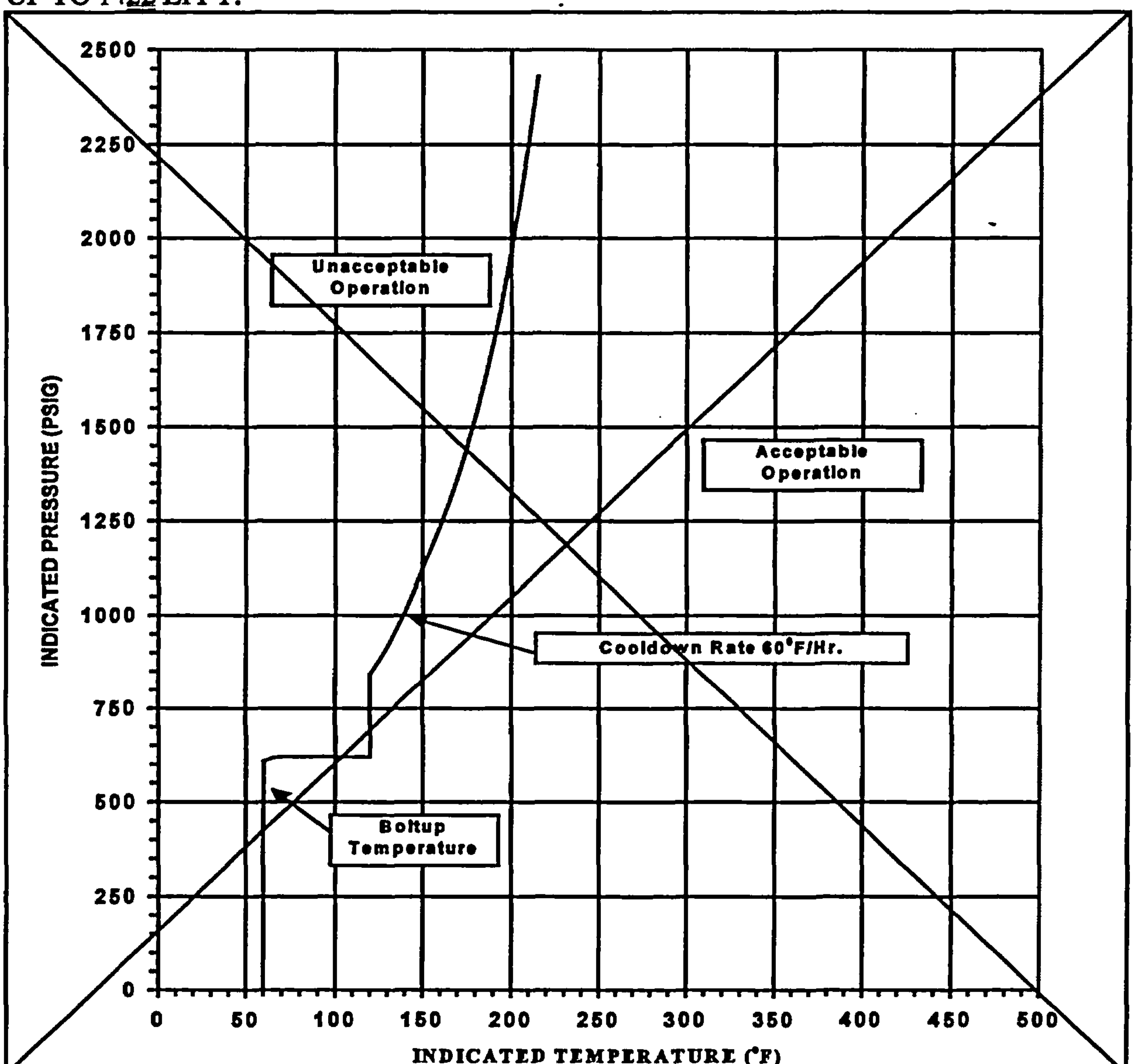
Provided for Information Only.

PRESSURE AND TEMPERATURE LIMITS REPORT

MATERIAL PROPERTY BASIS

CONTROLLING MATERIAL:	INTERMEDIATE SHELL PLATE B9004-1
INITIAL RT_{NDT}:	60°F
RT_{NDT} AFTER ~~14~~22 EFPY:	1/4T, 140°F
	3/4T, ~~128~~129°F

CURVE APPLICABLE FOR COOLDOWN RATES UP TO 60°F/HR FOR THE SERVICE PERIOD UP TO ~~14~~22 EFPY.

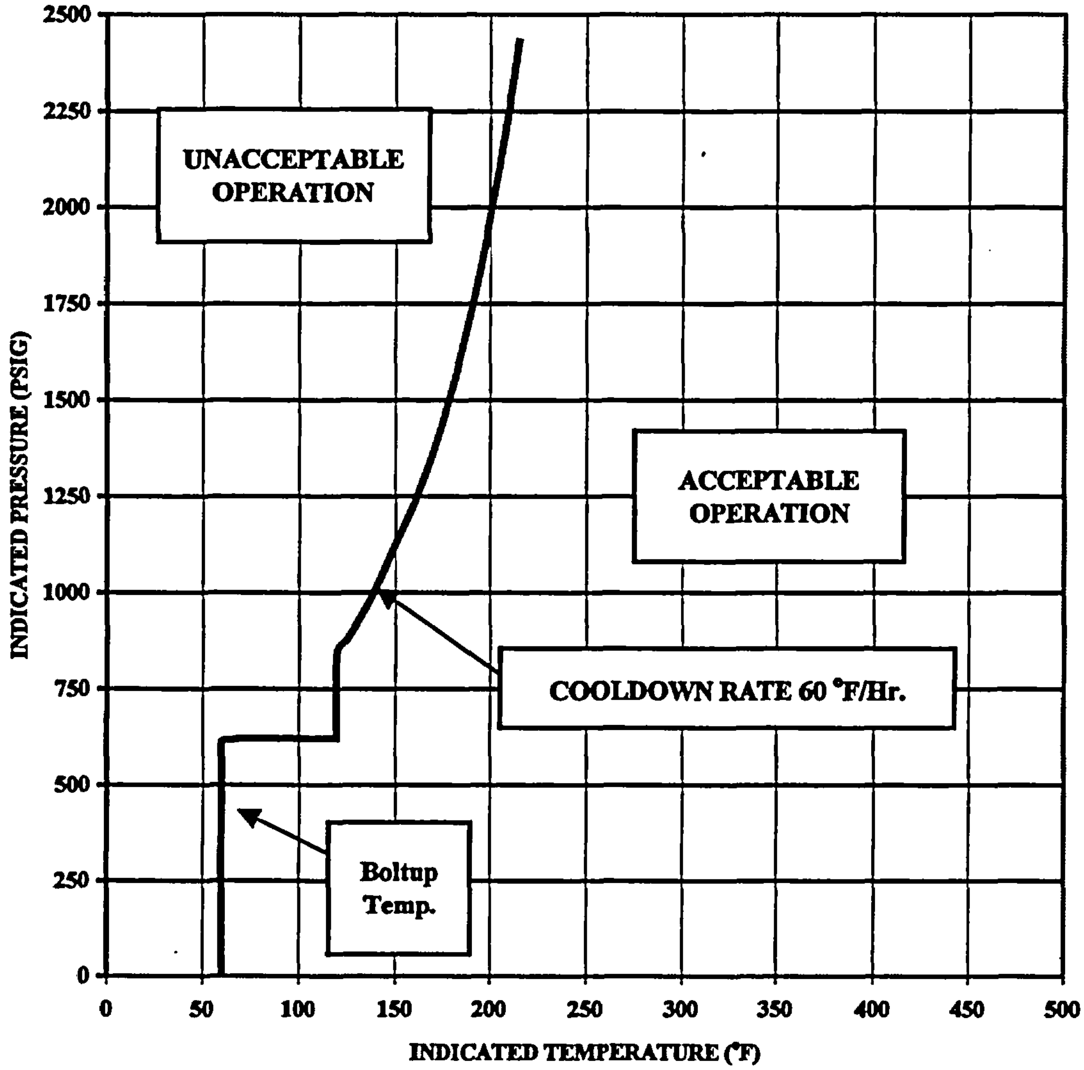


Replace with Insert C2-8.

Figure 4.2-5
Reactor Coolant System Cooldown (up to 60°F/Hr.)
Limitations Applicable for the First ~~14~~22 EFPY (TS 3.4.9.1)

Provided for Information Only.

Insert C2-8.



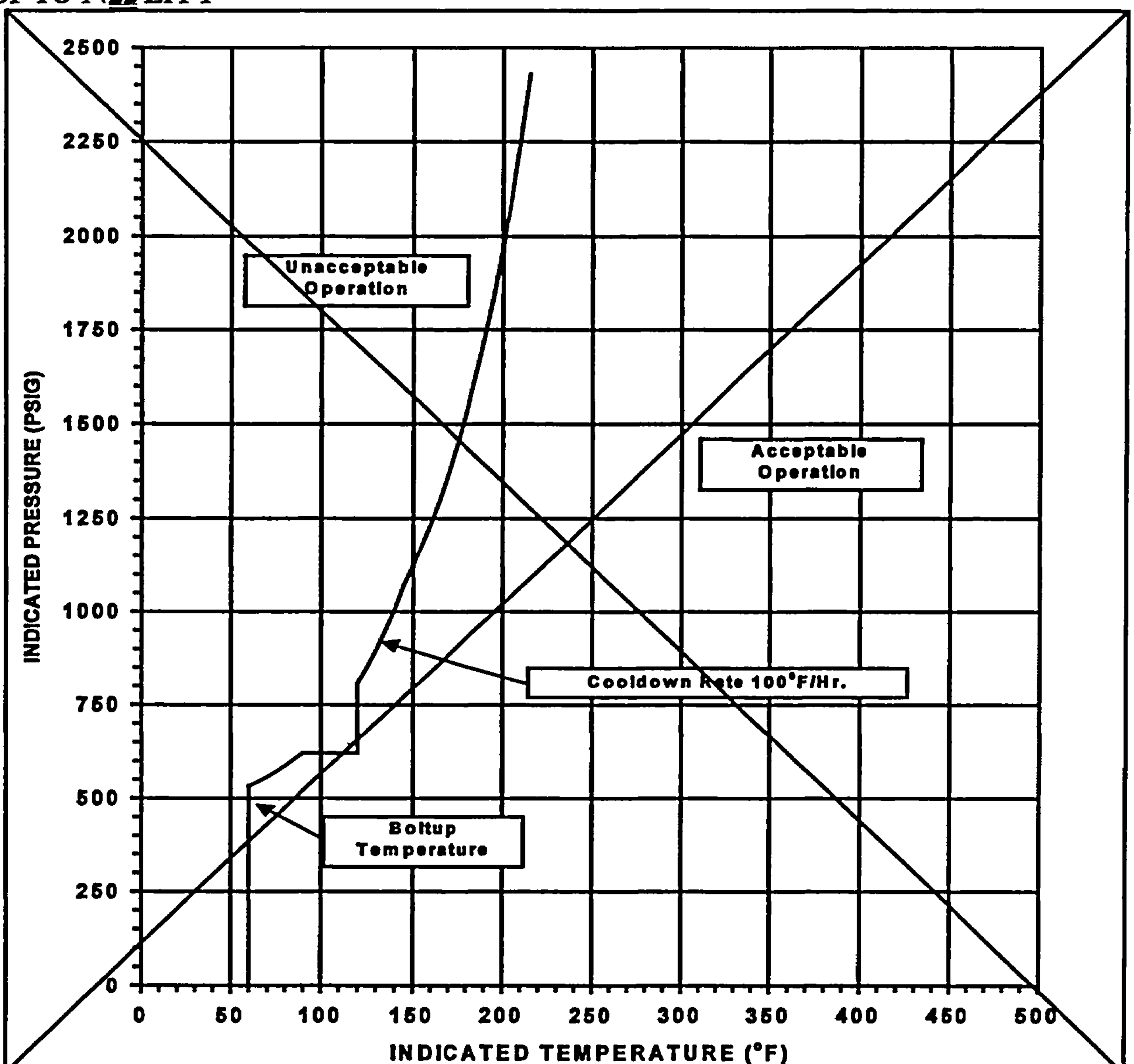
LICENSING REQUIREMENTS MANUAL

PRESSURE AND TEMPERATURE LIMITS REPORT

MATERIAL PROPERTY BASIS

CONTROLLING MATERIAL:	INTERMEDIATE SHELL PLATE B9004-1
INITIAL RT_{NDT}:	60°F
RT_{NDT} AFTER ~~14~~22 EFPY:	1/4T, 140°F
	3/4T, ~~128~~129°F

CURVE APPLICABLE FOR COOLDOWN RATES UP TO 100°F/HR FOR THE SERVICE PERIOD UP TO ~~14~~22 EFPY

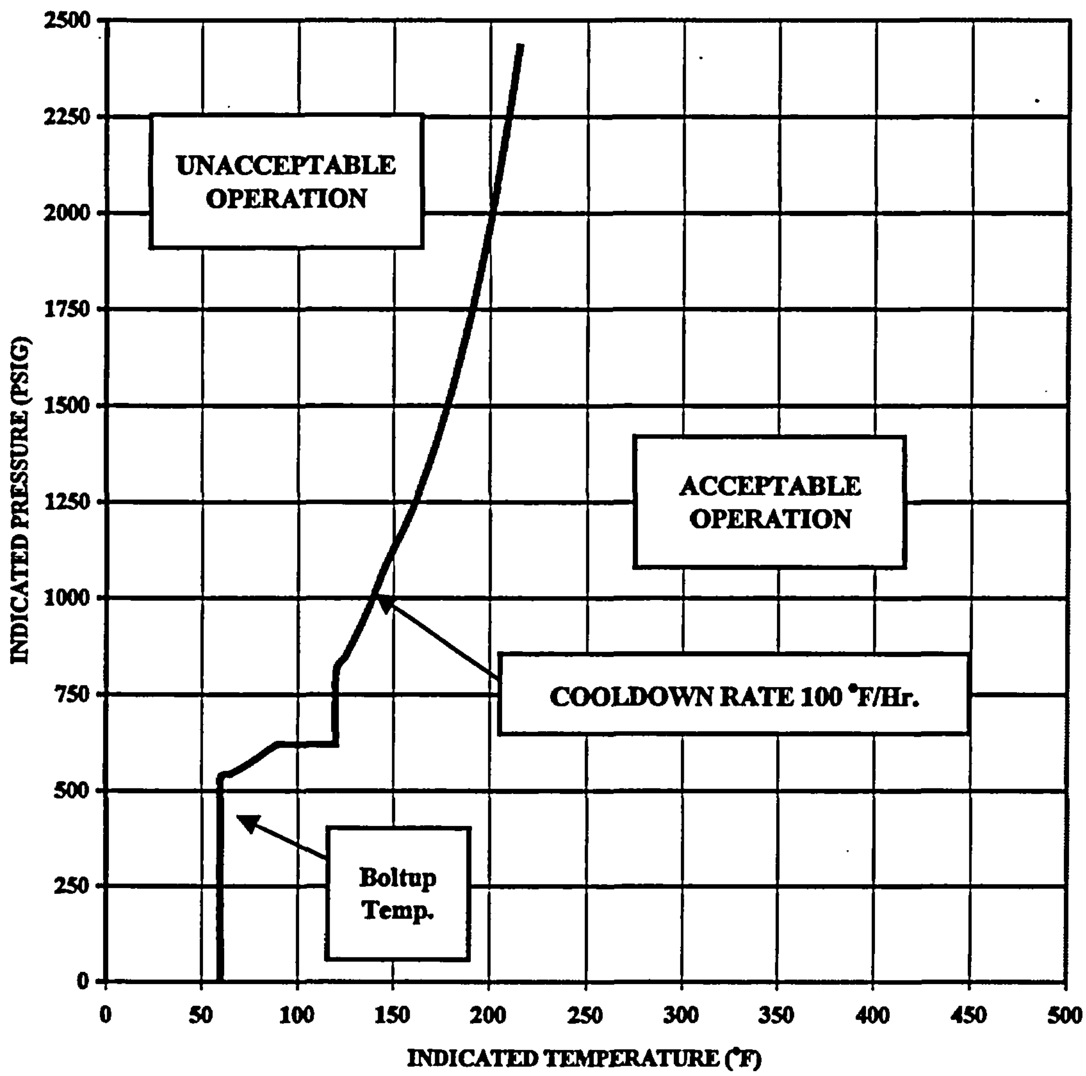


Replace with Insert C2-9.

Figure 4.2-6
Reactor Coolant System Cooldown (up to 100°F/Hr.)
Limitations Applicable for the First ~~14~~22 EFPY (TS 3.4.9.1)

Provided for Information Only.

Insert C2-9.



6.5 Snubbers

LICENSING REQUIREMENT

LR 6.5 All snubbers shall be OPERABLE. The only snubbers excluded from this requirement are those installed on non-safety-related systems and then only if their failure or failure of the system on which they are installed, would have no adverse effect on any safety-related system.

APPLICABILITY: MODES 1, 2, 3 and 4. (MODES 5 and 6 for snubbers located on systems* required OPERABLE in those MODES).

ACTION:

With one or more snubbers inoperable, within 72 hours replace or restore the inoperable snubber(s) to OPERABLE status and perform an engineering evaluation per LRS 6.5.1.d on the supported component or declare the supported system inoperable and follow the appropriate ACTION statement for that system.

LICENSING REQUIREMENT SURVEILLANCES

LRS 6.5.1 Each snubber shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program and the requirements of Technical Specification Surveillance 4.0.5.

a. Inspection Types

As used in this LRS, "type of snubber" shall mean snubbers of the same design and manufacturer, irrespective of capacity.

b. Visual Inspections

Snubbers are categorized as inaccessible or accessible during reactor operation. Each of these categories (inaccessible and accessible) may be inspected independently according to the schedule determined by Table 6.5-1. The visual inspection interval for each type of snubber shall be determined based upon the criteria provided in Table 6.5-1 and the first inspection interval determined using this criteria shall be based upon the previous inspection interval as established by the requirements in effect before Technical Specification amendment 49.

* These systems are defined as those portions or subsystems required to prevent releases in excess of 10 CFR ~~100~~ 50.67 limits.

B.3.8 LEADING EDGE FLOW METER (Continued)

The Applicability Statement applies when performing calorimetric power measurements during MODE 1 operations at steady-state conditions above ~~2652 MWt~~ 98.6% of RTP. The Operating License limits the maximum steady state power to ~~2689 MWt~~ 100% of RTP when calorimetric heat balance measurements are made daily using the LEFM.

If the LEFM is not OPERABLE during the interval between required calorimetric heat balance measurements, plant operation may continue at ≤ 2689 MWt steady-state, using the existing Nuclear Instrumentation System (NIS) indication until the next required performance of the daily power calorimetric surveillance is due.

If the LEFM remains inoperable at the time that the next required calorimetric heat balance measurement is due, plant operation may continue at ≤ ~~2652 MWt~~ 98.6% of RTP steady-state, by making calorimetric measurements using feedwater flow venturis and Resistance Temperature Detector (RTD) indications. The requirement to reduce power within one hour is based upon comparison to similar action statements in the technical specifications. The increase in likelihood that the NIS will need renormalizing after 25 hours compared to after 24 hours is considered negligible. A Note, designated by "*", is added to the Licensing Requirement to denote a difference between power measurements obtained when using the feedwater flow venturis and the LEFM. An indication of 2652 MWt from the LEFM is equivalent to an indication of 2612 MWt from the feedwater flow venturis.

It is preferable that the daily heat balance calculations be made using the subroutine on the plant computer system (PCS). If the PCS is unavailable, a manual calculation that accounts for steam generator blowdown is acceptable, and may be performed in lieu of using the PCS.

This surveillance is performed every 24 hours when power is above 15%. The NIS excore power range channel indications are renormalized if they are not found to be within ±2% of the calorimetric measurement. This ±2% requirement for renormalization is distinct from the allowance for calorimetric uncertainty, and these allowances are handled as independent contributions to determine the maximum power assumed in design basis accident analyses.

The plant may then be run for the next 24-hour period using this normalized NIS indication. Although calorimetric power indication may be monitored continuously, it is not required to be consulted again until the required daily calorimetric comparisons of NIS indication are performed.

The surveillance requirement to perform planned maintenance and inspections every 18 months is based upon the manufacturer's recommendations, and is consistent with the surveillance intervals specified for similar electronic apparatus.

Additional guidance for determining steady-state THERMAL POWER is taken from the NRC Inspection Manual; Inspection Procedure 61706; C/N 86-036, 07/14/1986; "Core Thermal Power Evaluation"; step 03.02.d, and is described in the BVPS Operating Manual.

Attachment D

Beaver Valley Power Station, Unit Nos. 1 and 2

Commitment Summary

License Amendment Request Nos. 302 (Unit 1) and 173 (Unit 2)

Commitment List

The following table identifies those actions committed to by FirstEnergy Nuclear Operating Company (FENOC) for Beaver Valley Power Station (BVPS) Unit Nos. 1 and 2 in this document. Any other actions discussed in the submittal represent intended or planned actions by FENOC. They are described only as information and are not regulatory commitments. Please notify Mr. Henry L Hegrat, Supervisor, Licensing on (330) 315-6944 of any questions regarding this document or associated regulatory commitments.

COMMITMENT	REFERENCE	DUE DATE
1. Incorporate the specific analyses required by WCAP-11394-P-A into the Core Reload Safety Analysis for each BVPS unit.	Enclosure 1 Section 4.1.3	Prior to or concurrent with EPU amendment implementation.
2. Implement LAR 317/190 (Containment Conversion), including plant modification commitments.	Enclosure 2 Section 1.1.2	Prior to or concurrent with EPU amendment implementation.
3. Implement LAR 318/191 (BELOCA).	Enclosure 2 Section 1.1.2	Prior to or concurrent with EPU amendment implementation.
4. Replace the Unit 1 steam generators with Westinghouse Model 54F Replacement Steam Generators, including replacement of level transmitters.	Enclosure 2 Sections 1.1.2, 4.7.1 and 9.25	Prior to EPU amendment implementation.
5. Modify the charging pumps by replacing rotating assemblies and extending the pump runout limit.	Enclosure 2 Sections 1.1.2, 9.2.3.4 and 9.4.1	Prior to EPU amendment implementation.
6. Modify the main feedwater flow control valve internals.	Enclosure 2 Section 3.1.5.3	Prior to power level increase.

Commitment List

COMMITMENT	REFERENCE	DUE DATE
7. Replace or modify the Unit 1 OPΔT and OTΔT instrumentation to incorporate lead/lag filters that accommodate the EPU time constants.	Enclosure 2 Sections 3.2.1, 5.3.1 and 9.25	Prior to EPU amendment implementation.
8. Modify the Unit 2 steam generators by removing tubes requiring preventative action from service.	Enclosure 2 Section 4.7.2.3	Prior to EPU amendment implementation.
9. Resolve the BVPS Unit 1 steam generator tube rupture event single failure issue by further analysis or by making a plant modification.	Enclosure 2 Section 5.4	Prior to or concurrent with BVPS Unit 1 EPU amendment implementation.
10. Replace the main steam flow and main feedwater flow transmitters.	Enclosure 2 Section 9.25	Prior to power level increase.
11. Update operating procedures and conduct operator training.	Enclosure 2 Section 10.15	Prior to EPU amendment implementation.
12. Quantitatively evaluate the impact of EPU changes on PRA results.	Enclosure 2 Section 10.16	Following PRA model update.
13. Conduct power ascension testing.	Enclosure 2 Section 13	Concurrent with power level increase.