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April 13, 2005
L-05-069

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

Subject: Beaver Valley Power Station, Unit No. 1
BV-1 Docket No. 50-334, License No. DPR-66
License Amendment Request 320

Pursuant to 10 CFR 50.90, FirstEnergy Nuclear Operating Company (FENOC) requests an amendment to the above license in the form of changes to the Beaver Valley Power Station (BVPS) Technical Specifications. This License Amendment Request (LAR) proposes Technical Specification changes that will support operation of BVPS Unit No. 1 with replacement steam generators at the current power level of 2689 MWt rated thermal power. This LAR does not request a power uprate for BVPS Unit No. 1.

An extended power uprate (EPU) license amendment request was submitted by FENOC letter L-04-125, dated October 4, 2004 (Reference 3). This submittal requested NRC approval by November 2005 in order to support operation of BVPS Unit No. 1 with the Model 54F replacement steam generators. The Model 54F steam generators are to be installed during the BVPS Unit No. 1 maintenance and refueling outage in the spring of 2006.

Schedule delays in FENOC providing the additional information specified in the NRC extended power uprate acceptance review letter of January 6, 2005 have been encountered such that NRC review and approval of the EPU LAR may not be completed in time to support the Unit No. 1 2006 spring outage. Due to these delays, an alternative approach has been defined to support implementation of the BVPS Unit No. 1 replacement steam generators during the 2006 spring outage. This alternative approach consists of submitting this BVPS Unit No. 1 replacement steam generator LAR separate from the EPU LAR. With this submittal, NRC review and approval of the EPU LAR can proceed on a schedule that is independent of the review of the steam generator replacement LAR.

The EPU LAR includes the Technical Specification and analysis methodology changes for operation of BVPS Unit No. 1 at 2900 MWt rated thermal power with the Model 54F steam generators. As such, the EPU analyses form the basis for operation of BVPS Unit

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No. 1 with the replacement steam generators at the current power level of 2689 MWt rated thermal power.

The safety and radiological analyses conducted to support this LAR assume an atmospheric containment design and adoption of the Westinghouse BELOCA analysis methodology, and are bounded by safety analyses performed at 2900 MWt rated thermal power. Therefore, implementation of the requested amendment is contingent upon implementation of the requested containment conversion (Reference 1) and BELOCA (Reference 2) amendments.

This submittal has the following enclosures.

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. This enclosure has four attachments. The proposed Technical Specification changes are provided in Attachment A. The proposed changes to the Technical Specification Bases are provided in Attachment B. The proposed changes to the Licensing Requirements Manual are provided in Attachment C. The regulatory commitments associated with this submittal are provided in Attachment D.

Enclosure 2, the Replacement Steam Generator Licensing Report, provides the technical justification for the proposed Technical Specification changes and analysis methodology changes.

Enclosure 3, the Replacement Steam Generator Component Report, contains a description of the Model 54F steam generators.

Enclosure 4, the Reviewer's Aid, contains two tables. Table 1 identifies what Technical Specification changes proposed in the previously submitted EPU LAR are, or are not, being proposed in this LAR and provides the reason. Table 2 identifies what portions of the previously submitted EPU Licensing Report are contained within the Replacement Steam Generator Licensing Report.

Approval of the proposed amendment is requested by January 2006 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 LAR require a plant outage to implement, the requested 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 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 hazards consideration as defined in 10 CFR 50.92 based on the safety analysis and no significant hazards evaluation contained in Enclosure 1.

The regulatory commitments made in this submittal are provided in Attachment D of Enclosure 1. If you have questions or require additional information, 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 April 13, 2005.

Sincerely,

L.W. Pearce

L. William Pearce

Enclosures:
1. FENOC Evaluation of the Proposed Changes
2. Replacement Steam Generator Licensing Report
3. Replacement Steam Generator Component Report
4. Reviewer's Aid

References:
1. FENOC Letter L-04-073, License Amendment Requests 317 and 190, dated June 2, 2004.
2. FENOC Letter L-04-124, License Amendment Requests 318 and 191, dated October 4, 2004.
3. FENOC Letter L-04-125, License Amendment Requests 302 and 173, dated October 4, 2004.

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 Request 320 (Unit No. 1)

Subject: Replacement Steam Generators for Beaver Valley Power Station Unit No. 1.

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A	Proposed Unit No. 1 Technical Specification Changes
B	Proposed Unit No. 1 Technical Specification Bases Changes
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D	Commitment List

1.0 DESCRIPTION

This is a request to amend Operating License DPR-66 (Beaver Valley Power Station Unit No. 1). The proposed changes will revise the Beaver Valley Power Station (BVPS) Unit No. 1 Technical Specifications to permit operating with replacement steam generators (Model 54F) installed.

This replacement steam generators license amendment request utilizes analyses performed at a bounding power level of 2900 MWt rated thermal power. The analyses were performed at the bounding power level with the intention of uprating BVPS Unit No. 1 at a later date. The bounding analyses were evaluated to demonstrate that they are applicable for the current power level of 2689 MWt rated thermal power with the Model 54F steam generators installed.

FirstEnergy Nuclear Operating Company (FENOC) submitted extended power uprate (EPU) license amendment request (LAR) 302 by letter L-04-125, dated October 4, 2004. This submittal requested NRC approval by November 2005 in order to support operation of BVPS Unit No. 1 with the Model 54F replacement steam generators (RSGs), which are to be installed during the BVPS Unit No. 1 2006 spring outage.

The EPU LAR included the Technical Specification and analysis methodology changes for operation of BVPS Unit No. 1 at 2900 MWt rated thermal power (RTP) with the Model 54F steam generators. As such, the EPU analyses form the licensing basis for operation of BVPS Unit No. 1 with RSGs. Schedule delays in FENOC providing the additional information specified in the NRC extended power uprate acceptance review letter dated January 6, 2005 have been encountered such that NRC review and approval of the EPU LAR may not be completed in time to support the Unit No. 1 2006 outage. Due to these delays, an alternative approach has been defined to support implementation of the BVPS Unit No. 1 RSGs during the 2006 spring outage. This alternative approach consists of submitting this BVPS Unit No. 1 RSG LAR separate from the EPU LAR but based on the EPU analyses.

This submittal contains only those Technical Specification and analysis methodology changes that require NRC review and approval to support operation of BVPS Unit No. 1 with the RSGs and at the current RTP. This RSG LAR does not request a power increase. This alternative approach reduces the number of Technical Specification changes requiring NRC review and approval to support operation with the RSGs and eliminates the need for review and approval of the Technical Specification change for an increase in RTP. With this submittal, NRC

review and approval of the EPU LAR can proceed on a schedule that is independent of the steam generator replacement outage.

This submittal has the following enclosures.

Enclosure 1, FENOC Evaluation of the Proposed Changes, includes a description of the changes, the technical analysis and the no significant hazards consideration.

Enclosure 2, the RSG Licensing Report, provides the technical justification for the proposed Technical Specification changes and analysis methodology changes.

Enclosure 3, the RSG Component Report, contains a description of the Model 54F steam generators.

Enclosure 4, the Reviewer's Aid, contains two tables that identify: 1) what Technical Specification changes proposed in the previously submitted EPU LAR are and are not being proposed in this RSG LAR and the reason, and 2) what portions of the previously submitted EPU Licensing Report are contained within the RSG Licensing Report.

The BVPS Unit No. 1 RSG Licensing Report (Enclosure 2) provides the technical justification for the Technical Specification and analysis methodology changes contained in this RSG LAR, including an expansion of the selective implementation of the Alternative Source Term (AST) methodology. The RSG Licensing Report contains the applicable portions of the EPU Licensing Report (i.e., sections, subsections, figures, and tables) that provide the technical justification for the Technical Specification and analysis methodology changes contained in this RSG LAR.

In order to facilitate NRC review of the information provided in this RSG submittal, as well as comparison to the information in the EPU submittal, Enclosure 1 (FENOC Evaluation of the Proposed Changes) and Enclosure 2 (RSG Licensing Report) of the RSG submittal use the same format and numbering convention as the EPU submittal. Those portions of the EPU Licensing Report that are included in the RSG Licensing Report are incorporated with minimal editing, such as removal of analyses and results applicable to BVPS Unit No. 2. Those portions of the EPU Licensing Report that are not included in the RSG Licensing Report are designated as "EPU Section" or "EPU Table." The designation "NA" (Not Applicable) has been used in tables to indicate that the information is not applicable to the RSG LAR. In this manner, the RSG Licensing Report retains the same format and numbering convention that was used in the EPU Licensing Report.

The RSG Licensing Report contains only those portions of the EPU Licensing Report that are required to support the RSG LAR Technical Specification and analysis methodology changes necessary for the RSG LAR. The provisions of 10 CFR 50.59 are being used to address analyses that are not dependent on Technical Specification or analysis methodology changes and, thus, do not require NRC review and approval for RSG implementation. Although the RSG Licensing Report includes general discussion of the Model 54F RSG component design features and structural integrity, the provisions of 10 CFR 50.59 are being used to address the RSGs as well as the impact of the RSGs on the analyses that are not dependent on Technical Specification and analysis methodology changes.

The proposed changes reflect revised safety and radiological analysis, as documented in Enclosure 2, "Beaver Valley Power Station Unit 1 Replacement Steam Generator Licensing Report", April 2005.

The Technical Specification (TS) changes requested include:

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

(b) modifying Overtemperature ΔT and Overpower ΔT equations;

(c) revising the steam generator water level low-low and high-high setpoints;

(d) revising the required steam generator secondary side level in Modes 4 and 5;

(e) revising the steam generator TS to reflect the replacement steam generators;

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

(g) adding WCAP-14565-P-A (VIPRE) and WCAP-15025-P-A (WRB-2M) to the list of NRC approved methodologies in TS 6.9.5.

Details on these proposed TS changes are provided in Section 2.3.

Two changes to the BVPS licensing basis that are not directly reflected in the TSs, but require NRC approval, are an expansion of the selective implementation of the Alternative Source Term (AST) methodology of Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors" (Reference 1) and use of the 1979 ANS Decay Heat + 2σ model (Reference 2) for mass and energy (M&E) releases for a main steamline break outside containment. These are discussed in Section 2.4.

To address the accident dose analyses impact of RSG, bounding analyses were performed at 2900 MWt utilizing the AST methodology. To address the M&E

releases for main steamline break outside containment a bounding analysis was performed at 2900 MWt utilizing the1979 ANS Decay Heat + 2σ model.

Some of the proposed TS and methodology changes also result in modifications to the TS Bases and Licensing Requirements Manual (LRM). The TS Bases and LRM changes are provided for completeness and information only. Where applicable, the necessary TS Bases and LRM changes are noted in Section 2.3.

2.0 PROPOSED CHANGES

The proposed TS changes, which are submitted for NRC review and approval, are provided in Attachment A. The changes proposed to the TS Bases are provided in Attachment B. The changes proposed to the LRM are provided in Attachment C. Attachment D provides a list of commitments associated with this submittal.

The proposed TS 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 TS Bases changes in accordance with 10 CFR 50.59. The BVPS Licensing Document Control Program controls the review, approval and implementation of LRM changes. The TS Bases and LRM changes are provided for information only.

The proposed changes to the TSs, 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, TSs, 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 other pending LARs. Approval of the pending LARs is expected prior to, or concurrent with, the approval of this request. The cover pages of Attachments A, B and C list the pages affected by the pending LARs, as applicable. The applicable LAR number identifies the page of a pending LAR that is being revised by this request. The applicable pending LARs for Unit No. 1 are 310, 317, 318 and 327, which are described as follows.

- Pending LAR 310 was submitted by FENOC letter L-05-009, dated February 11, 2005 (Reference 3). 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 TS 6.9.5.
- Pending LAR 317 was submitted by FENOC letter L-04-073, dated June 2, 2004 (Reference 4). This LAR proposes the necessary changes to reflect conversion of the current BVPS sub-atmospheric containment to an atmospheric design. The pertinent changes made by this LAR appear in the TSs and the LRM.
- Pending LAR 318 was submitted by FENOC letter L-04-124, dated October 4, 2004 (Reference 5). 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 (Reference 6). The pertinent changes made by this LAR appear in Specification 6.9.5.
- Pending LAR 327 was submitted by FENOC letter L-04-127, dated October 5, 2004 (Reference 7) and supplemented by letter L-05-046, dated March 22, 2005 (Reference 8). This LAR modifies steam generator level allowable value setpoints used in the reactor trip system and engineered safety feature actuation system instrumentation for the current steam generators to address identified non-conservative setpoints. The pertinent changes made by this LAR appear in TSs and the LRM. The responses provided in letter L-05-046 also apply to this RSG LAR. Specifically, FENOC Letter L-05-046 response addresses the industry issue associated with acceptable methodology to calculate Allowable Values (AV). This response is applicable for the methodology used to calculate Overtemperature ΔT, Overpower ΔT, Steam Generator Level Low-Low, and Steam Generator Level High-High Allowable Values discussed in this LAR.

2.2 Supporting LARs

Of the four pending LARs listed in Section 2.1, only LAR 317 (Containment Conversion) and LAR 318 (Best Estimate Loss of Coolant Accident) are required to be implemented prior to or concurrent with this LAR since they form a portion of the necessary supporting analyses.

2.3 Proposed TS Changes

The following table identifies, by LAR applicability and highlighting, which of the TS changes proposed in the EPU LAR are being proposed in the RSG LAR.

Affected Technical Specifications			
No.	**Unit No. 1**	**Applicable LAR**	**Title**
1	License page 3	EPU	Item 2.C(1) Maximum Power Level
2	License page 3	EPU	Item 2.C(2) Technical Specifications
3	1.0	EPU	DEFINITIONS – 1.3 RATED THERMAL POWER
4	2.1.1	RSG	SAFETY LIMITS – REACTOR CORE
5	3.1.2.8	EPU	REFUELING WATER STORAGE TANK (RWST)
6	3.3.1.1	EPU	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	RSG	REACTOR TRIP SYSTEM INSTRUMENTATION (Table 3.3-1, FUNCTIONAL UNIT 14, Steam Generator Water Level Low-Low)
8	3.3.1.1	RSG	REACTOR TRIP SYSTEM INSTRUMENTATION (Table Notation, Overtemperature/Overpower ΔT)
9	3.3.1.1	EPU	REACTOR TRIP SYSTEM INSTRUMENTATION (Table Notation, Action 8)
10	3.3.2.1	EPU	ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION (Table 3.3-3, Footnote to Steamline Pressure – Low)
11	3.3.2.1	RSG	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)
12	3.4.1.3	RSG	REACTOR COOLANT SYSTEM – SHUTDOWN (SR 4.4.1.3.3)
13	3.4.3	EPU	REACTOR COOLANT SYSTEM – SAFETY VALVES
14	3.4.5	RSG	STEAM GENERATORS
15	3.4.8	EPU	REACTOR COOLANT SYSTEM – SPECIFIC ACTIVITY
16	3.5.1	EPU	ACCUMULATORS
17	3.5.4.1.1	EPU	BORON INJECTION TANK ≥ 350°F
18	3.5.4.1.2 3.5.2 3.5.3	EPU EPU EPU	BORON INJECTION TANK < 350°F ECCS SUBSYSTEMS - T_{avg} ≥ 350°F ECCS SUBSYSTEMS - T_{avg} < 350°F
19	3.5.5	RSG	SEAL INJECTION FLOW
20	3.7.1.1	EPU	TURBINE CYCLE – MAIN STEAM SAFETY VALVES (MSSVs)
21	3.7.1.3	EPU	PRIMARY PLANT DEMINERALIZED WATER (PPDW)
22	3.7.1.4	EPU	PLANT SYSTEMS - ACTIVITY
23	6.9.5	RSG	CORE OPERATING LIMITS REPORT (COLR)

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

Change Number 1 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 2 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 3 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 4

This proposed change is a modification to TS 2.1.1.1, "SAFETY LIMITS – REACTOR CORE." The modification consists of specifying the departure from nucleate boiling ratio (DNBR) for two different departure from nucleate boiling (DNB) correlations. For Vantage 5H (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.

Although not a matter for NRC approval, the TS Bases is further modified by adding a reference to the Revised Thermal Design Procedure (RTDP) approved by BVPS Unit No. 1 License Amendment No. 239 (Reference 9) 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 in the TS Bases. 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 TS 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 10) to the list of approved methodologies used to determine core operating limits.

Basis for Change Number 4

This LAR is requesting NRC approval to use the NRC previously approved WRB-2M correlation for predicting critical heat flux at BVPS. This change is being made to support enhanced fuel performance. Presently TS 2.1.1.1 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. The Unit 1 core may contain solely RFA fuel assemblies, or a mixture of RFA fuel assemblies and previously burned V5H fuel assemblies. With the proposed change, TS 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 the standard thermal design procedure (STDP), the revised thermal design procedure (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-P-A to TS 6.9.5 is necessitated by the inclusion of the WRB-2M correlation in TS 2.1.1.1.

Change Number 5 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 6 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 7

This proposed change is a modification to TS 3.3.1.1, "REACTOR TRIP SYSTEM INSTRUMENTATION." 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 RSGs. 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 No. 1 Model 54F RSGs incorporate a narrow range span of 212 inches, which is larger than the Unit No. 1 Model 51 original steam

generators (OSG) narrow range span of 144 inches. This design difference necessitated that the low-low water level setpoint and allowable value be revised.

The setpoint analysis uses the Square-Root-Sum-of-the-Squares (SRSS) technique to combine the uncertainty components of an instrument channel in an appropriate combination of those components, or groups of components, which are statistically independent. Those uncertainties that are not independent are arithmetically summed to produce groups that are independent of each other, which can then be statistically combined. The methodology used for these proposed setpoint changes is defined in WCAP-11419-P-A, Rev. 4, "Westinghouse Setpoint Methodology for Protection Systems – Beaver Valley Power Station Unit 1," March 2004 (Reference 11). The same methodology described in References 7 and 8 was used to determine the steam generator level setpoints in this LAR.

Incorporating the proposed TS and Core Operating Limits Report (COLR) changes will support operation with the RSGs in a manner consistent with the Updated Final Safety Analysis Report (UFSAR) assumptions. All of the new proposed reactor trip system steam generator level functions have acceptable margins and therefore are acceptable for the EPU power level of 2900 MWt. The results and conclusions of the analyses and evaluations performed for these proposed reactor trip system setpoints for the EPU power level bound and support operation at the current reactor power level of 2689 MWt.

Change Number 8

This proposed change modifies TS 3.3.1.1, "REACTOR TRIP SYSTEM INSTRUMENTATION." 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 TS Bases is modified by deleting the statement that the Overpower ΔT trip is not credited. The trip is credited in the analyses, which support this LAR. The LRM is also modified as necessary to reflect this change.

The existing Unit 1 No. 1 Overtemperature ΔT and Overpower ΔT equations shown on Unit No. 1 TS pages 3/4 3-5 and 3/4 3-5a have two deviations from NUREG-1431, Revision 3, "Standard Technical Specifications Westinghouse Plants," June 2004 (Reference 12). The existing Unit No. 1 Overtemperature ΔT and Overpower ΔT equations do not include lag compensators (annotated as τ_3 and τ_6 in Reference 12). Additionally, the existing Unit No. 1 Overtemperature ΔT and Overpower ΔT equations do not include a lead/lag compensator (annotated as τ_1 and τ_2 in Reference 12).

The proposed Unit No. 1 Overtemperature ΔT and Overpower ΔT equations have been revised to include the addition of lag compensators (annotated as τ_3 and τ_6 in the Reference 12). The proposed lag compensators for the Overtemperature ΔT and Overpower ΔT equations are annotated as τ_4 and τ_5 in the Unit No. 1 TS. The addition of lag compensators will modify the existing Unit No. 1 Overtemperature ΔT and Overpower ΔT equations such that lag compensation is consistent with the mathematical form shown in the Reference 12. The lag compensators were added to increase operating margin by reducing signal noise impact to the trip functions.

The remaining mathematical difference between Unit No. 1 Overtemperature ΔT and Overpower ΔT equations and the Westinghouse Standard Technical Specifications equations is the lead/lag transfer function (annotated as τ_1 and τ_2 in the Reference 12). The hardware to provide this specific lead/lag compensation function has never been installed at Unit No. 1. Therefore it would be inconsistent to show time constants in the TS that do not physically exist in the plant. The existing Unit No. 1 safety analysis did not require the use of the lead/lag compensator function. The proposed Overtemperature ΔT and Overpower ΔT parameters were established to optimize operator margin within the constraints of the safety analysis.

Basis for Change Number 8

Section 5.3 of Enclosure 2 provides the technical justification for the proposed change to the generated functions identified above. The changes are being proposed to optimize operating margins. The evaluation documented in Enclosure 2 demonstrates that the plant operating margins are adequate.

To address the non loss of coolant analyses impact of RSGs, bounding analyses were performed at 2900 MWt utilizing the revised Overtemperature ΔT and Overpower ΔT setpoints and time constants.

As stated in Section 5.3.19 of Enclosure 2, the Overpower ΔT trip is credited in the EPU steamline break analyses. For BVPS Unit No. 1, the 0.6 square feet break size is the most limiting break size with respect to peak heat flux and minimum DNBR for the full power steamline rupture – core response event. The DNB design basis is met. Therefore, this event does not adversely affect the core or reactor coolant system (RCS), and all applicable criteria are met. The results and conclusions of the analysis performed for the steam system piping failure at a power level of 2900 MWt bound and support operation at the current power level of 2689 MWt.

Bounding initial conditions for DNB parameters (T_{avg}, Pressurizer Pressure, and RCS total flow) have been revised based on safety analysis input assumptions. The values include control and indication uncertainties. In addition the response time acceptance criteria for the pressurizer pressure and neutron flux input assumed in the safety analysis for the Overtemperature ΔT function is specified in a Note applicable to LRM Table 3.1-1a.

Change Number 9 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 10 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 11

This proposed change is a modification to TS 3.3.2.1, "ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION." 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 RSGs. This proposed change is reflected in the LRM. There is no corresponding change to the TS Bases for this change.

An additional change is made to the entry in the "CHANNELS TO TRIP" column for Functional Units 5.a, where the entry is changed to read "2/loop" instead of " 2 loop". This change is being made to correct a format error than occurred when License Amendment 239 was issued.

Basis for Change Number 11

Section 5.10 of Enclosure 2 provides the technical justification for proposed setpoint changes. The Unit No. 1 RSG incorporates a narrow range span of 212 inches, which is larger than the Unit No. 1 OSG narrow range span of 144 inches. The Model 54F design necessitates that the low-low and high-high water level setpoints and allowable values are revised.

The setpoint analysis uses the Square-Root-Sum-of-the-Squares (SRSS) technique to combine the uncertainty components of an instrument channel in an appropriate combination of those components, or groups of components, which are statistically independent. Those uncertainties that are not independent are arithmetically summed to produce groups that are independent of each other, which can then be statistically combined. The methodology used for these proposed setpoint changes

is defined in WCAP-11419-P-A, Rev. 4, "Westinghouse Setpoint Methodology for Protection Systems – Beaver Valley Power Station Unit 1," March 2004 (Reference 11). The same methodology described in References 7 and 8 was used to determine the steam generator level setpoints in this LAR.

Incorporating the proposed TS and COLR changes will support operation with the RSGs in a manner consistent with the UFSAR assumptions. All of the new proposed engineered safeguards features actuation system (ESFAS) steam generator level functions have acceptable margins and therefore are acceptable for the operation at EPU conditions. The results and conclusions of the analyses and evaluations performed for these ESFAS setpoints for the reactor power of 2900 MWt bound and support operation at the current reactor power of 2689 MWt.

Change Number 12

This proposed change is a modification to TS 3.4.1.3, "REACTOR COOLANT SYSTEM – SHUTDOWN." . 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. The wording of Surveillance Requirement 4.4.1.3.3 is also revised by replacing " ... equivalent ... " with " ... greater than or equal ... " for consistency between the two units and the Standard Technical Specifications (Reference 12). There are no corresponding changes to the TS Bases or LRM for these changes.

Basis for Change Number 12

Enclosure 3 and Section 4.7.1 of Enclosure 2 provide the technical justification for the proposed change in Surveillance Requirement 4.4.1.3.3. The Unit No. 1 RSG incorporates a narrow range span of 212 inches, which is larger than the Unit No. 1 OSG narrow range span of 144 inches. In order to obtain the larger span, the narrow range span lower level tap is located in the transition cone below the top of the tube bundle. This design difference necessitated that the TS level used to verify operability of the reactor coolant loops be revised.

Change Number 13 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 14

The current steam generator TS format is being retained until the industry action regarding Technical Specification Task Force (TSTF) 449, "Steam Generator Tube Integrity", Revision 3, is finalized. A revised steam generator LAR will be

submitted to the NRC within 6 months following the notice of availability for adoption of TSTF-449 under the consolidated line item improvement process.

These proposed changes are modifications to TS 3.4.5, "STEAM GENERATORS." The proposed changes to TS 3.4.5 consist of removing references to steam generator sleeving and alternate tube repair criteria (voltage based repair, steam generator tube-to-tube support plate), which are not applicable for the replacement steam generators.

Additional administrative changes involving format and renumbering are necessary to address criteria that are being deleted.

Changes were made in 4.4.5.2.3, 4.4.5.3.b and the C-3 result column of Table 4.4-2 for clarification of existing criteria. These changes do not alter the current requirements.

The inspection frequency listed in 4.4.5.3.a was revised to address the first inservice inspection for the new RSG Model 54F steam generators after startup, consistent with the prior criteria for the first startup of the current steam generators. In addition, a note was added to indicate that the TS specified steam generator inservice inspection is not required during the steam generator replacement outage since the inspections performed as part of the steam generator manufacturing process and installation are sufficient to identify any pre-operation defects.

The all volatile treatment criteria in 4.4.5.3.a is deleted because this treatment has been in use at Unit No. 1 for several years and is now normal practice which will carry forth for the RSGs, eliminating the need to specifically identify this past clarification. The proposed change is reflected in the TS Bases. There is no corresponding change to the LRM for this change.

Basis for Change Number 14

Enclosure 3 and Section 4.7.1 of Enclosure 2 provide a discussion of the BVPS Unit No. 1 RSGs. 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. BVPS Unit 1 has a steam generator program which is consistent with the EPRI Technical Report No. 1003138, Revision 6, "PWR SG Examination Guidelines," October 2002 (Reference 13) and NEI 97-06, Revision 1, "Steam Generator Program Guidelines," January 2001 (Reference 14).

Change Number 15 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 16 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 17 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 18 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 19

This proposed change consists of a modification to TS 3.5.5, "EMERGENCY CORE COOLING SYSTEMS - SEAL INJECTION FLOW." The modification consists of two changes. The first change increases the minimum value of the charging pump discharge pressure for reactor coolant pump (RCP) seal injection flow. This proposed change is reflected in the TS Bases. There is no corresponding change to the LRM for this change.

The second change increases the reactor coolant system pressure values in the Note for TS Surveillance Requirement 4.5.5 by 5 psig to be consistent with current normal operating pressure of 2235 psig.

Basis for Change Number 19

The purpose of the change is to reflect the analytical resistance used for the seal injection flow path in the calculation of safety injection flow for the EPU conditions. The normal power operation surveillance requirements for the

charging pump discharge pressure surveillance requirement was increased from 2,397 psig to 2,457 psig for BVPS Unit No. 1 to support the revised safety analysis used in this LAR. Details of the analysis justifying this change are not provided in Enclosure 2. The following provides the necessary technical justification.

To address the small break loss of coolant accident impact of RSGs, a bounding analysis was performed at 2900 MWt utilizing the revised safety injection flows.

The surveillance allows a total seal injection flow of 28 gpm to all three RCPs. The discharge pressure acceptance criterion is the pressure indicated at the discharge of the charging pump during the surveillance. The discharge pressure acceptance criterion is based on a more detailed Westinghouse methodology that includes RCP balancing chamber conditions.

The TS and corresponding Surveillance Requirement are based on a maximum flow rate because the surveillance is actually verifying that a minimum friction loss coefficient (consistent with the analytical value modeled in the safety injection system flow analyses) exists for the seal injection lines. Restricting the seal injection resistance to a minimum value assures that a limited amount of seal injection flow is diverted to the seals during safety injection actuation. Seal injection flow reaching the reactor is not credited in LOCA events and RCP thermal barrier cooling from the component cooling water system performs a redundant seal cooling function to seal injection.

The increased minimum discharge pressure functions to limit the flow to the RCP seals when the charging pumps are operating as high head safety injection pumps, thereby improving high head safety injection flowrate for a postulated small break LOCA. See Section 5.2.2 of Enclosure 2 for a discussion of the small break LOCA analysis with the Model 54F steam generators.

Surveillance Requirement 4.5.5 is not required to be performed until 4 hours after the RCS pressure has stabilized within a ±20 psig range of normal operating pressure. The RCS pressure requirement is specified since this configuration will produce the required pressure conditions necessary to assure that the manual valves are set correctly. The current normal operating pressure is 2235 psig. Thus, the range of pressure for this note should be 2215 psig to 2255 psig.

Surveillance procedures specify that an RCP can operate within a seal injection flow range of 6 to 13 gpm, with a nominal flow of 8 gpm per RCP. Control room annunciation is also provided to alert of a low seal injection flow condition. Therefore, some allowable variation in the operating seal injection flow is acceptable while remaining within the surveillance limit.

Change Number 20 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 21 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

Change Number 22 (EPU Change)

This change number is included to maintain numbering consistency with the EPU LAR. The information in this change is not applicable for the RSG LAR.

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 15) and WCAP-15025-P-A (Reference 10) to the list of NRC approved methodologies in TS 6.9.5, "CORE OPERATING LIMITS REPORT (COLR)". There is no corresponding change to the TS Bases or LRM for the addition of the WCAPs to TS 6.9.5.b.

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.

The addition of WCAP-15025-P-A to TS 6.9.5.b provides the justification for the use of the WRB-2M correlation for the RFA fuel as described in Change Number 4.

Other TS Bases and LRM Changes

Section 2.3 identifies when a proposed TS change results in a change to the TS Bases or LRM. However the TS Bases and LRM also contain changes that are not the result of the proposed changes to the TS. One of the areas that require changes to the TS Bases and LRM is the expansion of the selective implementation of the

AST methodology. The expansion of the AST methodology is reflected in both the TS Bases and LRM. Another area is where the TS Bases is changed to reflect the safety analyses without a corresponding TS change. This type of TS Bases change appears in TS Bases 3/4.3.1 and 3/4.3.2, "REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION", where main steamline break is added as a protective function under the section heading "Safety Injection Input from ESF." The other TS Bases changes that reflects the safety analyses is revising the TS Bases for TS 3.7.1.2, Auxiliary Feedwater System, to reflect the number of auxiliary feedwater pumps assumed in the analysis. It is noted that this analysis assumption does not require a change to the pump operability requirements specified in TS 3.7.1.2.

These TS Bases and LRM changes are provided for completeness and information only and are not discussed further.

2.4 Proposed Methodology Changes

Two changes to the BVPS licensing basis that are not directly reflected in the Technical Specifications, but require NRC approval, are an expansion of the selective implementation of the AST methodology of Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors" (Reference 1) and use of the 1979 ANS Decay Heat + 2σ model (Reference 2) for mass and energy (M&E) releases for a main steamline break outside containment.

To address the accident dose analyses impact of RSG, bounding analyses were performed at 2900 MWt utilizing the AST methodology. To address the M&E releases for main steamline break outside containment a bounding analysis was performed at 2900 MWt utilizing the1979 ANS Decay Heat + 2σ model.

The expansion of the selective implementation AST, as defined in Section 1.2.2 of Reference 1 includes all accidents impacted by the RSGs. Section 5.11 of Enclosure 2 discusses the impact of RSGs on the site boundary and control room doses for the applicable accidents listed below.

(a) Control Rod Ejection Accident (CREA)

(b) Main Steam Line Break (MSLB) outside containment

(c) Steam Generator Tube Rupture (SGTR)

(d) Locked Rotor Accident (LRA)

(e) Loss of AC Power (LACP)

(f) Small Line Break (SLB) outside containment

It is noted that the CREA is addressed in this application by reference only, since the accident analyses were performed assuming RSGs and EPU conditions and was approved by License Amendment No. 257. The Loss of Coolant Accident (LOCA) and the Fuel Handling Accident (FHA) are not impacted by the RSGs and have been approved for BVPS Unit No. 1 by License Amendments 257 and 241, respectively (References 16 and 17, respectively).

Core decay heat generation assumed in calculating the steamline break M&E releases is based on the 1979 ANS Decay Heat + 2σ model (Reference 2). The existing analyses assumed the use of the 1971 standard (+20% uncertainty) for the decay heat. The use of the 1979 version represents a deviation from the current licensing basis MSLB M&E releases outside containment analysis for BVPS Unit No. 1.

The 1979 decay heat model has been previously used by Westinghouse in other analyses for BVPS Unit 1, which are pending NRC approval. The analyses are LOCA and MSLB inside containment. Use of the model for LOCA M&E releases has been approved by the NRC (Reference 18) and is contained in the Containment Conversion LAR submittal (LAR 317 - Reference 4) which requests NRC approval. Use of the model for MSLB inside containment M&E releases has also been submitted for NRC review and approval in the Containment Conversion LAR (See Sections 2.1 and 2.2 of this enclosure). Use of the model for MSLB outside containment M&E releases at BVPS Unit 1 is being submitted for NRC review and approval in this RSG LAR. Use of the 1979 model has been approved by the NRC for similar applications on other plants.

3.0 BACKGROUND

The following provides a background discussion of the 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 (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

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 LAR, 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.

3.3 Refueling Water Storage Tank (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

3.4 Power Range, Neutron Flux High Negative Rate Trip (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

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 TSs. The setpoint for the trip is continuously calculated by analog circuitry for each loop by solving the equation found in the table notation section of TS Table 3.3-1.

The Overpower ΔT trip protects against excessive power and trips the reactor on coincidence. The setpoint for each channel is continuously calculated by analog circuitry for each loop by solving the equation found in the table notation section of TS 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) and deviation from nominal RCS pressure are also factors 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 (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

3.7 Accumulators (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

3.8 Boron Injection Tank (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

3.9 Main Steam Safety Valves (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

3.10 Primary Plant Demineralized Water Storage Tank (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

3.11 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. 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.

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.

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 – Modes 4 and 5

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 No. 1 replacement steam generators are Model 54F 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.

Section 4.7.1 of Enclosure 2 provides a brief description of the Unit No. 1 replacement 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. A more detailed description of the Model 54F steam generator is provided in Enclosure 3.

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 (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

3.15 Secondary Coolant System Specific Activity (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

3.16 Welded Steam Generator Sleeves (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

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. 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-P-A (Reference 15) 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.

3.18 WRB-2M Correlation

Nuclear fuel correlations are used to predict the initiation of boiling crisis at the surface of the fuel rods, which might lead to fuel damage. Boiling crisis occurs when the heat flow rate at the cladding surface exceeds a critical heat flux (CHF) so that the mode of heat transfer changes from nucleate boiling to film boiling.

The Vantage 5 fuel design incorporates intermediate flow mixer (IFM) grids. The IFM mixing vanes were the same as the mixing vanes in the standard support grids except the IFM grids had no structural function. Additional CHF tests were performed by Westinghouse for this design and a new CHF correlation was developed called WRB-2. The WRB-2 correlation is similar to the WRB-1 correlation but includes a term that accounts for the change in CHF performance as grid spacing changes. Westinghouse has further modified the fuel design to reduce fuel rod mechanical wear and to further improve thermal/hydraulic performance. In the modified fuel design, the mixing vanes are slightly longer than the previous design. Critical heat flux tests of the modified fuel were conducted with and without control rod guide thimbles, and with and without modified intermediate flow mixer grids. Although the data from these tests could be successfully correlated using WRB-2, a better correlation was obtained when a multiplier "M" was developed using statistical regression techniques. The improved correlation is called WRB-2M. The WRB-2M correlation would be applicable to the Westinghouse RFA and RFA-2 fuel products.

4.0 TECHNICAL ANALYSIS

The technical analysis conducted to support the proposed TS changes identified as RSG and AST related are documented in Enclosure 2. Enclosure 2 includes the evaluation of initial condition uncertainties at EPU conditions for the RSGs, 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 TS Bases and the LRM that are a result of the proposed changes.

A brief description of the technical analysis for the proposed TS changes is provided in the following paragraphs.

4.1 Affected Technical Specification Systems, Components and Parameters

4.1.1 Rated Thermal Power (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

4.1.2 Fuel Assemblies

The supporting studies, documented in Section 6 of Enclosure 2, concluded that the V5H and RFA fuel assemblies are structurally and mechanically acceptable for the bounding EPU conditions and the RSGs.

4.1.3 Refueling Water Storage Tank (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

4.1.4 Power Range, Neutron Flux High Negative Rate Trip (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

4.1.5 Overtemperature ΔT and Overpower ΔT

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

4.1.6 Pressurizer Safety Valves (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

4.1.7 Accumulators (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

4.1.8 Boron Injection Tank (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

4.1.9 Main Steam Safety Valves (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

4.1.10 Primary Plant Demineralized Water Storage Tank (EPU Section)

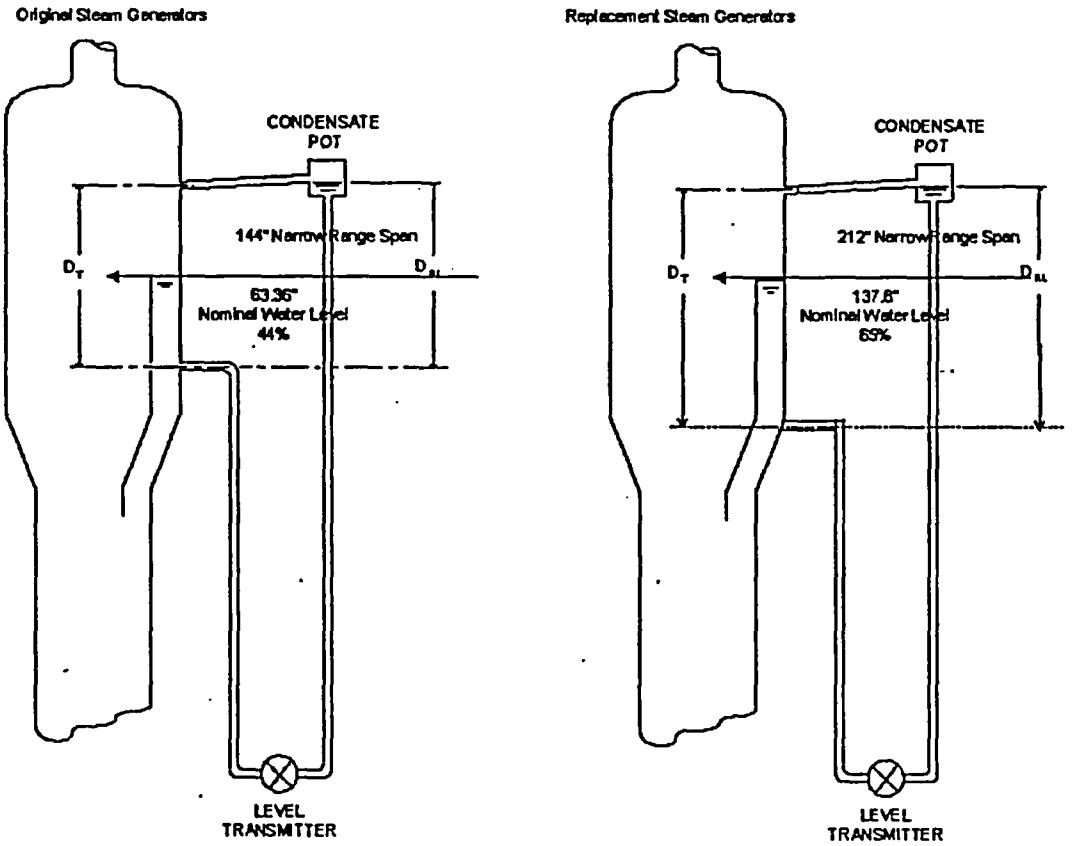
This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

4.1.11 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 No. 1 RSGs, which incorporate a larger narrow range span than the Unit No. 1 OSGs. The revised setpoint and allowable value were calculated for EPU conditions and incorporate the recommendations provided in Westinghouse NSAL-03-9 (Reference 19).

The existing Barton narrow range transmitters are being replaced with qualified Barton transmitters that address the increased narrow range instrument span. Wide range transmitter span is not being changed; therefore, the existing instrumentation will be re-used. The following sketch shows a general view of the new RSG level instrumentation.



As discussed in Section 5 of Enclosure 2, applicable safety analyses were performed incorporating the Unit No. 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 No. 1 RSG. The analyses in Enclosure 2 demonstrate that the implementation of the Unit No. 1 RSGs, and the incorporation of the associated low-low water level setpoint and allowable value, support operation of BVPS Unit No. 1 at the EPU conditions. These analyses performed for the EPU conditions bound and support operation at the current licensed 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 No. 1 RSGs, which

incorporate a larger narrow range span and a different nominal indicated water level than the Unit No. 1 OSGs. The revised setpoint and allowable value were calculated for the EPU conditions and incorporate the recommendations provided in Westinghouse NSAL-03-9 (Reference 19).

As discussed in Section 5 of Enclosure 2, applicable safety analyses were performed incorporating the Unit No. 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 No. 1 RSG. The analyses in Enclosure 2 demonstrate that the implementation of the Unit No. 1 RSGs and the incorporation of the associated high-high water level setpoint and allowable value support operation of BVPS Unit No. 1 at the EPU conditions. These analyses performed for the EPU conditions bound and support operation at the current licensed 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 No. 1 RSGs, which incorporate a larger narrow range span than the Unit No. 1 OSGs. The revised value was calculated for the Unit No. 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. The confirmation of natural circulation capability for the EPU conditions bound and support operation at the current licensed power level of 2689 MWt.

4.1.12 Steam Generators

Enclosure 3, and Section 4.7.1 of Enclosure 2, provide descriptions of the Unit No. 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 No. 1 RSGs have been designed and analyzed for operation at the EPU conditions, which bound and support operation at the current licensed 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 20) to justify the TS tube plugging limit of 40% wall thickness.

This steam generator model has been in service at the Farley Nuclear Plant since the spring of 2000.

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 reflect the analytical resistance used for the seal injection flow path. 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 (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

4.1.15 Secondary Coolant System Specific Activity (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

4.1.16 Welded Steam Generator Sleeves (EPU Section)

This section number is included to maintain numbering consistency with the EPU LAR. The information in this section is not applicable for the RSG LAR.

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 of Enclosure 2),
- startup of an inactive reactor coolant pump (Section 5.3.1 of Enclosure 2), and

- a feedwater malfunction (Section 5.3.9 of 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, engineering hot channel factors for enthalpy rise and heat flux are specific to the reactor core being analyzed. These BVPS specific inputs are noted throughout 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 is also used when using VIPRE.

The NRC Safety Evaluation Report dated January 19, 1999 (Reference 21) states that a utility's use of VIPRE, as described in WCAP-14565-P-A (Reference 15) 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 specified four conditions are met. 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. Sections 5.3 and 6.1 of Enclosure 2 provide the appropriate CHF correlation, DNBR limit, engineering 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. Sections 5.3 and 6.1 of Enclosure 2 provide 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, power shape and nuclear peaking factors used in the BVPS EPU analysis.

Condition 3. "The NRC staff's generic SER for VIPRE set requirements for use of new CHF correlations with VIPRE. Westinghouse has met these requirements for using the WRB-1, WRB-2, and WRB-2M correlations. The DNBR limit for WRB-1 and WRB-2 is 1.17. The WRB-2M correlation has a DNBR limit of 1.14. 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. In addition, the W-3 correlation can be used with VIPRE as described in the Westinghouse response to the NRC Supplemental Request for Additional Information regarding WCAP-14565, Rev. 0.

Condition 4. "Westinghouse proposes to use the VIPRE code to evaluate fuel performance following postulated design-basis accidents, including beyond-CHF heat transfer conditions. These evaluations are necessary to evaluate the extent of core damage and to ensure that the core maintains a coolable geometry in the evaluation of certain accident scenarios. 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. Westinghouse proposes to use conservative input in order to account for these effects. 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 does not use VIPRE for such conditions.

4.1.18 WRB-2M Correlation

The NRC Safety Evaluation Report dated December 1, 1998 (Reference 22) states that a utility's use of WRB-2M correlation with a DNBR limit of 1.14 for plant safety analyses, as described in WCAP-15025-P-A (Reference 10) may be approved by the NRC staff, and may be used provided the specified four conditions are met. Each of the four conditions, and their fulfillment, is addressed below.

Condition 1. "Since WRB-2M was developed from test assemblies designed to simulate Modified 17x17 Vantage 5H fuel, the correlation may only be used to perform evaluation for fuel of that type without further justification. Modified Vantage 5H fuel with or without modified intermediate flow mixer grids may be evaluated with WRB-2M."

This condition is met. The structural mid-grid design used in the RFA fuel assembly is a minor modification of the Modified Low Pressure Drop mid-grid that was addressed in WCAP-15025-P-A for use with the WRB-2M DNB correlation. The RFA mid-grid design was evaluated by means of the NRC-approved Fuel Criteria Evaluation Process (FCEP) (Reference 23). By complying with the requirements of FCEP, it has been demonstrated that the new mid-grid design meets all design criteria of existing tested mid-grids that form the basis of the WRB-2M correlation database and that the WRB-2M correlation with a 95/95 correlation limit of 1.14 applies to the new RFA mid-grid. As required by FCEP, the Westinghouse notification to the NRC of the RFA mid-grid design modifications and the validation of the WRB-2M DNB correlation applicability to the RFA mid-grid was provided in written notification to the NRC (Reference 24).

Condition 2. "Since WRB-2M is dependent on calculated local fluid properties, these should be calculated by a computer code that has been reviewed and approved by the NRC staff for that purpose. Currently WRB-2M with a DNBR limit of 1.14 may be used with the THINC-IV computer code. The use of VIPRE-01 by Westinghouse with WRB-2M is currently under separate review."

This condition is met. For the RFA fuel in BVPS Unit 1, the analysis of the RFA fuel was based on the VIPRE computer code (as licensed by Westinghouse in Reference 15) and the WRB-2M DNB correlation with a 95/95 correlation limit of 1.14. The use of VIPRE by Westinghouse with WRB-2M was approved by the NRC as part of Reference 21. As discussed for Condition 1, the Westinghouse notification to the NRC of the validation of the WRB-2M DNB correlation applicability to the RFA mid-grid was provided in Reference 24.

Condition 3. "WRB-2M may be used for PWR plant analyses of steady state and reactor transients other than loss of coolant accidents. Use of WRB-2M for loss of coolant accident analysis will require additional justification that the applicable NRC regulations are met and the computer code used to calculate local fuel element thermal/hydraulic properties has been approved for that purpose."

This condition is met. The WRB-2M correlation is not used for the loss of coolant accident analysis of the RFA fuel in BVPS Unit 1.

Condition 4. "The correlation should not be used outside its range of applicability defined by the range of the test data from which it was developed. The range is listed in Table 1."

This condition is met. Application of the WRB-2M correlation to the RFA fuel upgrade in BVPS Unit 1 was consistent with the range of parameters specified in Table 4-1 of WCAP-15025-P-A.

4.2 Radiological Analyses

Section 5.11 of Enclosure 2 documents the radiological analyses conducted to support the RSGs. The revised radiological analyses utilize an expansion of the selective 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, Reference 17) and the loss-of-coolant and control rod ejection accidents (Amendment 257, Reference 16).

The evaluation of the post accident radiological consequences demonstrate that offsite and control room doses associated with accidents will be within the acceptance criteria of 10 CFR 100 or 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 TSs allowing operation of BVPS Unit No. 1 with the RSGs 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 BVPS Unit No. 1 with the RSGs.

4.3 Related Plant Modifications

The principal modifications planned to support implementation of the RSG LAR analyses include:

1. Containment Conversion from a sub-atmospheric to an atmospheric design basis including related modifications such as the addition of feedwater isolation valves (FIVs) and auxiliary feedwater flow limiting venturies for BVPS-1 (LAR 317 - Reference 4).

2. Replacement steam generators and narrow range level transmitters installed.

3. Replacement charging/safety injection pump rotating assemblies installed with rebalancing the injection flows and extending the pump runout limit.

4. Replace or modify the Unit 1 Overtemperature ΔT and Overpower ΔT instrumentation to incorporate lead/lag filters that accommodate the assumed time constants.

5. Make RSG LAR instrumentation setpoint changes (includes revised reactor trip system and engineered safety features actuation system setpoints).

6. Feedwater control valve trim changes. Note: the feedwater control valve trim is scheduled for replacement during steam generator replacement refueling outage and the RSG LAR analysis supports the new trim size. However, the installation of the new trim is not required in order to maintain the RSG LAR safety analysis valid and hence, is not a required action in order to implement the RSG LAR.

5.0 REGULATORY SAFETY ANALYSIS

The Beaver Valley Power Station (BVPS) Technical Specification (TS) changes requested include:

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

(b) modifying Overtemperature ΔT and Overpower ΔT equations;

(c) revising the steam generator water level low-low and high-high setpoints;

(d) revising the required steam generator secondary side level in Modes 4 and 5;

(e) revising the steam generator TS to reflect the replacement steam generators;

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

(g) adding WCAP-14565-P-A (VIPRE) and WCAP-15025-P-A (WRB-2M) to the list of NRC approved methodologies in TS 6.9.5.

Although this License Amendment Request (LAR) does not request an increase in the licensed maximum power level, the safety analyses used to support this LAR were based on a proposed increase in the licensed maximum power level previously requested in an extended power uprate (EPU) LAR. These safety analyses are conservative and bounding for operation of the replacement steam generators (RSG) at the current licensed maximum power level. The requested changes are related to the revised analyses, including an expansion of the selective implementation of the Alternative Source Terms (AST) methodology, and the necessary proposed changes to the TSs.

Two changes to the BVPS licensing basis that are not directly reflected in the TSs, but require NRC approval, are an expansion of the selective implementation of the AST methodology of Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors", and use of the 1979 ANS Decay Heat + 2σ model for mass and energy (M&E) releases for a main steamline break outside containment.

To address the accident dose analyses impact of RSG, bounding analyses were performed at 2900 MWt utilizing the AST methodology. To address the M&E releases for main steamline break outside containment a analysis was performed at 2900 MWt utilizing the1979 ANS Decay Heat + 2σ model.

The expansion of the selective implementation AST, as defined in Section 1.2.2 of Regulatory Guide 1.183 includes all accidents impacted by the RSGs. Section 5.11 of Enclosure 2 discusses the impact of RSGs, on the site boundary and control room doses for the applicable accidents listed below.

(a) Control Rod Ejection Accident (CREA)

(b) Main Steam Line Break (MSLB) outside containment

(c) Steam Generator Tube Rupture (SGTR)

(d) Locked Rotor Accident (LRA)

(e) Loss of AC Power (LACP)

(f) Small Line Break (SLB) outside containment

It is noted that the CREA is addressed in this application by reference only, since the accident analysis was performed assuming RSGs and EPU conditions and approved by License Amendment No. 257. The Loss of Coolant Accident (LOCA) and the Fuel Handling Accident (FHA) are not impacted by the RSGs and have been approved for BVPS Unit No. 1 by license amendments 257 and 241, respectively.

Core decay heat generation assumed in calculating the steamline break mass and energy (M&E) releases is based on the 1979 ANS Decay Heat + 2σ model, ANSI/ANS-5.1-1979, "American National Standard for Decay Heat Power in Light Water Reactors," August 1979. The existing analysis assumed the use of the 1971 standard (+20% uncertainty) for the decay heat. The use of the 1979 version represents a deviation from the current licensing-basis MSLB M&E releases outside containment analysis for BVPS Unit No. 1.

The 1979 decay heat model has been previously used by Westinghouse in other analyses for BVPS Unit 1. The analyses are LOCA and MSLB inside containment which are pending NRC approval in a previously submitted BVPS Unit 1 LAR to revise the BVPS Unit 1 containment to an atmospheric design. Use of the model for LOCA M&E releases has been approved by the NRC, i.e., WCAP-10326-A (Nonproprietary), "Westinghouse LOCA Mass & Energy Release Model for Containment Design – March 1979 Version." Use of the model for MSLB outside containment M&E releases is being submitted for NRC review and approval in this RSG LAR. Use of the 1979 model has been approved by the NRC for similar applications on other plants.

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.

The safety and radiological dose consequence analyses confirmed that safety analysis and dose consequence analysis acceptance criteria will be satisfied for the Model 54F BVPS Unit No. 1 replacement steam generators, including changes to reactor core safety limits, reactor trip system (RTS) and

engineered safety features actuation system (ESFAS) setpoints, and other safety analysis inputs related to the proposed changes. The analyses are conservative and bounding with respect to operation with RSGs at the current licensed maximum power level.

For the purpose of this evaluation, the proposed changes to Technical Specifications 3.4.1.3, Reactor Coolant System Shutdown, and 3.4.5, Steam Generators, which will directly address the new Unit No. 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 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 RSGs.

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 RSG 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 RSG tubes.

(c) The third area of change is to update the wording and content of the TS to provide clarification and to incorporate wording enhancements consistent with the updates made to the subject TS for several other plants that have replaced steam generators. An update in this area includes the addition of a "Note" to exempt the RSGs from inservice inspection requirements during the steam generator replacement outage. Since the RSGs 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 TS 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 2900 MWt (which is conservative and bounding for the current licensed power level of 2689 MWt) 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, i.e., TS 3.4.1.3, 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.

Use of the VIPRE computer code and the WRB-2M correlation 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 and correlation are evaluation tools that are independent of the probability of an accident. Use of the code and correlation establish DNB limits such that core damage will not occur during postulated design basis accidents. Thus, use of the code and correlation will not involve a significant increase in the consequences of an accident previously evaluated.

Use of the 1979 ANS Decay Heat + 2σ model for MSLB outside containment M&E releases will not involve a significant increase in the probability or consequences of an accident previously evaluated because the model is not an accident initiator.

The remaining changes, which include the changes to the Overtemperature ΔT and Overpower ΔT equations, the change to the charging pump discharge pressure and the additions of WCAP-14565-P-A and WCAP-15025-P-A to the list of NRC approved methodologies in TS 6.9.5, will not involve a significant increase in the probability or consequences of an accident previously evaluated because none of the changes are accident initiators.

The RSG radiological analysis reflects an expansion of the selective application of the AST methodology and incorporation of the ARCON96 methodology for on-site atmospheric dispersion factors. The radiological analysis concludes that normal operation of BVPS Unit No. 1 with the RSGs with an atmospheric containment will not impact the 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 100 or 10 CFR 50.67, as supplemented by Regulatory Guide 1.183, for the plant operator and the public.

The effects on accident radiation dose considered the replacement of the Unit No. 1 steam generators, a core power level to 2900 MWt, incorporation of the ARCON96 methodology and the expansion of the selective 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 replacement steam generators for Unit No. 1 and the incorporation of the ARCON96 and AST methodologies. These changes were evaluated for their effect 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 or 10 CFR 100.

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 10 CFR 50.67, as supplemented by Regulatory Guide 1.183 or 10 CFR 100.

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.

The areas of changes described previously for the Unit No. 1 RSGs do not adversely 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 identified and 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.

Use of the VIPRE computer code and the WRB-2M correlation at BVPS will not create the possibility of a new or different kind of accident from any accident previously evaluated because the code and correlation are evaluation tools. They are not accident initiators. Thus, their use can not create a new or different kind of accident.

Use of the 1979 ANS Decay Heat + 2σ model for MSLB outside containment M&E releases will not create the possibility of a new or different kind of accident from any accident previously evaluated because the model does not alter how any equipment is operated.

The remaining changes, which include the changes to the Overtemperature ΔT and Overpower ΔT equations, the change to the charging pump discharge pressure and the additions of WCAP-14565-P-A and WCAP-15025-P-A to the list of NRC approved methodologies in TS 6.9.5, will not create the possibility of a new or different kind of accident from any accident previously evaluated because these changes do not alter how any equipment is operated.

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.

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 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 safety analyses for these accidents have been performed at a power level of 2900 MWt (which is conservative and bounding for the current licensed power level of 2689 MWt) 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. 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 TS 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.

Use of the VIPRE computer code and the WRB-2M correlation at BVPS will not involve a significant reduction in a margin of safety because the code and correlation are used to establish a margin of safety previously approved by the NRC such that core damage will not occur.

Use of the 1979 ANS Decay Heat + 2σ model for MSLB outside containment M&E releases will not involve a significant reduction in a margin of safety because the results of the subject accident have been shown to produce acceptable results.

The remaining changes, which include the changes to the Overtemperature ΔT and Overpower ΔT equations, the change to the charging pump discharge pressure and the additions of WCAP-14565-P-A and WCAP-15025-P-A to the list of NRC approved methodologies in TS 6.9.5, will not involve a significant reduction in a margin of safety because they are being made to maintain the existing margin of safety.

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, 10 CFR 100 and 10 CFR 50.67, as supplemented by Regulatory Guide 1.183, will be maintained following approval of the requested changes.

A FENOC assessment of the cumulative effect 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.

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 25), 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
12	Suppression of reactor power oscillations.
13	Instrumentation and control.
14	Reactor coolant pressure boundary
15	Reactor coolant system design
16	Containment design
19	Control room
20	Protection system functions
21	Protection systems reliability and testability
22	Protection system independence

General Design Criteria	
23	Protection system failure modes
24	Separation of protection and control systems
25	Protection system requirements for reactivity control malfunctions
26	Reactivity control system redundancy and capability
29	Protection against anticipated operational occurrences
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
60	Control of releases of radioactive materials to the environment.

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 No. 1 UFSAR.

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

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does 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 amendment meets 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. ANSI/ANS-5.1-1979, "American National Standard for Decay Heat Power in Light Water Reactors," August 1979.
3. FENOC Letter L-05-009, License Amendment Requests 310 and 182, dated February 11, 2005.
4. FENOC Letter L-04-073, License Amendment Requests 317 and 190, dated June 2, 2004.
5. FENOC Letter L-04-124, License Amendment Requests 318 and 191, dated October 4, 2004.
6. WCAP-12945-P-A, Volume 1 (Revision 2) and Volumes 2-5 (Revision 1), "Code Qualification Document for Best Estimate LOCA Analysis," March 1998.
7. FENOC Letter L-04-127, License Amendment Requests 327 and 197, dated October 5, 2004.
8. FENOC Letter L-05-046, Response to Request for Additional Information in Support of LAR Nos. 327 and 197, Steam Generator Allowable Value Setpoint, dated March 22, 2005.
9. NRC Issuance of Amendment letter dated July 30, 2001, Beaver Valley Power Station License Amendments 239 (Unit 1) and 120 (Unit 2).
10. 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.
11. WCAP-11419-P-A, Revision 4, "Westinghouse Setpoint Methodology for Protection Systems – Beaver Valley Power Station Unit 1," March 2004.
12. NUREG-1431, Revision 3, "Standard Technical Specifications Westinghouse Plants," June 2004.
13. EPRI Technical Report No. 1003138, Revision 6, "PWR SG Examination Guidelines," October 2002.
14. NEI 97-06, Revision 1, "Steam Generator Program Guidelines," January 2001.

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

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

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

18. WCAP-10325-P-A (Proprietary) and WCAP-10326-A (Nonproprietary), "Westinghouse LOCA Mass & Energy Release Model for Containment Design – March 1979 Version," May 1983.

19. Westinghouse NSAL-03-9, "Steam Generator Water Level Uncertainties," September 22, 2003.

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

21. 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.

22. NRC Safety Evaluation Report, "Acceptance for Referencing of Licensing Topical Report WCAP-15025-P, Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids (TAC NO. MA1074)," December 1, 1998.

23. Davidson, S. L. (Ed.), "Westinghouse Fuel Criteria Evaluation Process," WCAP-12488-A, October 1994.

24. Letter from H. A. Sepp (Westinghouse) to J. S. Wermiel (NRC), "Fuel Criterion Evaluation Process (FCEP) Notification of the RFA-2 Design, Revision 1 (Proprietary)," LTR-NRC-02-55, November 13, 2002.

25. 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

Attachment A

Beaver Valley Power Station

Proposed Unit No. 1 Technical Specification Changes

License Amendment Request No. 320

The following is a list of the affected pages:

Page	Pending LAR
2-1	
3/4 3-3	327
3/4 3-5	
3/4 3-5a	
3/4 3-18	317 & 327
3/4 3-19a	327
3/4 4-2d	
3/4 4-8	
3/4 4-9	
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3/4 4-10h	
3/4 4-10i	
3/4 5-8	
6-19	310 & 318

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.

Draft page from Unit 1
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(ΔI) channel.

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

$\frac{1}{(1+\tau_4 S)}$ $\frac{1}{(1+\tau_5 S)}$

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 3.3-1 (Continued)

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.

$$\Delta T \le \Delta T_0 \left[K_4 - K_5\left(\frac{\tau_3 S}{1+\tau_3 S}\right) T - K_6 [T - T'']\right] \frac{1}{(1+\tau_5 S)} \frac{1}{(1+\tau_4 S)}$$

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}.

Draft Page reflects changes from Unit 1 LAR 317 and 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
4. STEAM LINE ISOLATION						
a. Manual	2/steam line	1/steam line	2/operating 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 steamline pressure	1, 2, 3(1)	14
e. Steamline Pressure Rate-High Negative	3/loop	2/loop any loop	2/operating 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

Draft page from Unit 1
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~~ greater than or equal 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.

3/4.4.5 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

SURVEILLANCE REQUIREMENTS (Continued)

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.~~

SURVEILLANCE REQUIREMENTS (Continued)

~~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:

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 of the Model 54F steam generators shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality 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.

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

SURVEILLANCE REQUIREMENTS (Continued)

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.~~

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.

SURVEILLANCE REQUIREMENTS (Continued)

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 limit is equal to the 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)[3] 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[3]. Plug on detection 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.

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

~~SURVEILLANCE REQUIREMENTS (Continued)~~

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.~~

~~c) Westinghouse Alloy 800 leak limiting sleeves, WCAP-15919-P, Revision 00.~~[3]

~~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) Applicable only to Cycle 17.~~

~~SURVEILLANCE REQUIREMENTS (Continued)~~

~~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.~~

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

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

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

~~where:~~

V_{URL}	=	~~upper voltage repair limit~~
V_{LRL}	=	~~lower voltage repair limit~~
V_{MURL}	=	~~mid-cycle upper voltage repair limit based on time into cycle~~
V_{MLRL}	=	~~mid-cycle lower voltage repair limit based on V_{MURL} and time into cycle~~

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

~~SURVEILLANCE REQUIREMENTS (Continued)~~

~~Δt~~	~~=~~	~~length of time since last scheduled inspection during which V_{URL} and V_{LRL} were implemented~~
~~CL~~	~~=~~	~~cycle length (the time between two scheduled steam generator inspections)~~
~~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.~~

~~11.~~ ~~(3)~~ ~~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.~~

~~(2) The NDE is the value provided by the NRC in GL 95-05 as supplemented.~~
~~(3) Applicable only to Cycle 17.~~

SURVEILLANCE REQUIREMENTS (Continued)

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.~~

~~SURVEILLANCE REQUIREMENTS (Continued)~~

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

~~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 1×10^{-2}, notify the Commission and provide an assessment of the safety significance of the occurrence.~~

~~c.[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 and inspect additional 2S tubes in this S.G.	C-1	None	N/A	N/A
			C-2	Plug ~~or repair~~ defective 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.

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.

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 B

Beaver Valley Power Station

Proposed Unit No. 1 Technical Specification Bases Changes

License Amendment Request No. 320

The following is a list of the affected pages:

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B 2-1
B 3/4 3-1d
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B 3/4 4-2d
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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.

3/4.3.1 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

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 main steamline break (MSLB). The ESF instrumentation channels which initiate a safety injection signal are shown in Table 3.3-3.

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 leak limiting 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 leak limiting 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). (Reference: WCAP 15919-P and L-04-068).~~

~~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~~

~~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, V_{URL}, is determined from the structural voltage limit by applying the following equation:~~

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

~~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 (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~~

~~BASES~~

~~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):~~

$$\text{Postulated SLB Leakage}_{\text{cycle 17}} = \text{ARC}_{\text{GL 95-05}} + \text{Assumed Leakage}_{0''\text{-}8''<\text{TTS}} + \text{Assumed Leakage}_{8''\text{-}12''<\text{TTS}} + \text{Assumed Leakage}_{>12''<\text{TTS}}$$

~~Where: $\text{ARC}_{\text{GL 95-05}}$ 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).~~

~~BASES~~

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

~~Assumed Leakage $_{0"-8"<TTS}$ 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.

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 (150 gpd per steam generator) 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

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 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.

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.

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

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 the small break loss of coolant accident (SBLOCA)~~are loss of normal feedwater and feedwater line break (FWLB).

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

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. 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

Beaver Valley Power Station

Proposed Unit No. 1 Licensing Requirements Manual Changes

License Amendment Request No. 320

The following is a list of the affected pages:

Page	Pending LAR
3.1-3	
3.9-2	327
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	
6.5-1	

TABLE 3.1-1.a
Combined Overtemperature Delta-T & Overpower Delta-T
Response Times

able represents the maximum allowable plant testing, electronic response time acceptance criteria on measured RTD response time. All listed values are in seconds.

e this table, take the slowest measured RTD response time in a loop, round up to the nearest 1/10 d, 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~~

~~alues are in seconds.~~

Thi
bas

To
sec

*Al

Insert C1-1.

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 ΔT - ΔT Input	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 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 assumed in the safety analysis for the Overtemperature ΔT function:

Pressurizer pressure input: $\leq$ 2.0 seconds.
Neutron detector input (for $f(\Delta I)$ penalty): $\leq$ 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 3.9-1

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	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	

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

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.

Specification 3.1.3.5 Shutdown Rod Insertion Limits

The shutdown rods shall be withdrawn to at least 225 steps.*

Specification 3.1.3.6 Control Rod Insertion Limits

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.*

Specification 3.2.1 Axial Flux Difference

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.

Specification 3.2.2 $F_Q(Z)$ and F_{xy} Limits

$$F_Q(Z) \leq \frac{CF_Q}{P} * K(Z) \qquad \text{for } P > 0.5$$

$$F_Q(Z) \leq \frac{CF_Q}{0.5} * K(Z) \qquad \text{for } P \leq 0.5$$

Where: CF_Q = ~~2.20~~ 2.40 $\qquad P = \frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$

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:

$F_{xy}(RTP) \leq 1.68$ from 1.8 ft. elevation to 2.3 ft. elevation

$F_{xy}(RTP) \leq 1.73$ from 2.3 ft. elevation to 3.7 ft. elevation

$F_{xy}(RTP) \leq 1.79$ from 3.7 ft. elevation to 5.8 ft. elevation

$F_{xy}(RTP) \leq 1.81$ from 5.8 ft. elevation to 7.4 ft. elevation

$F_{xy}(RTP) \leq 1.74$ from 7.4 ft. elevation to 8.9 ft. elevation

$F_{xy}(RTP) \leq 1.60$ from 8.9 ft. elevation to 10.2 ft. elevation

Values 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.

Specification 3.2.3 $F^N_{\Delta H}$

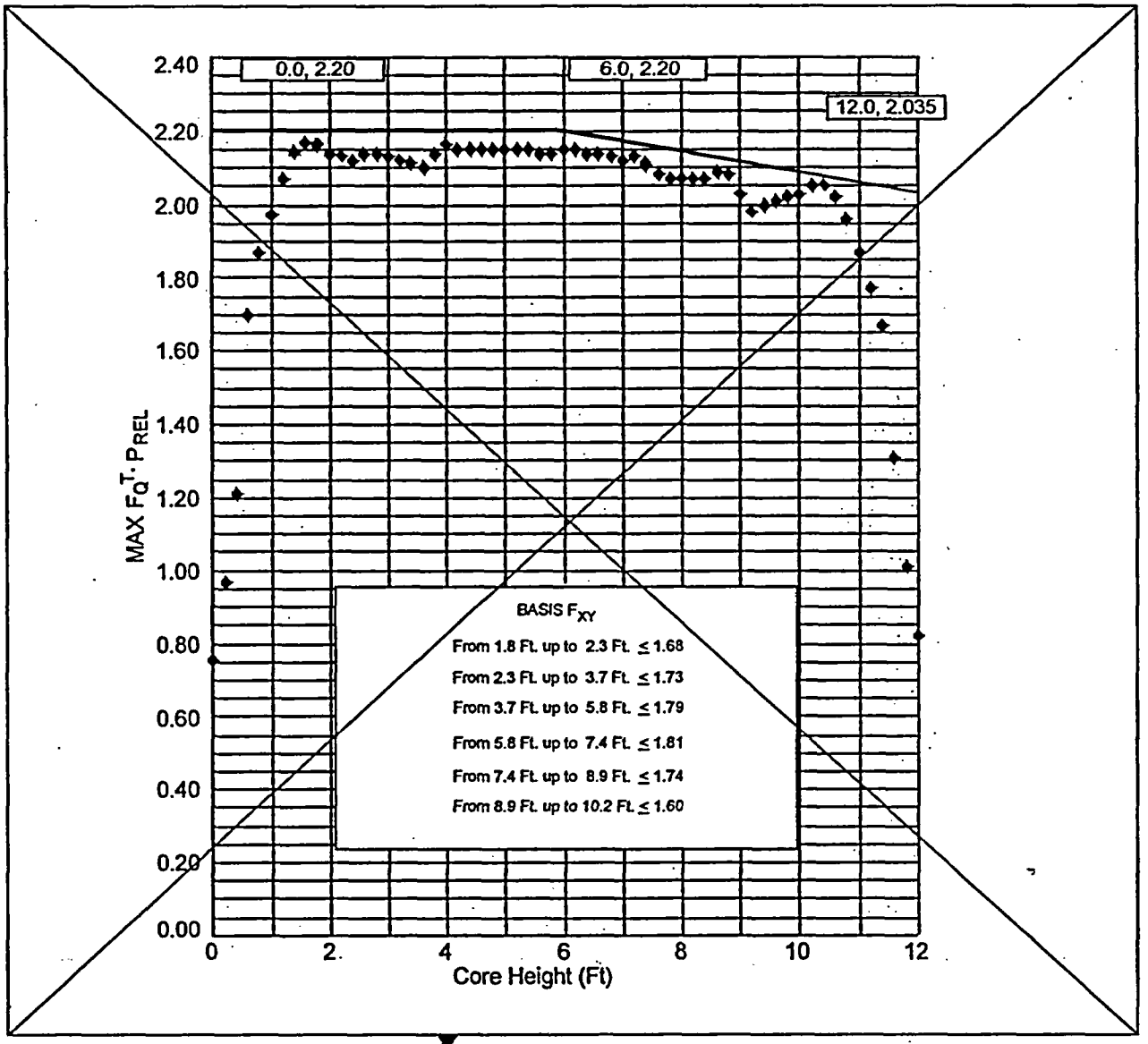
$F^N_{\Delta H} \leq CF_{\Delta H} * (1 + PF_{\Delta H} (1-P))$

Where: $CF_{\Delta H} = 1.62$ for Robust Assemblies and 1.456 for Vantage 5H Assemblies.

$PF_{\Delta H} = 0.3$

$P = \frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$

Provided for Information Only.



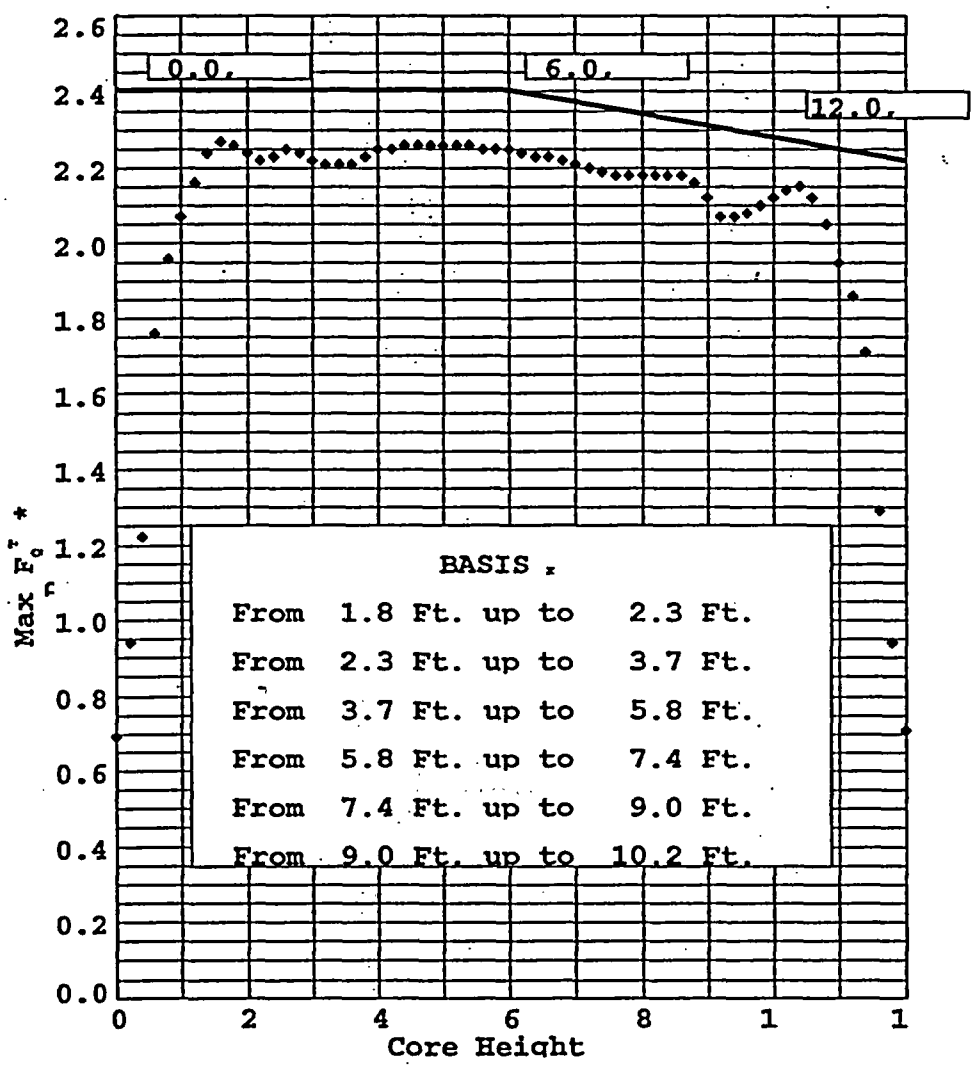
Replace with Insert C1-2.

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 (1)
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:~~

(1) T' represents the cycle-specific Full Power Tavg value used in core design.

~~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 (1)
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

(1) T" represents the cycle-specific Full Power Tavg value used in core design.

Specification 3.2.5 DNB Parameters

Parameter	Indicated Value
Reactor Coolant System Tavg	Tavg ≤ ~~580.0~~ 583.6°F(~~2~~1)
Pressurizer Pressure	Pressure ≥ ~~2215~~ 2218 psia(~~3~~2)
Reactor Coolant System Total Flow Rate	Flow ≥ ~~267,400~~ 267,300 gpm(~~4~~3)

(~~1~~2) The Reactor Coolant System (RCS) T_{avg} value includes allowances for rod control operation and verification via control board indication.

(~~2~~3) The pressurizer pressure value includes allowances for pressurizer pressure control operation and verification via control board indication.

(~~3~~4) 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.

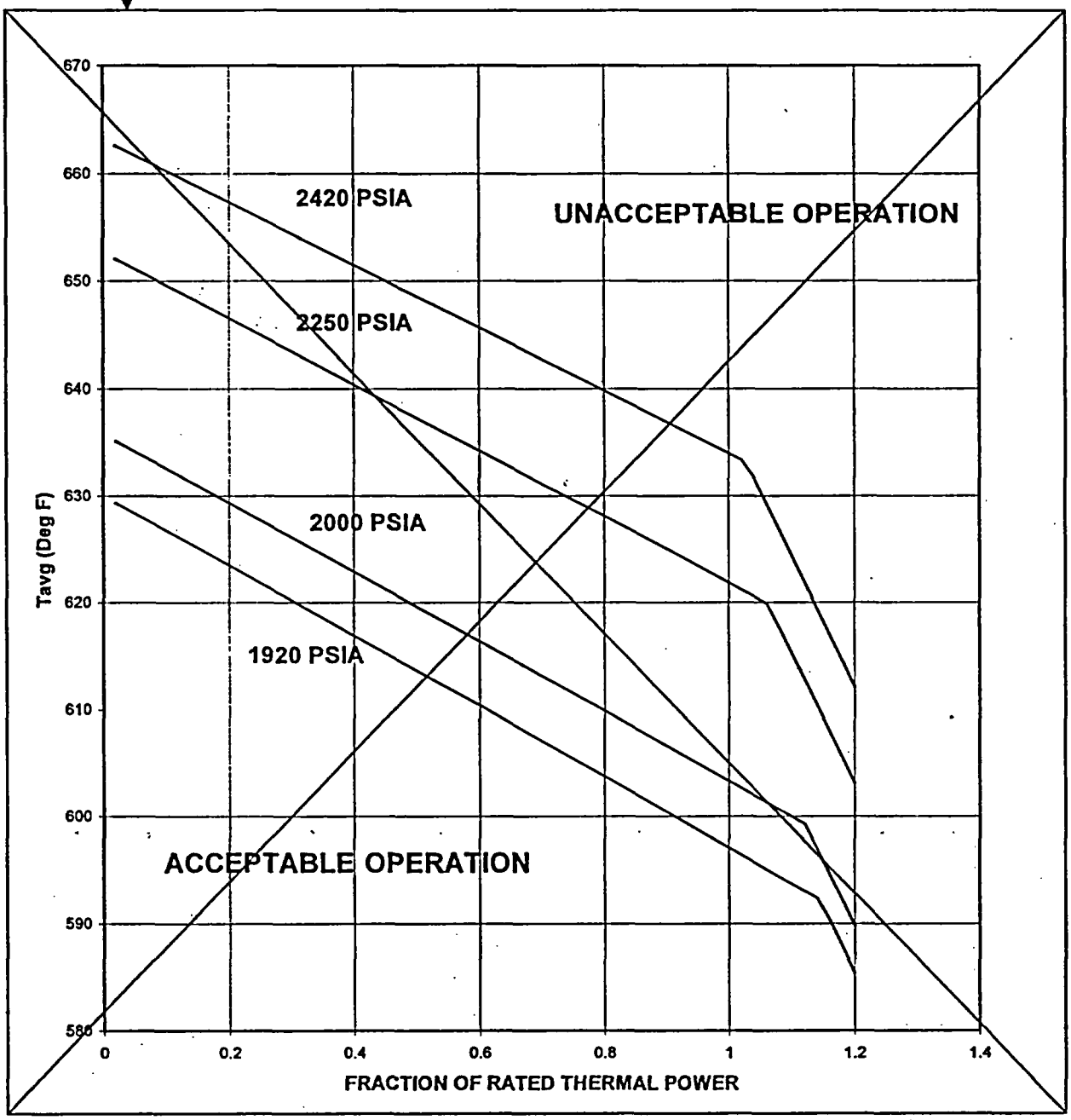
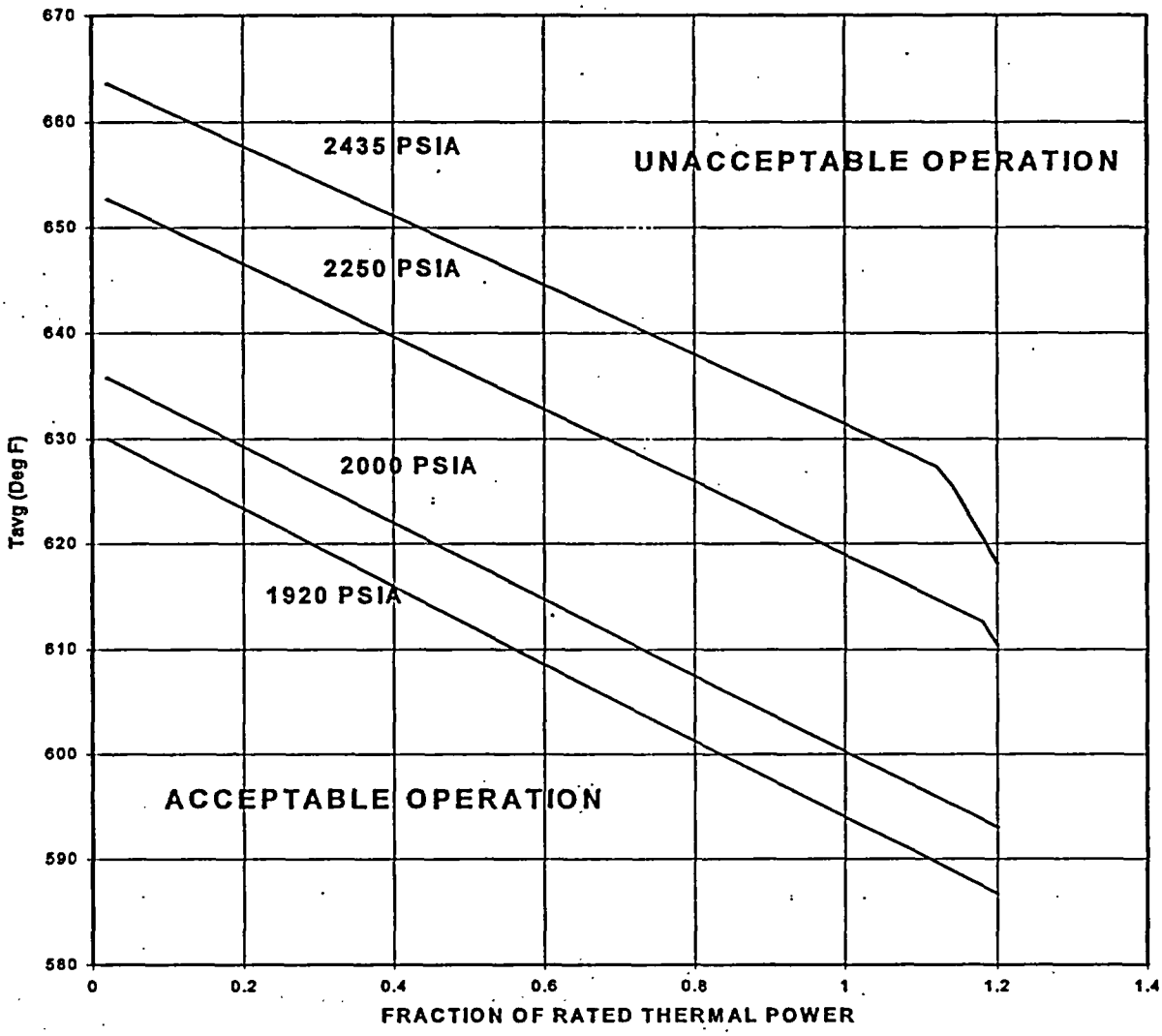


Figure 4.1-5
REACTOR CORE SAFETY LIMIT
THREE LOOP OPERATION
(Technical Specification Safety Limit 2.1.1)

Insert C1-3.



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.

Attachment D

Beaver Valley Power Station

Commitment List

License Amendment Request No. 320

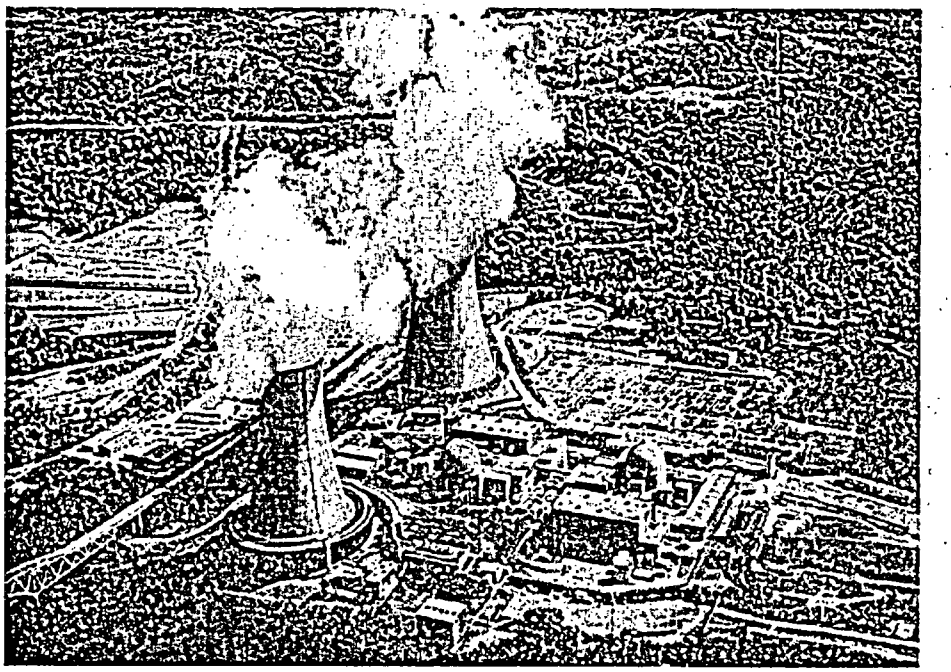
Commitment List

The following table identifies those actions committed to by FirstEnergy Nuclear Operating Company (FENOC) for Beaver Valley Power Station (BVPS) Unit No. 1 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	DUE DATE
1. Implement LAR 317 (Containment Conversion), including plant modification commitments.	Prior to or concurrent with amendment implementation.
2. Implement LAR 318 (BELOCA).	Prior to or concurrent with amendment implementation.
3. Replace the Unit 1 steam generators with Westinghouse Model 54F Replacement Steam Generators, including replacement of level transmitters.	Prior to amendment implementation.
4. Modify the charging pumps by rebalancing injection flows and extending the pump runout limit.	Prior to amendment implementation.
5. Replace or modify the Unit 1 Overtemperature ΔT and Overpower ΔT instrumentation to incorporate lead/lag filters that accommodate the assumed time constants.	Prior to amendment implementation.
6. Submit a license amendment request to adopt steam generator technical specification requirements consistent with Technical Specification Task Force (TSTF) 449, "Steam Generator Tube Integrity.	Within 6 months following the notice of availability for adoption of TSTF-449 is issued under the consolidated line item improvement process (CLIIP).

Enclosure 2

Beaver Valley Power Station Unit 1 Replacement Steam Generator Licensing Report April 2005



FENOC

FirstEnergy Nuclear Operating Company

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LIST OF ACRONYMS

ADV	Main Steam Atmospheric Dump Valves
AEJ	Air Ejector
AFW	Auxiliary Feedwater
AIL	Accident Induced Leakage
AMSAC	Anticipated Mitigating System Actuation Circuitry
ANC	Advanced Nodal Code
ANS	American Nuclear Society
ANSI	American Nuclear Society Institute
AOV	Air Operated Valve
ARC	Alternate Repair Criteria
ASDV	Atmospheric Steam Dump Valve
ASME	American Society of Mechanical Engineers
AST	Alternative Source Term
ATWS	Anticipated Transient Without Scram
B&PV	Boiler and Pressure Vessel (Code)
BEF	Best Estimate Flow
BELOCA	Best Estimate Loss Of Coolant Accident
BOL	Beginning Of Life
BOP	Balance of Plant
BTP	Branch Technical Position
BVPS	Beaver Valley Power Station
°C	Degrees Centigrade
CC	Containment Conversion
CEDE	Committed Effective Dose Equivalent
CFR	Code of Federal Regulations
CIB	Containment Isolation Phase "B"
CIS	Concurrent Iodine Spike
COLR	Core Operating Limits Report
COMS	Cold Overpressure Mitigation System
COSI	Condensation
CR	Control Room
CREA	Control Rod Ejection Accident
CREVS	Control Room Emergency Ventilation System
CSA	Channel Statistical Allowance
CVCS	Chemical and Volume Control System
DBA	Design Basis Accident
DDE	Deep Dose Equivalent
DE	Dose Equivalent
DF	Decontamination Factor
DFBN	Debris Filter Bottom Nozzle
DL	Design Limit

LIST OF ACRONYMS (continued)

DNB	Departure from Nucleate Boiling
DNBR	Departure Nucleate Boiling Ratio
EAB	Exclusion Area Boundary
ECCS	Emergency Core Cooling System
EOL	End Of Life
EPU	Extended Power Uprate
EQ	Equipment Qualification
ERF/TSC	Emergency Response Facility/Technical Support Center
ESF	Engineered Safeguards Features
EγBar	Average Gamma Released per Disintegration
°F	Degrees Fahrenheit
FENOC	FirstEnergy Nuclear Operating Company
FHA	Fuel Handling Accident
Ft	Feet
GPM	Gallons Per Minute
GWD	Gigawatt Days
HFP	Hot Full Power
HHSI	High Head Safety Injection
HP	High Pressure
HZP	Hot Zero Power
IFBA	Integral Fuel Burnable Absorber
IFM	Intermediate Flow Mixing
IRI	Incomplete Rod Insertion
ISI	Inservice Inspection Program
IST	Inservice Testing Program
ΔK/K	Shutdown Margin
kW	Kilowatt
K(Z)	Normalized F_Q as a function of core height
LACP	Loss of AC Power
LAR	License Amendment Request
LCO	Limiting Condition of Operation
LHSI	Low Head Safety Injection
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LPD	Low Pressure Drop
LPZ	Low Population Zone
LR	Locked Rotor

LIST OF ACRONYMS (continued)

LRA	Locked Rotor Accident
LTCC	Long Term Core Cooling
LWR	Liquid Waste Releases
M&E	Mass and Energy
MFW	Main Feedwater
MOV	Motor Operated Valve
MREM	Millirem
MSIV	Main Steam Isolation Valve
MSLB	Main Steamline Break
MSR	Moisture Separator Reheater
MSS	Main Steam System
MSSV	Main Steam Safety Valve
MTC	Moderator Temperature Coefficient
MWD/MTU	Megawatt Days/Metric Ton Uranium
MWe	Megawatts electric
MWt	Megawatts thermal
NG	Noble Gas
NRC	Nuclear Regulatory Commission
NRS	Narrow Range Span
NSSS	Nuclear Steam Supply Systems
ODCM	Offsite Dose Calculation Manual
OL	Operating License
OPΔT	Overpower Delta T
OSG	Original Steam Generator
OTΔT	Overtemperature Delta T
PAOT	Post Accident Operating Time
PCT	Peak Clad Temperature
PCWG	Power Capability Working Group
PERC2	Passive Evolutionary Regulatory Consequence Code
PIS	Pre-Accident Iodine Spike
PORV	Power Operated Relief Valve
PSIA	Pounds per Square Inch – Absolute
PSI	Pound per Square Inch
PSIG	Pounds per Square Inch – Gauge
PWR	Pressurized Water Reactor
QA	Quality Assurance
RCCA	Rod Cluster Control Assemblies
RCP	Reactor Coolant Pump

LIST OF ACRONYMS (continued)

RCS	Reactor Coolant System
RFA	Robust Fuel Assembly
RG	Regulatory Guide
RRB	Reduced Rod Bow
RSG	Replacement Steam Generator
RTDP	Revised Thermal Design Procedure
RTN	Removable Top Nozzle
RTP	Rated Thermal Power
RTS/ESFAS	Reactor Trip System/Engineered Safety Features Actuation System
SAL	Safety Analysis Limit
SBLOCA	Small Break Loss of Coolant Accident
SBO	Station Blackout
SECY	Commission Papers
SER	Safety Evaluation Report
SG	Steam Generator
SGTP	Steam Generator Tube Plugging
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SIS	Safety Injection System
SLB	Small Line Break
SLCRS	Supplementary Leak Collection and Release System
SRP	Standard Review Plan
STDP	Standard Thermal Design Procedure
STP	Standard Temperature & Pressure
TA	Total Allowance
T_{avg}	Temperature Average
TDH	Total Developed Head
TEDE	Total Effective Dose Equivalent
TID	Technical Information Document
U1	Unit 1
U2	Unit 2
UFSAR	Updated Final Safety Analysis Report
V	Volts
VCT	Volume Control Tank
WCAP	Westinghouse Commercial Atomic Power
WGSR	Waste Gas System Rupture

1 INTRODUCTION

The Beaver Valley Power Station Units 1 and 2 (BVPS-1 and BVPS-2) Extended Power Uprate (EPU) License Amendment Request (LAR) Nos. 302/173 include the Technical Specification and analysis methodology changes for operation of BVPS-1 at EPU rated thermal power (RTP) with Model 54F Replacement Steam Generators (RSGs). As such, the EPU analyses form the licensing basis for the BVPS-1 RSGs. FirstEnergy Nuclear Operating Company (FENOC) submitted the EPU LAR in October 2004 and requested NRC approval by November 2005 in order to support implementation of the BVPS-1 RSGs during the 2006 spring outage (1R17).

Schedule delays in FENOC providing the additional information specified in the NRC EPU acceptance review letter dated January 6, 2005 have been encountered such that NRC review and approval of the EPU LAR may not be completed in time to support the BVPS-1 2006 spring outage (1R17). Due to these delays, an alternative approach has been defined to support implementation of the BVPS-1 RSGs during the 2006 spring outage (1R17). This alternative approach consists of submitting this BVPS-1 RSG LAR (No. 320) separate from the EPU LAR but based on the EPU analyses. BVPS-1 RSG LAR No. 320 contains only those Technical Specification and analysis methodology changes that require NRC review and approval to support implementation of the BVPS-1 RSGs and operation of BVPS-1 at the current RTP. This alternative approach reduces the number of Technical Specification changes that require NRC review and approval to support implementation of the BVPS-1 RSGs, and eliminates the need for review and approval of the Technical Specification change for an increase in RTP. By separating the implementation of the BVPS-1 RSGs from the EPU LAR, the NRC review and approval process for the EPU LAR can proceed on a schedule that is independent of the steam generator replacement outage.

This BVPS-1 RSG Licensing Report (Enclosure 2 of BVPS-1 RSG LAR No. 320) provides the technical justification for the Technical Specification and analysis methodology changes contained in BVPS-1 RSG LAR No. 320, including the expansion of selective implementation of Alternative Source Term (AST) methodology for BVPS-1. This BVPS-1 RSG Licensing Report contains the applicable portions of the EPU Licensing Report (i.e., sections, subsections, figures, and tables) that provide the technical justification for the Technical Specification and analysis methodology changes contained in BVPS-1 RSG LAR No. 320.

In order to facilitate NRC review of the information provided in this BVPS-1 RSG Licensing Report as well as comparison to the information in the EPU Licensing Report, this BVPS-1 RSG Licensing Report uses the same format and numbering convention as the EPU Licensing Report. Those portions of the EPU Licensing Report that are included in this BVPS-1 RSG Licensing Report are incorporated with minimal editing, such as removal of analyses and results applicable to BVPS-2. Those portions of the EPU Licensing Report that are not included in this BVPS-1 RSG Licensing Report are designated in this report as "EPU Section" or "EPU Table." The designation "NA" (Not Applicable) has been used in tables to indicate that the information is not applicable to BVPS-1 RSG LAR No. 320. In this manner, this BVPS-1 RSG Licensing Report retains the same format and numbering convention as was used in the EPU Licensing Report.

Those portions of the EPU Licensing Report that are not required to support BVPS-1 RSG LAR No. 320 Technical Specification and analysis methodology changes are not included in this BVPS-1 RSG Licensing Report. The provisions of 10 CFR 50.59 are being used to address EPU analyses that are not

dependent on Technical Specification or analysis methodology changes and, thus, do not require NRC review and approval for RSG implementation. Although this BVPS-1 RSG Licensing Report includes general discussion of the Model 54F RSG component design features and structural integrity, the provisions of 10 CFR 50.59 are being used to address the RSGs as well as the impact of the RSGs on EPU analyses that are not dependent on Technical Specification and analysis methodology changes.

This section provides additional background information regarding the BVPS EPU Project, its relationship with BVPS-1 RSG LAR No. 320, and how the EPU analyses provide technical justification for the Technical Specification and analysis methodology changes contained in BVPS-1 RSG LAR No. 320.

1.1 BACKGROUND

In early 2000, FirstEnergy Nuclear Operating Company (FENOC) implemented a Full Potential Program for Beaver Valley Power Station Units 1 and 2 (BVPS-1 and BVPS-2). The program included the following key objectives for increasing the electrical output (MWe) of BVPS-1 and BVPS-2.

1. Implement an initial measurement uncertainty recapture power uprate to increase the Nuclear Steam Supply Systems (NSSS) power level and increase the value of Beaver Valley Power Station.

2. Implement a larger power uprate to further increase the NSSS power level and maximize the value of Beaver Valley Power Station.

For BVPS-1, the Full Potential Program included the following additional key objectives:

1. Implement a steam generator preventative maintenance program that optimizes the value of BVPS-1 by postponing steam generator replacement.

2. Replace BVPS-1 steam generators when it is the most advantageous to do so.

The initial measurement uncertainty recapture power uprate project was initiated in mid-2000 to increase the reactor power level of BVPS-1 and BVPS-2 by 1.4%, from the original reactor power level of 2652 MWt (2660 MWt NSSS power) to an uprated reactor power level of 2689 MWt (2697 MWt NSSS power). The License Amendment Request (LAR) for the uprate to 2689 MWt reactor power was submitted to the Nuclear Regulatory Commission (NRC) in early 2001 and NRC approval was obtained in mid-2001. The uprate to 2689 MWt reactor power was implemented at BVPS-1 and BVPS-2 in fall 2001.

The larger power uprate project was initiated in mid-2000 in conjunction with initiation of the measurement uncertainty recapture power uprate project. The larger power uprate project included an initial scoping evaluation to provide the information needed to select the power level to which BVPS-1 and BVPS-2 would be uprated. As a result of the scoping evaluation, the reactor power level of 2900 MWt (NSSS power of 2910 MWt) was selected and the Extended Power Uprate (EPU) Project was started. In contrast to the measurement uncertainty recapture power uprate project which consisted primarily of evaluations to show the acceptability of a small increase in power level, the EPU Project

consisted primarily of analyses required to demonstrate the acceptability of operation at the selected power level. Furthermore, where practical and synergistic, the EPU Project included explicit elements to support the steam generator replacement for BVPS-1. The Replacement Steam Generator (RSG) Project for BVPS-1 was in the early definition phase at the time that the EPU Project was started. The Westinghouse Model 54F RSG design was subsequently selected for BVPS-1. The RSG Project included the work scope to design and manufacture the RSGs and to update the EPU Project analyses and evaluations to incorporate the RSG final design.

1.1.1 Uprate Power Level (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

1.1.2 Analysis and Licensing Plan and Implementation Plan

Following the selection of 2900 MWt reactor power (2910 MWt NSSS power) as the uprate power level, the EPU analysis and licensing plan and the EPU implementation plan were defined.

EPU Analysis and Licensing Plan

An analysis and licensing plan was defined for BVPS-1 and BVPS-2 in which analysis would be performed and an EPU LAR would be submitted to the NRC requesting approval to uprate BVPS-1 to the reactor power level of 2900 MWt with the RSGs and to uprate BVPS-2 to the reactor power level of 2900 MWt with the original steam generators (OSGs). For BVPS-1, the EPU LAR would incorporate the impact of the RSGs on applicable plant analytical areas, including the NSSS design parameters, NSSS design transients, NSSS and BOP systems, NSSS components, reactor coolant loop, main steam and main feedwater piping, safety (accident) analyses and nuclear fuel. The EPU LAR would also include the Technical Specification changes associated with the BVPS-1 RSGs. The analyses for the BVPS-1 RSG components, including the ASME Code structural analysis, would be performed separately and addressed under the provisions of 10 CFR 50.59.

In order to facilitate the preparation, submittal and review of licensing documentation required for EPU, the licensing plan defined a staged approach consisting of the following LARs:

1. A Containment Conversion (CC) LAR consisting of the containment-related analyses and evaluations required to support conversion of the containment design basis from sub-atmospheric to atmospheric. The analyses and evaluations would be performed at the EPU power level. The LAR would be submitted to the NRC for review and approval prior to the other LARs.

2. A Best Estimate Loss of Coolant Accident (BELOCA) LAR consisting of the large break LOCA analyses and evaluations required to support EPU. These analyses and evaluations would be performed at the EPU power level. The LAR would be limited to BELOCA analyses and evaluations consistent with accepted licensing practice and would be submitted to the NRC for review and approval in conjunction with the EPU LAR.

3. An EPU LAR consisting of the remaining analyses and evaluations required to support EPU. These analyses and evaluations would be performed at the EPU power level. The LAR would be

submitted to the NRC for review and approval and would contain the request to uprate the rated thermal power (RTP) of BVPS-1 and BVPS-2 to 2900 MWt.

The analysis and licensing plan supports completion of analyses and submittal of the EPU LAR to the NRC in 2004 requesting approval in 2005 to support a staged implementation of EPU starting in 2006.

EPU Implementation Plan

The implementation plan defined for BVPS-1 and BVPS-2 consists of a staged implementation of EPU to the reactor power level of 2900 MWt (2910 MWt NSSS power). Following NRC review and approval of the EPU LAR, FENOC will complete the implementation of safety-related equipment modifications and Technical Specification changes required to support operation under the EPU LAR analyses. Following confirmation of all safety-related analysis inputs, the EPU LAR analyses will be implemented as the analysis of record (AOR) for BVPS-1 and BVPS-2 and be used as the analytical basis for implementing the BVPS-1 RSGs. However, FENOC will continue to operate BVPS-1 and BVPS-2 at the current reactor power level of 2689 MWt (2697 MWt NSSS power) until the non-safety-related BOP equipment modifications that are needed to support operation at higher power are implemented.

The principal modifications planned to support implementation of the EPU LAR analyses include:

1. Containment Conversion from a sub-atmospheric to an atmospheric design basis including related modifications such as the addition of feedwater isolation valves (FIVs) and auxiliary feedwater flow limiting venturies for BVPS-1

2. Replacement charging/safety injection pump rotating assemblies

3. Replacement steam generators for BVPS-1

The principal modifications planned to support operation at higher power include:

1. BOP replacement high pressure (HP) all-reaction turbines
2. BOP electrical transformer modifications
3. BOP main condenser modifications for BVPS-2
4. BOP cooling tower modifications for BVPS-2
5. BOP moisture separator reheater (MSR) relief valve modifications
6. BOP main feedwater control valve (FCV) trim modifications
7. BOP heater drain control valve modifications
8. BOP instrument replacements

BVPS-1 RSG Alternative Approach

As discussed above under the EPU Implementation Plan, the BVPS-1 RSGs are one of the principal BVPS-1 modifications to be implemented prior to implementation of the EPU LAR analyses. Consistent with the staged implementation plan, FENOC intends to initially operate BVPS-1 at the current reactor power level with the RSGs until the remaining modifications are made to support operation at the higher power level.

The EPU LAR analyses for BVPS-1 include consideration of the BVPS-1 RSGs as well as other plant configuration and Technical Specification changes needed to support the EPU LAR analyses. In this way the EPU LAR analyses form the licensing basis analyses for the BVPS-1 RSGs.

An alternative approach for implementation of the BVPS-1 RSGs and operation of BVPS-1 at the current reactor power level with the RSGs is to submit a BVPS-1 RSG LAR separate from the EPU LAR but based on the EPU analyses. The BVPS-1 RSG LAR contains only those Technical Specification and analysis methodology changes that require NRC review and approval to support implementation of the BVPS-1 RSGs, expansion of selective implementation of AST, and operation of BVPS-1 at the current reactor power level.

The analyses that are not dependent on Technical Specification or analysis methodology changes do not require NRC review and approval and are being addressed through the provisions of 10 CFR 50.59. Analyses in this category include the analyses for the BVPS-1 RSG components, including the ASME Code structural analysis, and analyses performed in the systems, components, safety, and fuel areas to incorporate the operating conditions and characteristics associated with the BVPS-1 RSGs.

The BVPS-1 RSG LAR approach reduces the number of Technical Specification changes that need NRC review and approval, and eliminates the need for review and approval of the Technical Specification change for an increase in rated thermal power. This alternative approach for implementation of the BVPS-1 RSGs is being pursued because delays have been encountered in the NRC review and approval process for the EPU LAR.

The BVPS-1 RSG LAR approach takes credit for the implementation of the CC and BELOCA LARs and the principal modifications planned to support implementation of the EPU LAR analyses, which include:

1. Containment Conversion from a sub-atmospheric to an atmospheric design basis including related modifications such as the addition of feedwater isolation valves (FIVs) and auxiliary feedwater flow limiting venturies for BVPS-1

2. Replacement charging/safety injection pump rotating assemblies

1.2 PURPOSE

The purpose of the BVPS-1 RSG LAR is to submit for NRC review and approval those portions of the EPU LAR that are required to implement the BVPS-1 RSGs and operate BVPS-1 at the current reactor power of 2689 MWt (2697 MWt NSSS power). The NSSS design (PCWG) parameters established for operation of BVPS-1 at the current reactor power with RSGs include the following conditions:

1. The current reactor power of 2689 MWt (NSSS power of 2697 MWt)
2. The current full power reactor vessel average temperature of 576.2°F
3. The current full power feedwater temperature of 439.3°F
4. A steam generator tube plugging level range of 0% to 22%

These NSSS design (PCWG) parameters established for operation at current power conditions are bounded by the NSSS design (PCWG) parameters established for operation of BVPS-1 at EPU reactor power with RSGs, which include the following conditions:

1. An uprated reactor power of 2900 MWt (NSSS power of 2910 MWt)
2. A full power reactor vessel average temperature (T_{avg}) range of 566.2° to 580°F
3. A full power feedwater temperature range of 400° to 455°F
4. A steam generator tube plugging level range of 0% to 22%

1.3 SCOPE

The BVPS-1 RSG LAR contains only those Technical Specification and analysis methodology changes required to support implementation of the BVPS-1 RSGs and operation of BVPS-1 at the current reactor power level. The BVPS-1 RSG Licensing Report provides the technical justification for the Technical Specification and analysis methodology changes that are contained in the BVPS-1 RSG LAR. The technical justification is based on EPU analyses that include consideration of the BVPS-1 RSGs and that bound and support operation of BVPS-1 at current power conditions with the RSGs. The BVPS-1 RSG LAR Technical Specification changes fall into two categories; changes required due to the RSG components and changes required to use the EPU analyses as the basis for implementation and operation with the RSGs. The BVPS-1 RSG Licensing Report also contains the technical justification for expansion of selective implementation of Alternative Source Term (AST) methodology. Therefore, the BVPS-1 RSG Licensing Report contains the technical justification for Technical Specification and analysis methodology changes that deviate from the current license basis and, hence, cannot be performed under 10 CFR 50.59. Specifically, the BVPS-1 RSG Licensing Report includes technical justification for the following items:

1. Technical Specification changes for RSG inspection surveillance requirements

2. Technical Specification changes for Reactor Trip System and Engineered Safety Feature Actuation System RSG water level functions

3. Technical Specification change for RSG water level operability surveillance requirement during plant shutdown

4. Technical Specification changes for adding ΔT lag compensators to the Reactor Trip System Overtemperature ΔT and Overpower ΔT functions

5. Technical Specification changes for using the WRB-2M correlation and VIPRE computer code in analyses for Robust Fuel Assemblies (RFA), including RFA-2 fuel

6. Technical Specification change for raising the minimum charging pump discharge pressure surveillance requirement associated with reactor coolant pump seal injection flow

7. Expansion of selective implementation of AST for BVPS-1

The BVPS-1 RSG Licensing Report contains the applicable portions of the EPU Licensing Report (i.e., sections, subsections, figures, and tables) that provide the technical justification for the Technical Specification and analysis methodology changes contained in the BVPS-1 RSG LAR. In order to maintain continuity between licensing reports, the BVPS-1 RSG Licensing Report uses the same format and numbering as used for the EPU Licensing Report. Those portions of the EPU Licensing Report that are not included in the BVPS-1 RSG Licensing Report are designated in the BVPS-1 RSG Licensing Report as "EPU Section" or "EPU Table." The information contained in the BVPS-1 RSG Licensing Report has been edited to remove the EPU analyses and results applicable for BVPS-2. The designation "NA" (Not Applicable) has been used in tables to indicate that the information is not applicable to the BVPS-1 RSG LAR. In this manner, the BVPS-1 RSG Licensing Report retains the same format and numbering convention as was used in the EPU Licensing Report.

1.4 REVIEW PROCESS

1.4.1 Input Parameters and Assumptions

Comprehensive analysis input parameter lists were developed at the beginning of the EPU Project for the various analytical areas within the work scope of the project. These lists were used to identify the input parameter and assumption requirements and to obtain FENOC input data and approval. In conjunction with development of the individual input parameter lists, a consolidated input parameter list was prepared to aid in the identification and control of input data and assumptions and to promote consistency across the various analytical areas within the EPU Project.

The EPU analyses were performed to reflect the as-built and as-operated plant. Plant drawings (as built) and/or plant documentation were obtained from FENOC and used as appropriate.

1.4.2 Methodologies and Computer Codes

The Updated Final Safety Analysis Report (UFSAR) analyses contained in the BVPS-1 RSG LAR used methodologies and computer codes that have been previously approved by the NRC or that are consistent with accepted industry practice. The NRC approved analytical techniques (methodology and codes) used for BVPS-1 RSG UFSAR analyses are the same as those used for current analyses for BVPS-1 as described in the associated UFSAR, except for the following areas where NRC generically approved methodology and/or codes were applied to the Beaver Valley Power Station for the first time.

1. Large Break Loss of Coolant Accident (LOCA) analysis used the Best-Estimate LOCA (BELOCA) methodology and the WCOBRA/TRAC computer code. This methodology and computer code have been approved on a generic basis by the NRC and have been applied to a number of plants which have received NRC approval. Consistent with the approach used in the Byron/Braidwood power uprate project, the BELOCA analysis for BVPS-1 at EPU conditions has been submitted to the NRC for review and approval in a BELOCA LAR separate from the EPU LAR and BVPS-1 RSG LAR.

2. Non-LOCA and Fuel Thermal-Hydraulic Design analyses used the VIPRE computer code for the calculation of DNBR. This code has been approved on a generic basis by the NRC and has been applied to a number of plants which have received NRC approval.

3. Fuel Thermal-Hydraulic Design analysis used the WRB-2M correlation for the calculation of DNBR for RFA fuel (including RFA-2 fuel). This correlation has been approved on a generic basis by the NRC and has been applied to a number of plants which have received NRC approval.

4. Main Steamline Break (MSLB) Mass and Energy (M&E) Releases analysis for outside containment used the currently approved LOFTRAN computer code but the decay heat model has been changed to the 1979 ANS Decay Heat +2σ standard decay heat model. This decay heat model has been previously used by Westinghouse in other analyses for the Beaver Valley Power Station including the MSLB M&E releases inside containment analysis previously submitted to the NRC for review and approval as part of the Containment Conversion LAR. This decay heat model has been approved by the NRC for similar applications on other plants.

5. As part of expanding the selective implementation of the Alternative Source Terms (AST) for BVPS-1 in accordance with Regulatory Guide 1.183, the post-accident site boundary and control room dose analyses supporting this application are based on AST methodology. The newly calculated control room atmospheric dispersion factors utilized in the dose consequence analyses were developed using NRC sponsored computer code ARCON96.

Table 1.0-2 lists the principal computer codes used to support the BVPS-1 RSG UFSAR analyses. The table shows which codes have been previously approved and used for BVPS-1 and identifies which codes are being applied to BVPS-1 for the first time. As shown in Table 1.0-2, the principal computer codes being applied to BVPS-1 as part of the BVPS-1 RSG UFSAR analyses have been previously approved by the NRC or are consistent with accepted industry practice. NRC approved computer codes are used within any restrictions and limitations identified in the NRC safety evaluations for the topical reports relative to the computer codes and methodologies.

1.4.3 Proprietary Information Designations

The RSG Licensing Report contains Westinghouse proprietary information. The specific information is contained within brackets with designated superscripted lower case letters. Westinghouse proprietary information is provided in WCAP-16307-P, "Beaver Valley Power Station Extended Power Uprate Licensing Report Supplemental Information."

1.5 TECHNICAL BASIS FOR LICENSE AMENDMENT REQUEST

The Technical Basis for the BVPS-1 RSG LAR is contained in the BVPS-1 RSG Licensing Report. The BVPS-1 RSG LAR includes documentation supporting the required changes to the Technical Specifications and Licensing Requirements Manual.

1.6 CONCLUSIONS

The analyses and evaluations contained in the BVPS-1 RSG Licensing Report support the BVPS-1 RSG LAR Technical Specification changes and demonstrate that operation of BVPS-1 at the reactor power level of 2689 MWt (NSSS power of 2697 MWt) with the RSGs is in compliance with applicable licensing criteria and requirements.

Table 1.0-1
Comparison of Power Levels for Comparable 3-Loop Plants (EPU Table)

(This table number is included to maintain numbering consistency with the EPU Licensing Report. The information in this table is not applicable for the RSG Licensing Report.)

Table 1.0-2
Principal Computer Codes Used to Support RSG LAR UFSAR Analyses

Licensing Report Section No.	Licensing Report Section Title	Principal Computer Codes Used to Support UFSAR Analyses	
		Current	RSG LAR
3.0	NSSS SYSTEMS	-	-
3.2	NSSS Control Systems	LOFTRAN	LOFTRAN
5.0	SAFETY ANALYSIS	-	-
5.2.1	Large Break LOCA	SATAN REFLOOD COCO BASH	WCOBRA/TRAC[5]
5.2.2	Small Break LOCA	NOTRUMP LOCTA-IV	NOTRUMP LOCTA-IV
5.3	Non-LOCA Transients	LOFTRAN FACTRAN TWINKLE THINC	LOFTRAN FACTRAN TWINKLE VIPRE[1]
5.4	Steam Generator Tube Rupture	LOFTTR2[2]	NA
5.6.2	MSLB Mass and Energy Releases Outside Containment	LOFTRAN	LOFTRAN
5.7	LOCA Hydraulic Forces	MULTIFLEX 1.0/3.0 LATFORC FORCE2 THRUST	NA
5.11	Radiological Assessments	RADIOISOTOPE ARCON96[3][4] PERC2 SW-QADCGGP ACTIVITY 2 ION EXCHANGER QADMOD TRAILS_PC ORIGEN-S PAVAN_PC SCALE 4.3 SWNAUA LOCTIC GAMATRANI	RADIOISOTOPE ARCON96[3][4] PERC2 SW-QADCGGP ACTIVITY 2 ION EXCHANGER QADMOD PERC2 ORIGEN-S PAVAN_PC SCALE 4.3 SWNAUA LOCTIC GAMATRANI
6.0	FUEL ANALYSIS	-	-
6.1	Fuel Thermal-Hydraulic Design	THINC PAD 4.0	VIPRE[1] PAD 4.0
6.2	Fuel Nuclear Core Design	PHOENIX-P/ANC	NA
6.3	Fuel Rod Design and Performance	PAD 3.4/4.0	NA

Table 1.0-2 (continued)
Principal Computer Codes Used to Support RSG LAR UFSAR Analyses

Licensing Report Section No.	Licensing Report Section Title	Principal Computer Codes Used to Support UFSAR Analyses	
		Current	RSG LAR
6.4	Reactor Internals Heat Generation Rates	DORT(3)	NA
6.5	Neutron Fluence	DORT(3)	NA

Notes:

(1) First time application of NRC approved code to BVPS-1. Refer to licensing report section for WCAP references.

(2) Applicable to BVPS-2.

(3) Industry Accepted Code.

(4) Submitted in Containment Conversion LAR.

(5) First time application of NRC approved code to BVPS-1. Submitted in BELOCA LAR.

2 NSSS ANALYSIS

The EPU Project included analyses and evaluations to develop the Nuclear Steam Supply System (NSSS) parameters and the NSSS and auxiliary equipment design transients associated with operation at EPU conditions. This information is used as input to EPU Project analyses and evaluations in other analytical areas.

The analyses and evaluations presented in this section support operation of BVPS-1 at EPU conditions with the Model 54F replacement steam generators (RSGs). The analyses and evaluations for EPU conditions bound and support operation at the current power level.

2.1 NUCLEAR STEAM SUPPLY SYSTEM (NSSS) PARAMETERS

The NSSS parameters include NSSS design parameters and NSSS best estimate parameters. The NSSS design parameters are also referred to as Power Capability Working Group (PCWG) parameters. The NSSS design (PCWG) parameters provide bounding parameter values for Reactor Coolant System (RCS) and secondary system conditions (e.g., temperatures, pressures, and flows) for use in developing conservative analyses relative to power uprate conditions. The NSSS best estimate parameters provide best estimate parameters at potential NSSS operating points within the NSSS design (PCWG) parameter ranges. These are used in analyses that require specific operating point parameters, such as analyses and evaluations for sizing modifications to the turbine/generator at power uprate conditions.

2.1.1 NSSS Design (PCWG) Parameters

2.1.1.1 Introduction

The NSSS design (PCWG) parameters are the fundamental parameters that are used as input in all the NSSS analyses. They provide the Reactor Coolant System (RCS) and secondary system conditions (temperatures, pressures, flows) that are used as the basis for the NSSS design transients, systems, components, accidents, and fuel analyses and evaluations.

The PCWG parameters are established using conservative assumptions in order to provide bounding conditions appropriate for the NSSS analyses. For example, the assumed RCS flow in generating the primary and secondary side conditions is the Thermal Design Flow (TDF), which is a conservatively low flow that accounts for flow measurement uncertainty and bounds the maximum expected steam generator tube plugging (SGTP) levels.

In order to predict primary and secondary side conditions that bound the way the plant operates, a range of conditions was established for the vessel average temperature (T_{avg}) (i.e., RCS average temperature), feedwater temperature, and SGTP level. The T_{avg} range was specified between 566.2° and 580°F, the feedwater temperature range between 400° and 455°F, and the SGTP level between 0% and 22%.

The PCWG parameters were developed for BVPS-1 with Model 54F replacement steam generators at the NSSS power level of 2910 MWt (reactor power of 2900 MWt), which constitutes a 9.4% EPU with respect to the original NSSS power level of 2660 MWt (reactor power of 2652 MWt).

To support the staged implementation of EPU at BVPS-1, PCWG parameters were also developed for the current NSSS power level of 2697 MWt (reactor power of 2689 MWt). These PCWG parameters used the current T_{avg} of 576.2°F, the current feedwater temperature of 439.3°F, and the SGTP range of 0 to 22%. These PCWG parameters will define the design conditions that apply to operation of BVPS-1 at the current NSSS power level of 2697 MWt (reactor power of 2689 MWt).

2.1.1.2 Input Parameters and Assumptions

The major input parameters and assumptions used in the calculation of the PCWG parameters for BVPS-1 at the NSSS power level of 2910 MWt are summarized below:

- The power level for the EPU was set at 2910 MWt NSSS (2900 MWt reactor). This is 9.4% higher than the original NSSS power rating of 2660 MWt (2652 MWt reactor).
- The EPU power level includes a net RCS heat input of 10 MWt.
- The current TDF of 87,200 gpm/loop was maintained.
- The PCWG parameters support operation with RFA fuel (including RFA-2) with IFMs.
- Design core bypass flow is 6.5%.
- A range of SGTP level from 0% to 22% is selected for the analyses.
- A range of full-power normal operating T_{avg} from 566.2° to 580.0°F is selected for the analyses.
- A range of full-power feedwater temperature from 400° to 455°F is selected for the analyses.
- The PCWG parameters support Model 54F replacement steam generators for BVPS-1.
- Design moisture carryover (MCO) is 0.10% for the BVPS-1 Model 54F replacement steam generators.

2.1.1.3 Description of Analyses and Evaluations

Table 2.1.1-1 provides the PCWG parameter cases for the original NSSS power level of 2660 MWt and for the current operation NSSS power level of 2697 MWt which reflects a 1.4% power uprating relative to the original NSSS power level. These PCWG parameter cases reflect the original steam generators and are provided for comparison purposes.

Table 2.1.1-2 provides the PCWG parameter cases which were generated and used as the basis for the EPU analyses and evaluations.

Table 2.1.1-2 lists the parameters for BVPS-1 and reflects the Model 54F replacement steam generators. These parameters incorporate the NSSS power level of 2910 MWt, 0 and 22% SGTP, T_{avg} range from

566.2° to 580°F, and feedwater temperature range from 400° to 455°F. The Best Estimate Flow (BEF) range defined for BVPS-1 with Model 54F replacement steam generators is 90,800 to 97,800 gpm/loop.

These performance capability parameters were used in the EPU analytical efforts. Analyses and evaluations based on the parameter set or sets which were most limiting were performed, so that the analyses would support operation of BVPS-1 over the range of conditions specified, including operation of BVPS-1 with Model 54F replacement steam generators.

Table 2.1.1-4 lists the parameters for BVPS-1 with Model 54F replacement steam generators for the current NSSS power level of 2697 MWt (reactor power of 2689 MWt). These parameters incorporate the current T_{avg} of 576.2°F, the current feedwater temperature of 439.3°F, and the SGTP range of 0 to 22%.

These performance capability parameters for the current power level were developed to support the staged implementation of EPU. These PCWG parameters will define the design conditions that apply to operation of BVPS-1 at the current NSSS power level of 2697 MWt (reactor power of 2689 MWt). A comparison of the current power PCWG parameters in Table 2.1.1-4 to the EPU PCWG parameters in Tables 2.1.1-2 shows that the parameters for the current power level are bounded by the parameters for EPU. Thus, the analyses and evaluations performed based on the most limiting set or sets of EPU PCWG parameters in Tables 2.1.1-2 bound and support operation of BVPS-1 at the current power PCWG parameters in Tables 2.1.1-4.

2.1.1.4 Acceptance Criteria and Results

The primary acceptance criteria for the determination of the PCWG parameters is that the parameters must provide adequate flexibility and margin for plant operation, while at the same time bound the range of expected operating conditions. These parameters form the basis for the subsequent analyses and evaluations contained in this report.

2.1.1.5 Conclusions

The PCWG parameters for the EPU Project incorporate the selected power level and range of conditions. PCWG parameter sets were developed for BVPS-1 at the NSSS power level of 2910 MWt (reactor power at 2900 MWt) with Model 54F replacement steam generators. The PCWG parameters were used in EPU Project analyses and evaluations as described in this report.

To support the staged implementation of EPU, PCWG parameters were also calculated for the current NSSS power level of 2697 MWt (reactor power at 2689 MWt) to define the design conditions that will apply to operation of BVPS-1. A comparison of the PCWG parameters for the current power level to the PCWG parameters for EPU showed that the parameters for the current power level are bounded by the parameters for EPU. Thus, the analyses and evaluations performed for EPU based on the most limiting set or sets of EPU PCWG parameters bound and support operation of BVPS-1 at the PCWG parameters associated with the current power level.

Table 2.1.1-1
NSSS Design (PCWG) Parameters
Original and Current Operation

THERMAL DESIGN PARAMETERS	Original Design	Current Operation (1.4% Uprating)	
		Case 1	Case 2
NSSS Power %	100	101.4	101.4
MWt	2660	2697	2697
10^6 BTU/hr	9079	9203	9203
Reactor Power MWt	2652	2689	2689
10^6 BTU/hr	9051	9175	9175
Thermal Design Flow, loop gpm	88,500	87,200	87,200
Reactor 10^6 lb/hr	100.8	99.5	99.5
Reactor Coolant Pressure, psia	2250	2250	2250
Core Bypass, %	4.5	6.5	6.5
Reactor Coolant Temperature, °F			
Core Outlet	612.8	615.1	615.1
Vessel Outlet	609.9	610.8	610.8
Core Average	579.3	580.3	580.3
Vessel Average	576.2	576.2	576.2
Vessel/Core Inlet	542.5	541.6	541.6
Steam Generator Outlet	542.3	541.3	541.3
Steam Generator			
Steam Temperature, °F	516.8	519.0	505.5(1)
Steam Pressure, psia	790	806	716(1)
Steam Flow, 10^6 lb/hr total	11.61	11.81	11.78
Feed Temperature, °F	437.5	439.3	439.3
Moisture, % max.	0.25	0.25	0.25
Tube Plugging Level (%)	0	0	30
Zero Load Temperature, °F	547	547	547
HYDRAULIC DESIGN PARAMETERS			
Mechanical Design Flow, loop gpm	101,400	101,400	
Minimum Measured Flow, gpm/total	Not Applicable	266,800	

Note:
(1) Steam conditions are limited to minimums of 760 psia and 512.3°F due to component design transient considerations.

Table 2.1.1-2
BVPS-1 NSSS Design (PCWG) Parameters
Extended Power Uprate/Model 54F RSGs

THERMAL DESIGN PARAMETERS	Case 1	Case 2	Case 3	Case 4
NSSS Power %	109.4	109.4	109.4	109.4
MWt	2910	2910	2910	2910
10^6 BTU/hr	9929	9929	9929	9929
Reactor Power MWt	2900	2900	2900	2900
10^6 BTU/hr	9895	9895	9895	9895
Thermal Design Flow, loop gpm	87,200	87,200	87,200	87,200
Reactor 10^6 lb/hr	101.1	101.1	99.3	99.3
Reactor Coolant Pressure, psia	2250	2250	2250	2250
Core Bypass, %	6.5	6.5	6.5	6.5
Reactor Coolant Temperature, °F				
Core Outlet	608.6	608.6	621.4	621.4
Vessel Outlet	603.9	603.9	617.0	617.0
Core Average	570.6	570.6	584.6	584.6
Vessel Average	566.2	566.2	580.0	580.0
Vessel/Core Inlet	528.5(1)	528.5(1)	543.1	543.1
Steam Generator Outlet	528.2	528.2	542.8	542.8
Steam Generator				
Steam Temperature, °F	500.5(2)	490.2(2)	515.8(3)	505.6
Steam Pressure, psia	684(2)	623(2)	783(3)	716
Steam Flow, 10^6 lb/hr total	12.02/12.97	12.01/12.95	12.06/13.01(3)	12.03/12.98
Feed Temperature, °F	400/455	400/455	400/455	400/455
Moisture, % max.	0.10	0.10	0.10	0.10
Tube Plugging Level (%)	0	22(4)	0	22(4)
Zero Load Temperature, °F	547	547	547	547
HYDRAULIC DESIGN PARAMETERS				
Mechanical Design Flow, loop gpm	101,400			
Minimum Measured Flow, gpm/total	266,800			

Note:

(1) Vessel inlet temperature is limited to a minimum of 530°F due to reactor vessel embrittlement considerations.

(2) Steam conditions are limited to minimums of 700 psia and 503.1°F due to component design transient considerations.

(3) For analysis purposes, maximum steam conditions are 831 psia, 522.6°F and 13.04 x 10^6 lb/hr.

(4) Steam generator tube plugging is limited to 10% due to Small Break LOCA Analysis.

Table 2.1.1-3
BVPS-2 NSSS Design (PCWG) Parameters
Extended Power Uprate/OSGs (EPU Table)

(This table number is included to maintain numbering consistency with the EPU Licensing Report. The information in this table is not applicable for the RSG Licensing Report.)

Table 2.1.1-4
BVPS-1 NSSS Design (PCWG) Parameters
Current Power/Model 54F RSGs

THERMAL DESIGN PARAMETERS	Case 1	Case 2
NSSS Power		
MWt	2697	2697
10^6 BTU/hr	9203	9203
Reactor Power MWt	2689	2689
10^6 BTU/hr	9175	9175
Thermal Design Flow, loop gpm	87,200	87,200
Reactor 10^6 lb/hr	99.45	99.45
Reactor Coolant Pressure, psia	2250	2250
Core Bypass, %	6.5	6.5
Reactor Coolant Temperature, °F		
Core Outlet	615.1	615.1
Vessel Outlet	610.8	610.8
Core Average	580.3	580.3
Vessel Average	576.2	576.2
Vessel/Core Inlet	541.6	541.6
Steam Generator Outlet	541.3	541.3
Steam Generator		
Steam Temperature, °F	516.7(1)	507.3
Steam Pressure, psia	790(1)	727
Steam Flow, 10^6 lb/hr total	11.79(1)	11.77
Feed Temperature, °F	439.3	439.3
Moisture, % max.	0.10	0.10
Tube Plugging Level (%)	0	22(2)
Zero Load Temperature, °F	547	547

HYDRAULIC DESIGN PARAMETERS	
Mechanical Design Flow, loop gpm	101,400
Minimum Measured Flow, gpm/total	266,800

Note:
(1) For analysis purposes, maximum steam conditions are 828 psia, 522.2°F and 11.808 x 10^6 lb/hr.
(2) Steam generator tube plugging is limited to 10% due to Small Break LOCA Analysis.

Table 2.1.1-5
BVPS-2 NSSS Design (PCWG) Parameters
Current Power/OSGs (EPU Table)

(This table number is included to maintain numbering consistency with the EPU Licensing Report. The information in this table is not applicable for the RSG Licensing Report.)

2.1.2 Best Estimate NSSS Parameters (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

2.1.3 T_{avg}/Power Coastdown Parameters (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

2.2 NSSS AND AUXILIARY EQUIPMENT DESIGN TRANSIENTS (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

3 NSSS SYSTEMS

The EPU Project included analyses and evaluations for the NSSS systems at EPU conditions, including the NSSS fluid systems, NSSS control systems, and the NSSS/Balance of Plant (BOP) fluid system interfaces. The NSSS control systems and NSSS/BOP fluid system interfaces are addressed in this section.

The analyses and evaluations presented in this section support operation of BVPS-1 at EPU conditions with the Model 54F replacement steam generators (RSGs). The analyses and evaluations for EPU conditions bound and support operation at the current power level.

3.1 NSSS/BOP FLUID SYSTEM INTERFACES (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

3.2 NSSS CONTROL SYSTEMS

The EPU Project included analyses and evaluations in the following areas in order to assess the NSSS control systems performance and setpoints at EPU conditions:

1. NSSS Control Systems Stability/Operability

    - NSSS Control Systems Stability/Setpoints
    - Plant Operability Margins
    - P-9 Setpoint

2. Pressure Control Component Sizing

    - Power Operated Relief Valves
    - Pressurizer Spray Valves
    - Steam Dump Valves
    - Pressurizer Heaters

3. Cold Overpressure Mitigation System (COMS)

These analyses and evaluations are described in the following sections.

3.2.1 NSSS Control Systems Stability/Operability

The EPU Project included analyses and evaluations to assess the stability, operability and setpoints of the NSSS control systems at EPU conditions.

3.2.1.1 NSSS Control Systems Stability/Setpoints (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

3.2.1.2 Plant Operability Margins

The NSSS control systems are evaluated to show that there is adequate available plant operating margin to the various reactor trip and engineered safety features (ESF) actuation setpoints that are active during and following normal (Condition I) operating transients at EPU conditions. When there is a change in the plant operating conditions, reactor core kinetics or the control system setpoints, the effect of the changes on the plant operating margins needs to be evaluated. The EPU Project includes a full power T_{avg} window of 566.2° to 580.0°F. In addition, the OTΔT and OPΔT reactor trip equations, setpoints, and time constants were revised for the EPU Project in order to optimize operating margins at EPU conditions. For BVPS-1, the steam generator low-low level reactor trip and ESF actuation (i.e., auxiliary feedwater) setpoint and the steam generator high-high level ESF actuation (i.e., turbine trip and feedwater isolation) setpoint, along with the steam generator level control setpoint, were revised for the Model 54F RSGs. The revised reactor trip and ESF actuation setpoints, time constants and equations are shown in Section 5.10 of this report. Because of these changes, the relevant reactor trip and ESF actuation setpoints and time constants were evaluated for the EPU Project to assess the plant operating margins during and following the Condition I operating transients at EPU conditions. The purpose of this evaluation was to demonstrate that the plant operating margins are adequate at EPU conditions. The steady-state margins to the turbine runback and revised OTΔT and OPΔT reactor trip setpoints were evaluated. For BVPS-1, the operating margins to the revised steam generator low-low level trip and ESF actuation setpoint and high-high level ESF actuation setpoint were evaluated. The EPU conditions are discussed in Section 2.1.1 of this report.

BVPS-1 has a number of automatic reactor trips and automatic ESF actuations that are active during power operation. Other reactor trips are either manually actuated or are not active during power operation.

Acceptable reactor trip and ESF actuation setpoints and time constants should provide adequate margins to the nominal trip setpoints during and following the design basis normal (Condition I) operating transients. The pressurizer power operated relief valves (PORVs) should not be challenged on a step load (10%) decrease transient.

The plant operability margins evaluation showed that the margins to the revised OTΔT and OPΔT reactor trip setpoints are acceptable. For BVPS-1, the margins to the revised steam generator low-low level reactor trip and ESF actuation setpoint and the high-high level ESF actuation setpoint are acceptable. The evaluation also showed acceptable margins to the current setpoints for other relevant reactor trips (i.e., power range high flux, pressurizer low pressure, steam generator low-low level) and ESF actuations (i.e., pressurizer low pressure SI, steamline low pressure SI and MSIV closure, and steam generator high-high level turbine trip and feedwater isolation). To maintain adequate margin to the steamline low pressure SI and MSIV closure actuation setpoint, the full power steam generator outlet steam pressure must be maintained greater than or equal to 700 psia consistent with the full power operational limit

established to support steam generator structural integrity at EPU conditions. The current OTΔT and OPΔT turbine runback setpoints are also shown acceptable at EPU conditions.

The results and conclusions of the analyses and evaluations performed for plant operability margins for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

3.2.1.3 P-9 Setpoint (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

3.2.2 Pressure Control Component Sizing (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

3.2.3 Cold Overpressure Mitigation System (COMS) (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

4 NSSS COMPONENTS

The EPU Project included analyses and evaluations for the NSSS components at EPU conditions. The primary EPU-related inputs to these analyses and evaluations are the NSSS design (PCWG) parameters (Section 2.1.1). In addition to these primary inputs, the NSSS component evaluations used the existing component design basis information to assess the impact of EPU. The NSSS component evaluations were performed to confirm that the NSSS components continue to comply with applicable licensing requirements and industry codes at EPU conditions.

The following NSSS components are addressed in this section:

- Reactor Vessel
- Reactor Pressure Vessel System (i.e., Reactor Internals)
- Fuel Assemblies
- Control Rod Drive Mechanisms and Capped Latch Housings
- Reactor Coolant Loop Piping and Supports
- Reactor Coolant Pumps
- Steam Generators
- Pressurizer
- NSSS Auxiliary Equipment
- Loop Stop Isolation Valves

The analyses and evaluations presented in this section support operation of BVPS-1 at EPU conditions with the Model 54F replacement steam generators (RSGs). The analyses and evaluations for EPU conditions bound and support operation at the current power level.

4.1 REACTOR VESSEL (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

4.2 REACTOR PRESSURE VESSEL SYSTEM (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

4.3 FUEL ASSEMBLIES (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

4.4 CONTROL ROD DRIVE MECHANISMS AND CAPPED LATCH HOUSINGS (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

4.5 REACTOR COOLANT LOOP PIPING AND SUPPORTS (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

4.6 REACTOR COOLANT PUMPS AND MOTORS (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

4.7 STEAM GENERATORS

4.7.1 BVPS-1 Replacement Steam Generators

For BVPS-1, the Model 51 original steam generators (OSGs) will be replaced with Westinghouse Model 54F replacement steam generators (RSGs) prior to operation of BVPS-1 at EPU conditions (2910 MWt NSSS power). The Model 54F RSGs are being designed and analyzed for operation of BVPS-1 at 2910 MWt (970 MWt/RSG). The licensing acceptability of replacing the Model 51 OSG components with Model 54F RSG components is being evaluated under the provisions of 10 CFR 50.59. The Technical Specification changes due to design differences between the Model 51 OSG components and the Model 54F RSG components were incorporated in the EPU License Amendment Request. They have also been incorporated in the BVPS-1 RSG License Amendment Request.

The Model 54F RSG design is consistent with other advanced Westinghouse designs and is considered the replacement model that is most comparable to the Model 51 OSG in both thermal-hydraulic performance and structural design. The basic Model 54F RSG configuration has been used on several other domestic nuclear power plants (e.g., North Anna Power Station Units 1 and 2, Kewaunee Nuclear Power Plant, and Joseph M. Farley Nuclear Plant Units 1 and 2). The Model 54F RSG includes thermally treated Alloy 690 tubing, which provides enhanced resistance to stress corrosion cracking. It also incorporates a number of other design enhancements, including:

- Advanced U-bend anti-vibration bar design that provides for enhanced tube stability, and minimized potential for both wear and fatigue of tubes.
- Enhanced corrosion resistant tube support plate materials that limit the potential for crevice corrosion product buildup.
- Enhanced, structural quatrefoil tube hole support plates that improve axial flow within the tube bundle and minimize tube-to-tube support contact areas.
- Enhanced steam nozzle with integral flow restrictors to limit the steam flow area for postulated breaks in the main steam lines.
- Enlarged narrow range span (NRS) for steam generator water level control, which provides additional operating margin between the nominal level control setpoint and the low-low level trip setpoint.

- Enlarged tube bundle sized to provide a larger heat transfer area while maintaining essentially the same primary coolant flow.

The design enhancements for enlarged narrow range span and enlarged tube bundle resulted in changes to steam generator water level setpoints, including the steam generator low-low and high-high water level trip setpoints as described in Section 5.10 and the steam generator water level surveillance requirement used to confirm operability during plant shutdown, which corresponds to a level that covers the top of the tube bundle (28% NRS).

The Model 54F RSGs are being designed and analyzed for the PCWG parameters, NSSS design transients, and LOCA forces for 2910 MWt NSSS power. In addition to the NSSS power of 2910 MWt, the EPU conditions include a full power reactor vessel average temperature range of 566.2 to 580°F, a full power feedwater temperature range of 400 to 455°F, and a steam generator tube plugging range of 0 to 22%.

The thermal-hydraulic performance characteristics of the Model 54F RSGs have been used in the development of PCWG parameters and best estimate NSSS parameters for BVPS-1 at 2910 MWt NSSS power. The BVPS-1 PCWG parameters for 2910 MWt NSSS power with Model 54F RSGs are presented in Table 2.1.1-2 of this report. The Model 54F RSG thermal-hydraulic performance characteristics have also been incorporated into the other EPU analyses, as appropriate, so that these other analyses also reflect the performance of the Model 54F RSGs.

The design and analyses for the BVPS-1 Model 54F RSG components are being performed as part of the BVPS-1 RSG Project. This project includes the thermal-hydraulic analysis and ASME Code Section III structural analysis for the BVPS-1 Model 54F RSG design. A Design Report is being prepared to include the effects of the PCWG parameters, NSSS design transients, LOCA forces, and loop piping loads associated with operation of BVPS-1 at 2910 MWt NSSS power. The stress and fatigue limits defined in the 1989 Edition of the ASME Code Section III (Reference 1) is the basis of acceptability for the structural analysis. The Design Report will be completed prior to operation but after the RSGs are manufactured so that as-built dimensions can be assessed. A thermal-hydraulic design data report is also being prepared to evaluate the thermal-hydraulic performance (steam pressure, circulation ratio, moisture carryover, stability damping factor, etc.) at 2910 MWt NSSS power.

The design and analyses for the Model 54F RSGs performed for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

The following information identifies Model 54F RSG component design and analysis provisions in the areas of thermal-hydraulic performance, structural integrity, U-bend fatigue, hardware changes and additions (repair hardware), tube wear, tube plugging limit, and tube degradation. Additional information for the Model 54F RSG component is provided in WCAP-16415-NP (Reference 3).

4.7.1.1 Thermal-Hydraulic Performance

The Model 54F RSG thermal-hydraulic operating characteristics (steam pressure, circulation ratio, moisture carryover, stability damping factor) are being analyzed to demonstrate compliance with Design Specification requirements at 2910 MWt NSSS power.

4.7.1.2 Structural Integrity

The Model 54F RSGs are being designed and analyzed to meet the requirements of the 1989 Edition of the ASME Code Section III (Reference 1) at 2910 MWt NSSS power. An ASME Code Design Report is being prepared using the PCWG parameters, the NSSS design transients, and the LOCA hydraulic forces. The Model 54F RSGs are being designed and analyzed to the same primary and secondary design pressures and temperatures, and primary-to-secondary design differential pressure as the Model 51 OSGs. Secondary side steam pressure during power operation is being limited to a minimum of 700 psia in order to support the primary-to-secondary design differential pressure. The stresses and fatigue limits defined in the 1989 Edition of the ASME Code Section III (Reference 1) are being used as the basis for demonstrating structural integrity.

4.7.1.3 U-Bend Fatigue

The Model 54F RSGs include an advanced U-bend anti-vibration bar configuration that minimizes the potential for U-bend vibration, wear and fatigue. The Model 54F RSGs are being analyzed to show that tube fatigue usage factors meet the requirements of the 1989 Edition of the ASME Code Section III (Reference 1).

4.7.1.4 Hardware Changes and Additions

Hardware changes and additions (e.g., plugs) prior to service are not anticipated, but if required, would be designed and analyzed to meet applicable ASME Code requirements for the 2910 MWt NSSS power. Any hardware changes and additions that might be required during operation would be designed and analyzed to meet applicable ASME Code requirements consistent with their intended use.

4.7.1.5 Tube Wear

The Model 54F RSG tube bundle straight leg region provides for minimized potential for wear at tube support plate intersections. Flow enters the tube bundle region near the top of the tubesheet, where the tube is well supported, and is directed radially inward by the flow distribution baffle. Crossflow elsewhere in the straight leg region is minimized.

4.7.1.6 Tube Plugging Limit (Draft Regulatory Guide 1.121 Analysis)

The US NRC Draft Regulatory Guide 1.121 (Reference 2) describes an acceptable method for establishing the limiting safe condition of degradation in the tubes beyond which tubes found defective by the established in-service inspection shall be removed from service. The level of acceptable degradation is referred to as the "plugging limit." An analysis consistent with Draft Regulatory Guide 1.121 guidance has been performed for the Model 54F RSGs and has justified that the 40% through wall plugging limit is applicable.

4.7.1.7 Tube Degradation

The Model 54F RSGs are designed with Alloy 690 tubing, enhanced anti-vibration bars, corrosion resistant tube support plate materials, and structural broach hole cutouts in tube support plates to minimize the potential for tube degradation associated with operation at 2910 MWt NSSS power.

4.7.1.8 References

1. ASME Boiler and Pressure Vessel Code, Section III, "Rules for Construction of Nuclear Power Plant Components," 1989 Edition, No Addenda, The American Society of Mechanical Engineers, New York, New York, USA.

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

3. WCAP-16415-NP, "Beaver Valley Power Station Unit 1 Replacement Steam Generator Component Report," April 2005.

4.7.2 BVPS-2 Original Steam Generators (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

4.8 PRESSURIZER (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

4.9 NSSS AUXILIARY EQUIPMENT (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

4.10 LOOP STOP ISOLATION VALVES (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5 SAFETY ANALYSIS

The EPU Project included safety (accident) analyses for the Updated Final Safety Analysis Report (UFSAR) transients and accidents at EPU conditions. This section includes the evaluation of initial condition uncertainties at EPU conditions which are provided as input to the safety (accident) analyses and the development of any changes to reactor trip system (RTS)/engineered safety feature actuation system (ESFAS) setpoints as a result of the safety (accident) analyses.

In addition to initial condition uncertainties and RTS/ESFAS setpoint changes, the following safety (accident) analyses at EPU conditions are also addressed in this section:

- LOCA transients
- Non-LOCA transients
- Steam Generator Tube Rupture
- LOCA Mass and Energy Releases
- MSLB Mass and Energy Releases
- Radiological Dose Consequences

The analyses and evaluations presented in this section support operation of BVPS-1 at EPU conditions with the Model 54F replacement steam generators (RSGs). The analyses and evaluations for EPU conditions bound and support operation at the current power level.

5.1 INITIAL CONDITION UNCERTAINTIES

5.1.1 Introduction

Initial condition uncertainties are conservative steady state instrumentation measurement uncertainties that are applied to nominal parameter values in order to obtain conservative initial conditions for use in safety (accident) analyses. The initial condition uncertainties were recalculated at EPU conditions for use in the EPU Project analyses and/or evaluations to assess the acceptability of the safety analyses at EPU conditions. The initial condition uncertainties for EPU conditions were provided as input to the loss-of-coolant accident (LOCA) analysis (Section 5.2), non-LOCA analysis (Section 5.3), steam generator tube rupture (SGTR) analysis (Section 5.4), LOCA mass and energy release analysis (Section 5.5), main steamline break mass and energy release analysis (Section 5.6), and fuel thermal-hydraulic design analysis (Section 6.1).

5.1.2 Input Parameters and Assumptions

The uncertainty calculations for the Beaver Valley Power Station were performed based on the plant-specific instrumentation and plant calibration and calorimetric procedures.

5.1.3 Description of Analyses and Evaluations

The uncertainty analysis uses the Square-Root-Sum-of-the-Squares (SRSS) technique to combine the uncertainty components of an instrument channel in an appropriate combination of those components, or groups of components, which are statistically independent. Those uncertainties that are not independent

are arithmetically summed to produce groups that are independent of each other, which can then be statistically combined. The methodology used for the EPU conditions is defined in Reference 1 for BVPS-1, and is the same as was used for the NRC approved 1.4% measurement uncertainty recapture power uprate.

Initial condition uncertainties were calculated for the following six parameters that are explicitly modeled in the Beaver Valley Power Station safety analyses:

- Pressurizer Pressure Control – Automatic pressurizer pressure control system
- RCS T_{avg} Control – Automatic reactor control system
- Reactor Power – Daily calorimetric power measurement [Rated Thermal Power (RTP)] used to normalize power range instruments
- RCS Total Flow – Loop RCS flow measurements based on RCS loop flow channels normalized to a once per fuel cycle calorimetric RCS flow measurement to verify Thermal Design Flow (TDF)
- Steam Generator Water Level Control – Automatic steam generator water level control system
- Pressurizer Water Level Control – Automatic pressurizer water level control system

In order to support the start of analyses and/or evaluations for safety analyses early in the EPU Project, preliminary initial condition uncertainties for EPU were provided as input to safety analyses and/or evaluations. The initial condition uncertainties for EPU were then calculated and finalized at the end of the project at which time it was confirmed that the final values were bounded by the preliminary values. The safety analyses for EPU include the resolution of the generic steam generator water level control uncertainty issues (References 3 and 4). Although various safety analyses and/or evaluations for EPU might incorporate the preliminary initial condition uncertainties that differ from the calculated final values, the preliminary initial condition uncertainties include margin relative to the calculated final values.

5.1.4 Acceptance Criteria and Results

There are no explicit acceptance criteria for the initial condition uncertainties; however, the associated safety (accident) analyses must satisfy their applicable acceptance criteria. The initial condition uncertainties for safety analyses are documented in the UFSAR (Chapter 14 for BVPS-1). Once defined and incorporated into the safety analyses, the calculated final initial condition uncertainties must be less than or equal to the initial condition uncertainty values used in the safety analyses.

The results of the initial condition uncertainty analysis for EPU are summarized in Table 5.1-1A for BVPS-1. The results for pressurizer pressure control, RCS T_{avg} control, reactor power and RCS total flow are documented in Reference 1 for BVPS-1.

5.1.5 Conclusions

Preliminary initial condition uncertainties were determined for EPU conditions and were provided as input to the EPU Project safety analyses and/or evaluations. Final initial condition uncertainties were calculated at the end of the project at which time it was confirmed that the final values were bounded by the preliminary initial condition uncertainties. The safety analyses for EPU include the resolution of the generic steam generator water level control uncertainty issues (References 3 and 4).

The results and conclusions of the analyses and evaluations performed for initial condition uncertainties for the reactor power of 2900 MWt (2910 MWt NSSS power) bound and support operation at the current reactor power of 2689 MWt (2697 MWt NSSS power).

5.1.6 References

1. WCAP-15264, Rev. 4, "Westinghouse Revised Thermal Design Procedure Instrument Uncertainty Methodology Beaver Valley Power Station Unit 1," October 2002.

2. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

3. NSAL-03-9, "Steam Generator Water Level Uncertainties," September 22, 2003.

4. TB-04-12, "Steam Generator Level Process Pressure Evaluation," June 23, 2004.

Table 5.1-1A
BVPS-1 Summary of Initial Condition Uncertainties

Parameter	Preliminary Initial Condition Uncertainties[1]	Calculated Final Initial Condition Uncertainties[1]
Pressurizer Pressure Control	[	a,c]
RCS T_{avg} Control		
Reactor Power		
RCS Total Flow		
Steam Generator Water Level Control (@ 65% NRS)[2]		
Pressurizer Water Level Control		

Notes:

(1) A negative bias means the channel indicates lower than actual and a positive bias means the channel indicates higher than actual.

(2) The calculated final initial condition uncertainty for steam generator water level control is calculated consistent with the recommendations in Nuclear Safety Advisory Letter NSAL-03-9 (Reference 3) and Technical Bulletin TB-04-12 (Reference 4).

5.2 LOCA TRANSIENTS

The EPU Project included safety (accident) analyses for the Updated Final Safety Analysis Report (UFSAR) Loss of Coolant Accident (LOCA) transients. The following LOCA transients-related analyses at EPU conditions are addressed in this section:

- Large Break LOCA
- Small Break LOCA

5.2.1 Large Break LOCA

The Large Break Loss-of-Coolant Accident (LOCA) analysis for the EPU Project was performed using the NRC approved Large Break Best-Estimate LOCA methodology documented in WCAP-12945-P-A, Volume 1 (Revision 2), and Volumes 2 through 5 (Revision 1), "Westinghouse Code Qualification Document for Best-Estimate Loss-of-Coolant Accident Analysis," March 1998 (Westinghouse Proprietary).

The Large Break Best-Estimate LOCA analysis for the EPU Project has been submitted to the NRC for review and approval under separate License Amendment Request (LAR) No. 318 (BVPS-1).

The Large Break Best-Estimate LOCA analysis key input parameters are identified in Table 5.2.1-1A.

The results and conclusions of the Large Break Best-Estimate LOCA analysis for the reactor power of 2900 MWt (2910 MWt NSSS power) bound and support operation at the current reactor power of 2689 MWt (2697 MWt NSSS power).

Table 5.2.1-1A
BVPS-1 Major Plant Parameters
Used in the Best-Estimate Large Break LOCA Analysis

Parameter	Value	Intended Location
Plant Physical Description		
Steam Generator Tube Plugging	≤ 22 %	UFSAR Section 14.3
Plant Initial Operating Conditions		
Reactor Power	≤ 100.6% of 2900 MWt including 0.6% Calorimetric Uncertainty	UFSAR Section 14.3
Peaking Factor	FQ=2.52, FΔH=1.75	COLR
Fluids Conditions		
RCS Average Temperature (T_{avg})	566.2 ± 4.1°F ≤ T_{avg} ≤ 580.0 ± 4.1°F	UFSAR Section 14.3
Pressurizer Pressure	2200-2300 psia	UFSAR Section 14.3
Reactor Coolant Flow	≥ 87,200 gpm/loop	UFSAR Section 14.3
Accumulator Temperature	70-105°F	UFSAR Section 14.3
Accumulator Pressure	575-716 psia	UFSAR Section 14.3
Accumulator Water Volume	893-1022 ft3	UFSAR Section 14.3
Accident Boundary Conditions		
Single Failure Assumptions	1 Train of ECCS Pumps	UFSAR Section 14.3
Safety Injection Flow	Table 5.2.1-2A	UFSAR Section 14.3
Safety Injection Temperature	45-105°F	UFSAR Section 14.3
Safety Injection Initiation Delay Time	≤ 17 sec Off-Site Power Available ≤ 27 sec Loss of Off-Site Power (LOOP)	UFSAR Section 14.3

Table 5.2.1-2A
BVPS-1 Best-Estimate Large Break LOCA Total Minimum Injected SI Flow
(HHSI and LHSI from 2 Intact Loops)

RCS Pressure (psig)	Flow Rate (gpm)
0	2433.0
10	2272.1
20	2106.2
50	1569.1
100	338.1
105	278.4
150	270.4
200	261.4
400	219.2
600	173.4

5.2.2 Small Break LOCA

5.2.2.1 Introduction

This section contains information regarding the Small Break Loss-of-Coolant Accident (SBLOCA) analyses performed in support of the EPU for BVPS-1 (with Model 54F replacement steam generators) at the NSSS power level of 2910 MWt (2900 MWt reactor power). The purpose of analyzing the Small Break LOCA is to demonstrate conformance with the 10 CFR 50.46 (Reference 1) requirements for the conditions associated with the EPU. Important input assumptions, as well as analytical models and analysis methodology for the Small Break LOCA are contained in subsequent sections. Analysis results are provided in the form of tables and figures, as well as a more detailed description of the limiting transient. The analysis has shown that no design or regulatory limit related to the Small Break LOCA would be exceeded due to the EPU power and associated plant parameters.

5.2.2.2 Input Parameters and Assumptions

The important plant conditions and features for BVPS-1 are listed in Table 5.2.2-1A. Several additional considerations that are not identified in Table 5.2.2-1A are discussed below.

Figure 5.2.2-1 depicts the hot rod axial power shape modeled in the Small Break LOCA analyses. This shape was chosen because it represents a distribution with power concentrated in the upper regions of the core (the axial offset is +13%). Such a distribution is limiting for Small Break LOCA since it minimizes coolant swell while maximizing vapor superheating and fuel rod heat generation at the uncovered elevations. The chosen power shape has been conservatively scaled to a standard 2-line segment K(Z) envelope for BVPS-1 based on the peaking factors shown in Table 5.2.2-1A.

Figure 5.2.2-2 provides the SI flow versus pressure curves modeled in the Small Break LOCA analyses. The flow from one High Head Safety Injection (HHSI) pump was used in the analyses.

5.2.2.3 Description of Analyses and Evaluations

Analytical Model

The requirements for an acceptable ECCS evaluation model are presented in Appendix K of 10 CFR 50. For LOCAs due to Small Breaks, less than 1 square foot in area, the Westinghouse NOTRUMP Small Break LOCA Emergency Core Cooling System (ECCS) Evaluation Model (References 2, 3, and 4) is used. The Westinghouse NOTRUMP Small Break LOCA ECCS Evaluation Model was developed to determine the RCS response to design basis Small Break LOCAs, and to address NRC concerns expressed in NUREG-0611 (Reference 5).

The Westinghouse Small Break LOCA ECCS Evaluation Model consists of the NOTRUMP and LOCTA-IV computer codes. The NOTRUMP code is employed to calculate the transient depressurization of the Reactor Coolant System (RCS), as well as to describe the mass and energy release of the fluid flow through the break. Among the features of the NOTRUMP code are: calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flooding limitations, mixture level tracking logic in multiple-stacked fluid nodes,

regime-dependent drift flux calculations in multiple-stacked fluid nodes and regime-dependent heat transfer correlations. These features provide NOTRUMP with the capability to accurately calculate the mass and energy distribution throughout the RCS during the course of a Small Break LOCA.

The RCS model is nodalized into volumes interconnected by flow paths. The broken loop is modeled explicitly, while the intact loops are lumped together into a second loop. Transient behavior of the system is determined from the governing conservation equations of mass, energy, and momentum. The multi-node capability of the program enables explicit, detailed spatial representation of various system components which, among other capabilities, enables a calculation of the behavior of the loop seal during a Small Break LOCA. The reactor core is represented as heated control volumes with associated phase separation models to permit transient mixture height calculations.

Fuel cladding thermal analyses are performed with a version of the LOCTA-IV code (Reference 2) using the NOTRUMP calculated core pressure, fuel rod power history, uncovered core steam flow and mixture heights as boundary conditions. The LOCTA-IV code models the hot rod and the average hot assembly rod, assuming a conservative power distribution that is skewed to the top of the core. Figure 5.2.2-3 illustrates the code interface for the Small Break Model.

Analysis

The EPU Small Break LOCA analyses considered three different break cases for BVPS-1 as indicated by the results in Table 5.2.2-3A. For BVPS-1, a break spectrum of 2-, 3-, and 4-inch breaks was considered and the 3-inch break was found to be limiting. The most limiting single active failure used for a Small Break LOCA is that of an emergency power train failure which results in the loss of one complete train of ECCS components. In addition, a Loss-of-Offsite Power (LOOP) is postulated to occur coincident with reactor trip. This means that credit may be taken for at most one high head safety injection (HHSI) pump. In the analyses for BVPS-1, one HHSI pump is modeled. The Small Break LOCA analysis performed for BVPS-1 models the ECCS flow as being delivered to both the intact and broken loops at the RCS backpressure for breaks smaller than the cold leg HHSI nozzle (2-, 3-, and 4-inch breaks for BVPS-1). These broken and intact loop SI flows are illustrated in Figure 5.2.2-2. The LOOP and the failure of a diesel generator to start as the limiting single failure for Small Break LOCA is part of the NRC approved methodology and does not change as a result of the EPU conditions. The single failure assumption is extremely limiting due to the fact that one train of SI, one motor driven auxiliary feedwater (AFW) pump, and power to the reactor coolant pumps (RCPs) are all modeled to be lost. Any other active single failure would not result in a more limiting scenario since increased SI flow would improve the overall transient results.

Prior to break initiation, the plant is in a full power (100.6%) equilibrium condition, i.e., the heat generated in the core is being removed via the secondary system. Other initial plant conditions used in the analysis are given in Table 5.2.2-1A. Subsequent to the break opening, a period of reactor coolant system blowdown ensues in which the heat from fission product decay, the hot reactor internals, and the reactor vessel continues to be transferred to the RCS fluid. The heat transfer between the RCS and the secondary system may be in either direction and is a function of the relative temperatures of the primary and secondary conditions. In the case of continuous heat addition to the secondary during a period of quasi-equilibrium, an increase in the secondary system pressure results in steam relief via the steam generator safety valves.

When a Small Break LOCA occurs, depressurization of the RCS causes fluid to flow into the loops from the pressurizer resulting in a pressure and level decrease in the pressurizer. The reactor trip signal subsequently occurs when the pressurizer low-pressure reactor trip setpoint, conservatively modeled as 1935 psia, is reached. LOOP is postulated to occur coincident with reactor trip. A safety injection signal is generated when the pressurizer low-pressure safety injection setpoint, conservatively modeled as 1745 psia for BVPS-1, is reached. Safety injection flow is delayed 27 seconds after the occurrence of the low-pressure condition. This delay accounts for signal processing, diesel generator start up and emergency power bus loading consistent with the loss-of-offsite power coincident with reactor trip, as well as the pump acceleration and valve delays.

The following countermeasures limit the consequences of the accident in two ways:

1. Reactor trip and borated water injection supplement void formation in causing a rapid reduction of nuclear power to a residual level corresponding to the delayed fission and fission product decay. No credit is taken in the Small Break LOCA analysis for the boron content of the injection water. In addition, credit is taken in the Small Break LOCA analysis for the insertion of Rod Cluster Control Assemblies (RCCAs) subsequent to the reactor trip signal, considering the most reactive RCCA is stuck in the full out position. A rod drop time of 2.7 seconds was used while also considering an additional 2 seconds for the signal processing delay time. Therefore, a total delay time of 4.7 seconds from the time of reactor trip signal to full rod insertion was used in the Small Break LOCA analysis.

2. Injection of borated water provides sufficient flooding of the core to prevent excessive cladding temperatures.

During the earlier part of the Small Break transient (prior to the postulated loss-of-offsite power coincident with reactor trip), the loss of flow through the break is not sufficient to overcome the positive core flow maintained by the reactor coolant pumps. During this period, upward flow through the core is maintained. However, following the reactor coolant pump trip (due to a LOOP) and subsequent pump coastdown, a period of core uncovery occurs. Ultimately, the Small Break transient analysis is terminated when the top of the core is recovered or the core mixing level is increasing, and ECCS flow provided to the RCS exceeds the break flow rate.

The core heat transfer mechanisms associated with the Small Break transient include the break itself, the injected ECCS water, and the heat transferred from the RCS to the steam generator secondary side. Main Feedwater (MFW) is conservatively isolated in 10 seconds for BVPS-1 (consisting of a 3 second signal delay time and a 7 second main feedwater isolation valve stroke time) following the generation of the pressurizer low-pressure SI signal. Additional makeup water is also provided to the secondary using the auxiliary feedwater (AFW) system. An AFW actuation signal is derived from the pressurizer low-pressure SI signal, resulting in the delivery of AFW system flow 60 seconds after the generation of the SI signal. The heat transferred to the secondary side of the steam generator aids in the reduction of the RCS pressure.

Should the RCS depressurize to approximately 575 psia (accumulator minimum pressure), the cold leg accumulators begin to inject borated water into the reactor coolant loops.

5.2.2.4 Acceptance Criteria and Results

The acceptance criteria for the LOCA are described in 10 CFR 50.46 (Reference 1) as follows:

1. The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

2. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

5. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

Criteria 1 through 3 are explicitly covered by the Small Break LOCA analysis at EPU conditions.

For criterion 4, the appropriate core geometry was modeled in the analysis. The results based on this geometry satisfy the Peak Clad Temperature (PCT) criterion of 10 CFR 50.46 and consequently, demonstrate that the core remains amenable to cooling.

For criterion 5, Long-Term Core Cooling (LTCC) considerations are not directly applicable to the Small Break LOCA transient analysis addressed in this section, but are assessed as part of the evaluation of ECCS performance.

The acceptance criteria were established to provide a significant margin in ECCS performance following a LOCA.

In order to determine the conditions that produced the most limiting Small Break LOCA case (as determined by the highest calculated peak cladding temperature), three break cases were examined for BVPS-1. These cases were investigated to capture the most severe postulated Small Break LOCA event. The following discussions provide insight into the analyzed conditions.

Limiting Temperature Conditions

The RCS temperature analyzed was based on a nominal vessel average temperature of 580.0°F. However, the analysis is applicable over the range of 566.2 – 580.0°F. The analysis supports a ±4°F T_{avg} uncertainty. The analysis showed that the 3-inch break case is limiting for BVPS-1. The limiting case transient is discussed below.

Limiting Break Case

The results of Reference 6 demonstrate that the cold leg break location is limiting with respect to postulated cold leg, hot leg and pump suction leg break locations. The PCT results are shown in Table 5.2.2-3A. Inherent in the Small Break analysis are several input parameters (see Section 5.2.2.2 and Table 5.2.2-1A), while Table 5.2.2-4A provide the key transient event times.

For the EPU Small Break LOCA analysis, the limiting case for BVPS-1 was the 3-inch break case. A summary of the transient response for the limiting case is shown in Figures 5.2.2-4A through Figure 5.2.2-14A. These figures present the response of the following parameters.

- RCS Pressure
- Core Mixture Level
- Core Exit Vapor Temperature
- Broken Loop and Intact Loop Secondary Pressure
- Break Vapor Flow Rate
- Break Liquid Flow Rate
- Broken Loop and Intact Loop Accumulator Flow Rate
- Broken Loop and Intact Loop Pumped Safety Injection Flow Rate
- Peak Clad Temperature
- Hot Spot Fluid Temperature
- Rod Film Heat Transfer Coefficient

Upon initiation of the limiting 3-inch break for BVPS-1, there is an initial rapid depressurization of the RCS followed by an intermediate equilibrium at approximately 1150 psia (see Figure 5.2.2-4A). The limiting 3-inch break depressurizes to the accumulator injection setpoint of 575 psia at approximately 1355 seconds for BVPS-1 (see Figure 5.2.2-10A). During the initial period of the Small Break transient, the effect of the break flow rate is not sufficient to overcome the flow rate maintained by the reactor coolant pumps as they coast down. As such, normal upward flow is maintained through the core and core heat is adequately removed. Following reactor trip, the removal of the heat generated as a result of fission products decay is accomplished via a two-phase mixture level covering the core. The core mixture level and peak clad temperature transient plots for the limiting break calculations are illustrated in Figures 5.2.2-5A and 5.2.2-12A, respectively. These figures show that the peak clad temperature occurs near the time when the core is most deeply uncovered and the top of the core is being cooled by steam. This time is characterized by the highest vapor superheating above the mixture level (refer to Figure 5.2.2-6A). For BVPS-1 the limiting time-in-life was determined to be 8500 MWD/MTU. A comparison of the flow provided by the safety injection system to the intact and broken loops can be found in Figure 5.2.2-11A. The cold leg break vapor and liquid mass flow rates are provided in Figures 5.2.2-8A and 5.2.2-9A, respectively. Figures 5.2.2-13A and 5.2.2-14A provide additional information on the fluid temperature at the hot spot and hot rod surface heat transfer coefficient at the hot spot, respectively. Figure 5.2.2-7A depicts the secondary side pressure for both the intact and broken loops for the limiting break case.

Additional Break Cases

Studies documented in Reference 6 have determined that the limiting Small Break transient occurs for breaks of less than 10-inches in diameter in the cold leg. To demonstrate that the 3-inch diameter break for BVPS-1 was the most limiting, calculations were also performed with break equivalent diameters of 2- and 4-inches for BVPS-1. For BVPS-1, the limiting PCT is captured by the 2-, 3-, and 4-inch break spectrum. The results of these break spectrum cases are given in Table 5.2.2-3A. Figures 5.2.2-15A through 5.2.2-17A and Figures 5.2.2-18 through 5.2.2-20 address the non-limiting cases (2- and 4-inch) analyzed for BVPS-1. The plots for each of the additional non-limiting break cases include:

1. RCS Pressure
2. Core Mixture Level
3. Peak Clad Temperature

For BVPS-1, the PCTs for each of the additional breaks considered are shown in Table 5.2.2-3A, these PCTs are less than the limiting 3-inch break case.

Transient Termination

The 10 CFR 50.46 criteria continue to be satisfied beyond the end of the calculated transient due to the following conditions:

1. The RCS pressure is gradually decreasing.
2. The net mass inventory is increasing.
3. The core mixture level is recovered, or recovering due to increasing mass inventory.
4. As the RCS inventory continues to gradually increase, the core mixture level will continue to increase and the fuel cladding temperatures will continue to decline indicating that the temperature excursion is terminated.

ZIRLO/Zirc-4 Cladding

At the time at which this analysis is implemented, no new Zirc-4 fuel is expected to be inserted into the core. All of the Zirc-4 fuel will be burned for at least one cycle, and ZIRLO™ fuel will be implemented at non-EPU conditions at least one reload cycle before the EPU is implemented. Therefore, the ZIRLO™ fuel is considered limiting with a PCT of 1739°F at 8500 MWD/MTU burnup for BVPS-1. The fuel temperatures/pressures used in these calculations were based on NRC approved fuel performance code PAD 4.0 (Reference 7) which addresses all the helium release related issues. This analysis has been performed using the most limiting temperature/pressure as calculated for 17×17 non-IFBA RFA fuel. The non-IFBA fuel bounds IFBA fuel for Small Break LOCA analyses.

5.2.2.5 Conclusions

The Small Break LOCA analyses considered a break spectrum of 2-, 3-, and 4-inch diameters for BVPS-1. For BVPS-1, a peak cladding temperature of 1739°F was calculated at the limiting time-in-life of 8500 MWD/MTU. The BVPS-1 limiting PCT occurred for the 3-inch break case. The analyses presented in this section show that the accumulator and safety injection subsystems of the Emergency

Core Cooling System, together with the heat removal capability of the steam generator, provide sufficient core heat removal capability to maintain the calculated peak cladding temperatures for Small Break LOCA below the required limit of 10 CFR 50.46. Furthermore, the analyses show that the local cladding oxidation and core wide average oxidation are less than the 10 CFR 50.46 (Reference 1) limits.

The results and conclusions of the analyses performed for Small Break LOCA for the reactor power of 2900 MWt (2910 MWt NSSS power) bound and support operation at the current reactor power of 2689 MWt (2697 MWt NSSS power).

5.2.2.6 References

1. "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors," 10 CFR 50.46 and Appendix K of 10 CFR 50, Federal Register, Volume 39, Number 3, January 1974, as amended in Federal Register, Volume 53, September 1988.

2. Meyer, P. E., "NOTRUMP – A Nodal Transient Small Break and General Network Code," WCAP-10079-P-A, (proprietary) and WCAP-10080-NP-A (non-proprietary), August 1985.

3. Lee, N. et al., "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," WCAP-10054-P-A (proprietary) and WCAP-10081-NP-A (non-proprietary), August 1985.

4. Thompson, C. D. et al., "Addendum to the Westinghouse ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," WCAP-10054-P-A, Addendum 2, Rev. 1, July 1997.

5. "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse – Designed Operating Plant," NUREG-0611, January 1980.

6. Rupprecht, S. D. et al., "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code," WCAP-11145-P-A (proprietary), October 1986.

7. Slagle, W. H., (ed.) et al., "Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)," WCAP-15063-P-A, Revision 1, July 2000.

Table 5.2.2-1A
BVPS-1 Input Parameters Used in the Small Break LOCA Analysis

Input Parameter	Value
Core Rated Thermal Power-100%	2900
Calorimetric Uncertainty, %	0.6
Fuel Type	17×17 Robust Fuel Assembly (RFA)
Total Core Peaking Factor, F_Q	2.40
Hot Channel Enthalpy Rise Factor, $F_{\Delta H}$	1.62
Hot Assembly Average Power Factor, P_{HA}	1.42
Maximum Axial Offset, %	+13
Initial RCS Loop Flow, gpm/loop	82,840
Initial Vessel T_{avg}, °F	Max: 580.0 Min: 566.2
Initial Pressurizer Pressure (plus uncertainties), psia	2300
Reactor Coolant Pump Type	Model 93A with Weir
Pressurizer Low-Pressure Reactor Trip Setpoint, psia	1935
Reactor Trip Signal Delay Time, seconds	2.0
Rod Drop Delay Time, seconds	2.7
Auxiliary Feedwater Temperature (Maximum), °F	120
Number of AFW Pumps Available Following a LOOP	1 Motor Driven
AFW Flow (Minimum) to all 3 Steam Generators, gpm	294 (98 gpm/SG * 3) at 1107 psig
AFW Flow Delay Time (Maximum), seconds	60
AFW Actuation Signal	Pressurizer Low-Pressure Safety Injection
Steam Generator Type	Model 54F
Maximum AFW Piping Purge Volume, ft^3	168
Steam Generator Tube Plugging (Maximum), %	10
Maximum MFW Isolation Signal Delay Time, seconds	3
MFW Control Valve Isolation Ramp Time, seconds	7
MFW Isolation Signal	Pressurizer Low-Pressure Safety Injection
Isolation of Steam Line Signal	Pressurizer Low-Pressure Reactor Trip/LOOP
Steam Generator Secondary Water Mass, lbm/SG	99,930
Containment Spray Flowrate for 2 Pumps, gpm	4983 (plus 981 gpm to account for flow to the sump)
RWST Deliverable Volume (Minimum), gallons	317,000

Table 5.2.2-1A (continued) BVPS-1 Input Parameters Used in the Small Break LOCA Analysis	
Input Parameter	**Value**
SI Temp at Cold Leg Recirculation Time (Maximum), °F	190
ECCS Configuration	1 HHSI pump, faulted line injects to RCS pressure
ECCS Water Temperature (Maximum), °F	65
Pressurizer Low-Pressure Safety Injection Setpoint, psia	1745
SI Flow Delay Time, seconds	27
ECCS Flow vs. Pressure	See Table 5.2.2-2
Initial Accumulator Water/Gas Temperature, °F	105
Initial Nominal Accumulator Water Volume, ft^3	957
Minimum Accumulator Pressure, psia	575

Table 5.2.2-2
Safety Injection Flows Used in the Small Break LOCA Analysis
(1 HHSI pump, faulted loop injects to RCS pressure – 2-, 3-, and 4-inch breaks for BVPS-1)

RCS Pressure (psia)	Intact Loop (lbm/sec)	Broken Loop (lbm/sec)
314.7	37.59	20.28
414.7	36.63	19.79
514.7	35.56	19.17
614.7	34.45	18.61
714.7	33.42	18.06
814.7	32.34	17.50
914.7	31.25	16.88
1014.7	30.14	16.25
1114.7	29.03	15.70
1214.7	27.92	15.07
1314.7	26.67	14.45
1414.7	25.28	13.61
1514.7	23.85	12.92
1614.7	22.43	12.08
1714.7	20.97	11.39
1814.7	19.50	10.56

Table 5.2.2-3A BVPS-1 SBLOCTA Results				
	2-inch BOL	3-inch 8,500 MWD/MTU	4-inch BOL	3-inch Annular Pellet 8,500 MWD/MTU
PCT (°F)	1703	1737	1203	1739
PCT Time (s)	3158	1734	917	1724
PCT Elevation (ft)	12.00	12.00	11.25	12.00
Burst Time (s)	N/A	1732	N/A	1722
Burst Elevation (ft)	N/A	12.00	N/A	12.00
Max. Local ZrO_2 (%)	3.04	6.32	0.08	6.37
Max. Local ZrO_2 Elev. (ft)	11.75	12.00	11.25	12.00
Core-Wide Avg. ZrO_2 (%)	0.40	0.63	0.01	0.63

Table 5.2.2-4A
BVPS-1 NOTRUMP Results

Event Time (sec)	2-inch	3-inch	4-inch
Break Initiation	0	0	0
Reactor Trip Signal	28.9	12.3	7.3
S-Signal	42.3	20.8	14.4
SI Flow Delivered	69.9	47.8	41.4
Loop Seal Clearing(1)	925	420	250
Core Uncovery	1020	862	236
Accumulator Injection	N/A	1355	766
RWST Volume Delivered	3025	3003	2992
PCT Time	3158	1735	917
Core Recovery(2)	>TMAX	>TMAX	>TMAX

Notes:

(1) Loop seal clearing is defined as break vapor flow > 1 lb/s.

(2) For the cases where core recovery is > TMAX, basis for transient termination can be concluded based on the following: (1) The RCS system pressure is decreasing which will increase SI flow, (2) Total RCS system mass is increasing due to SI flow exceeding break flow, and (3) Core mixture level has begun to increase and is expected to continue for the remainder of the accident.

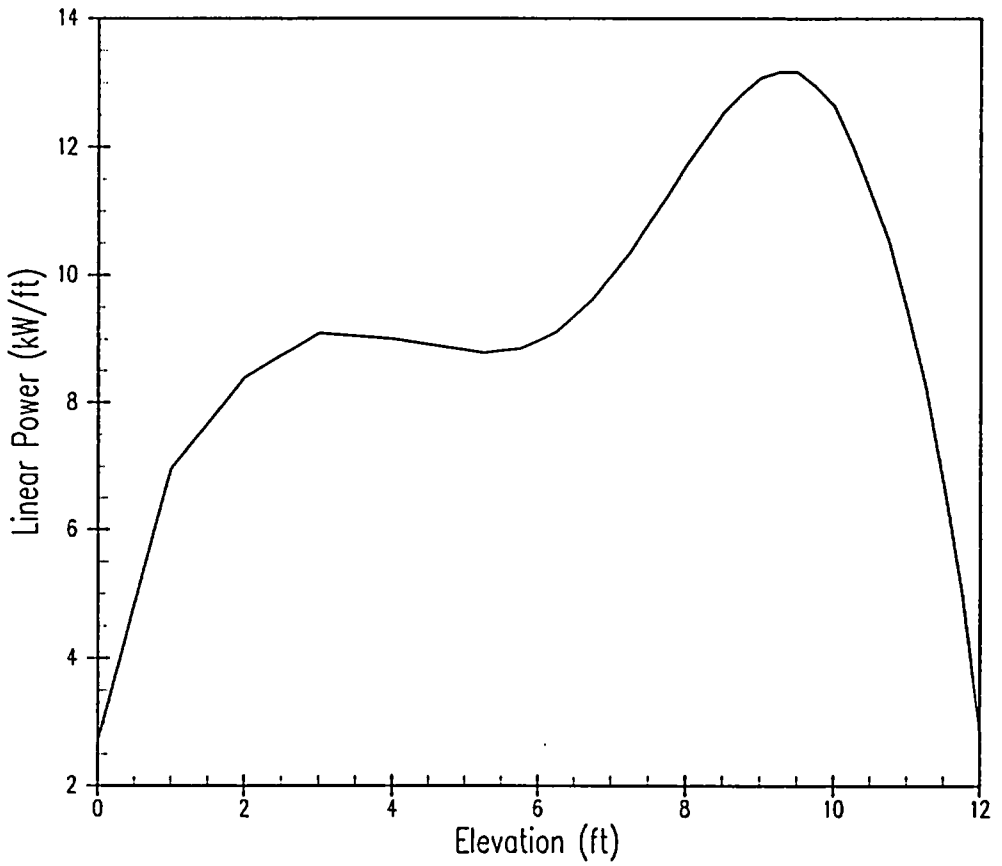


Figure 5.2.2-1
Small Break Hot Rod Power Shape

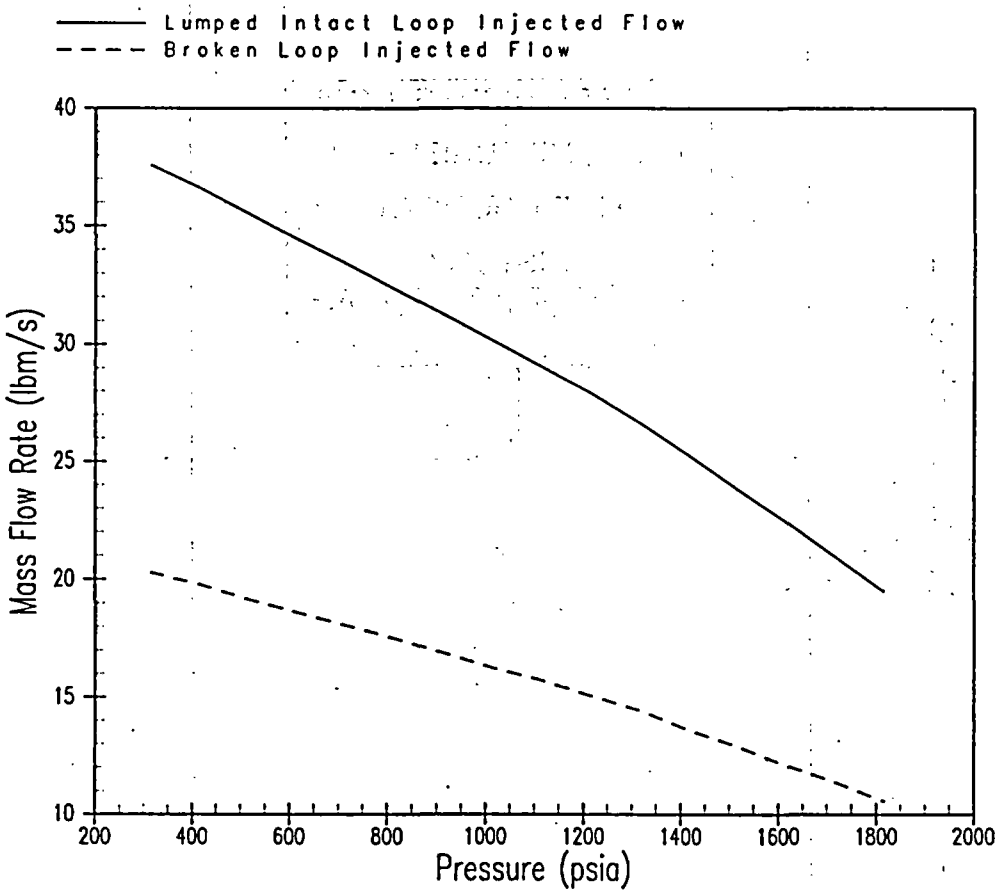


Figure 5.2.2-2
Small Break LOCA Safety Injection Flows
(1 HHSI pump, faulted loop injects to RCS pressure – 2-, 3-, and 4-inch breaks for BVPS-1)

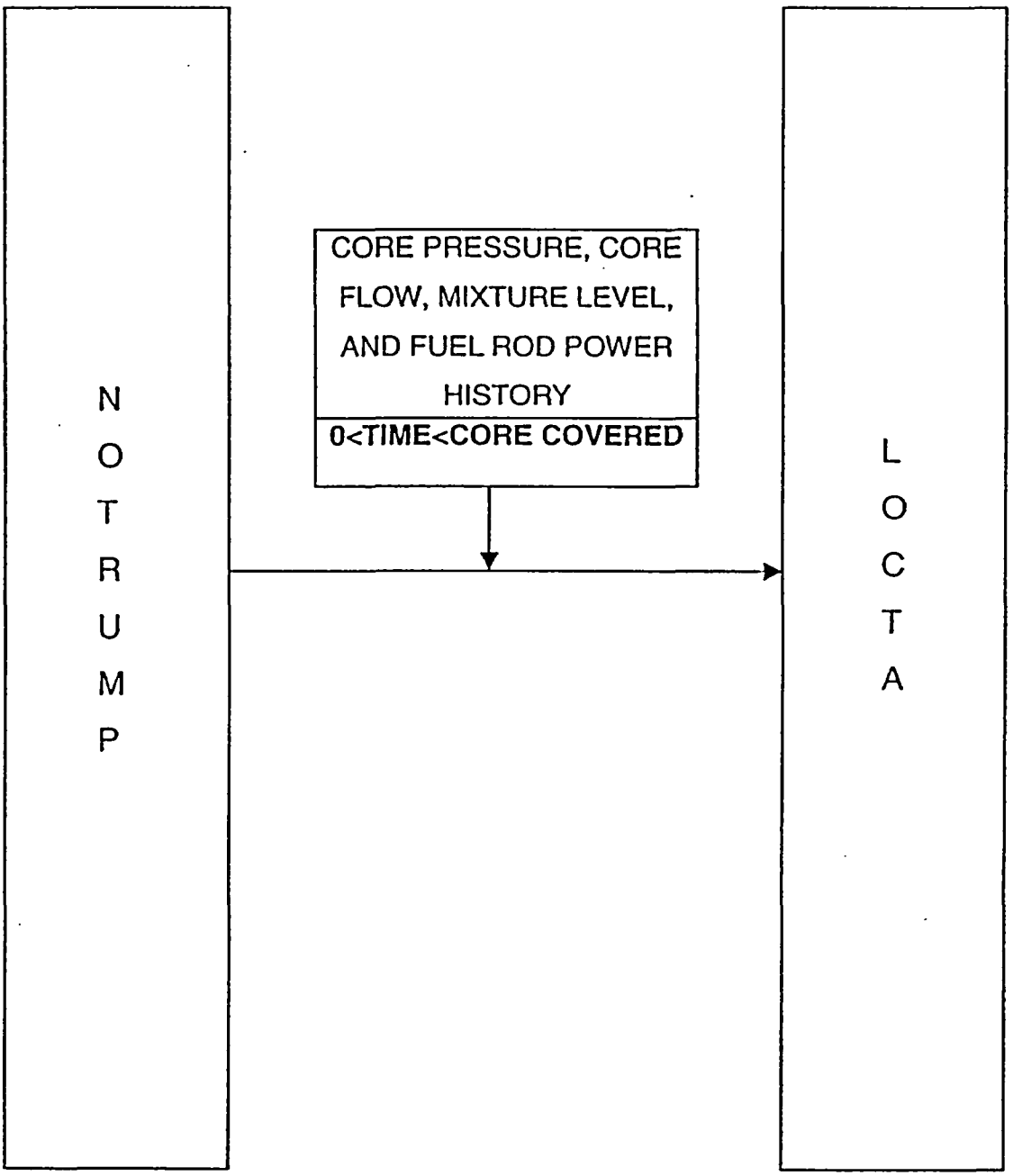


Figure 5.2.2-3
Code Interface Description
for Small Break Model

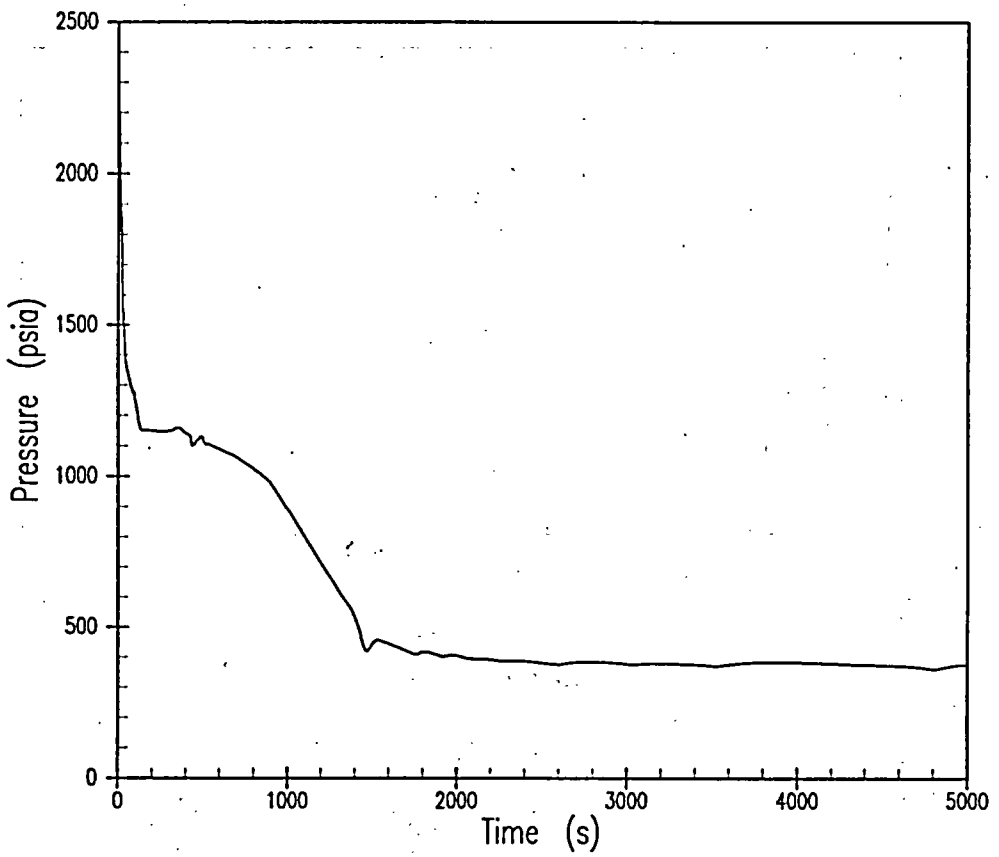


Figure 5.2.2-4A
BVPS-1 3-inch Break
RCS Pressure

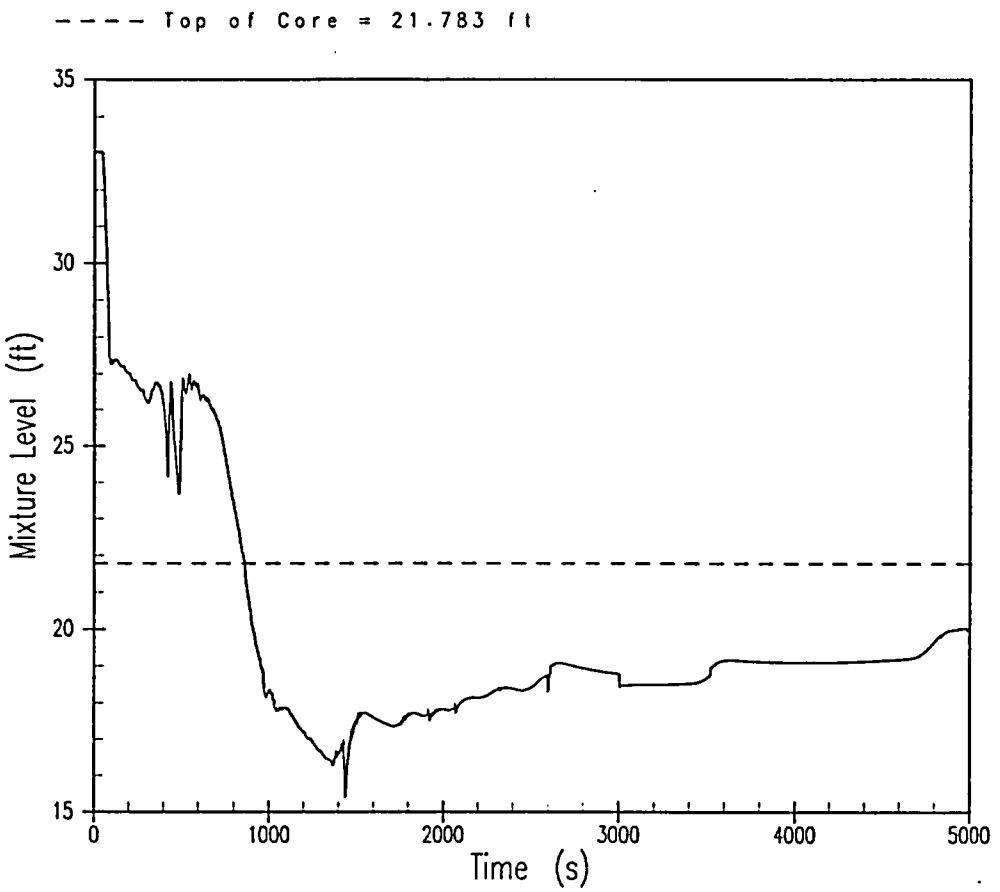


Figure 5.2.2-5A
BVPS-1 3-inch Break
Core Mixture Level

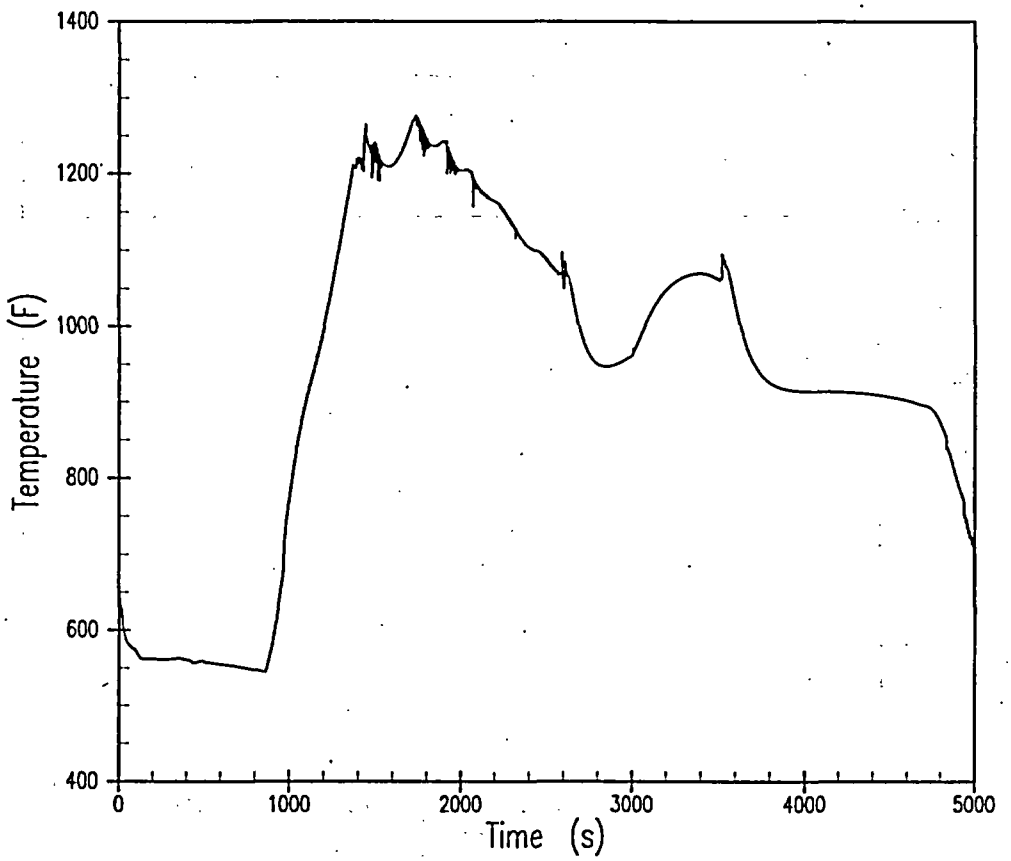


Figure 5.2.2-6A
BVPS-1 3-inch Break
Core Exit Vapor Temperature

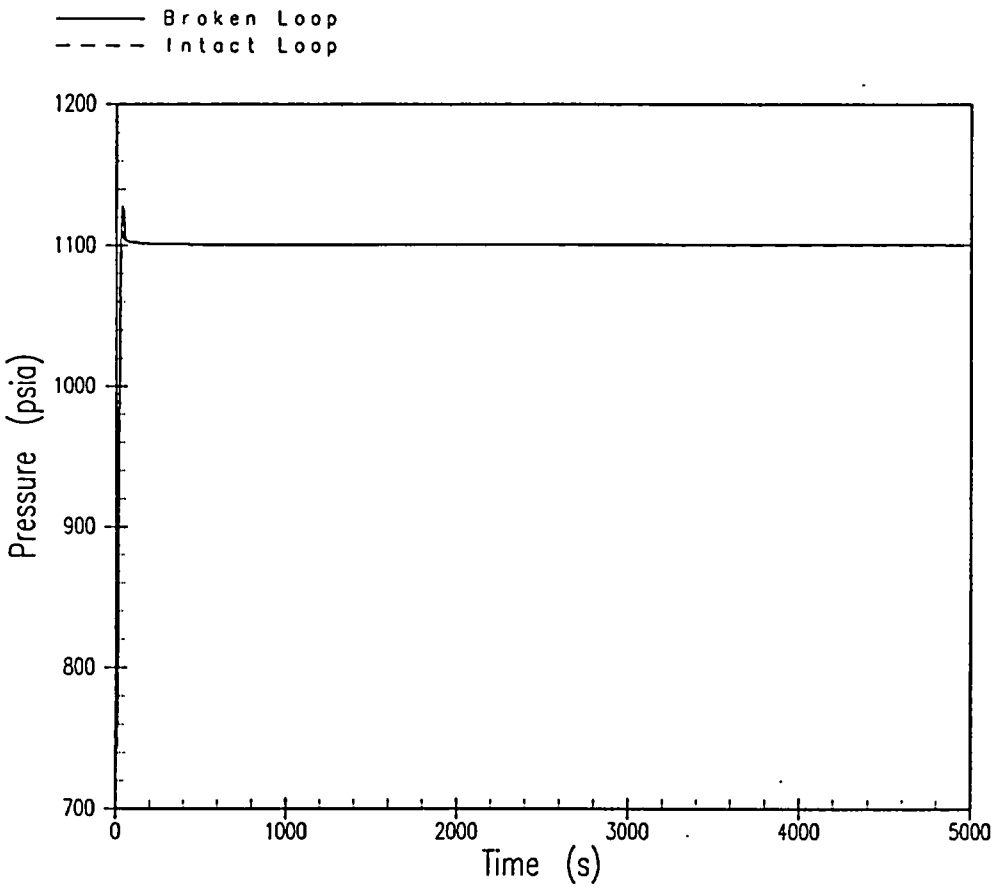


Figure 5.2.2-7A
BVPS-1 3-inch Break
Broken Loop and Intact Loop Secondary Pressure

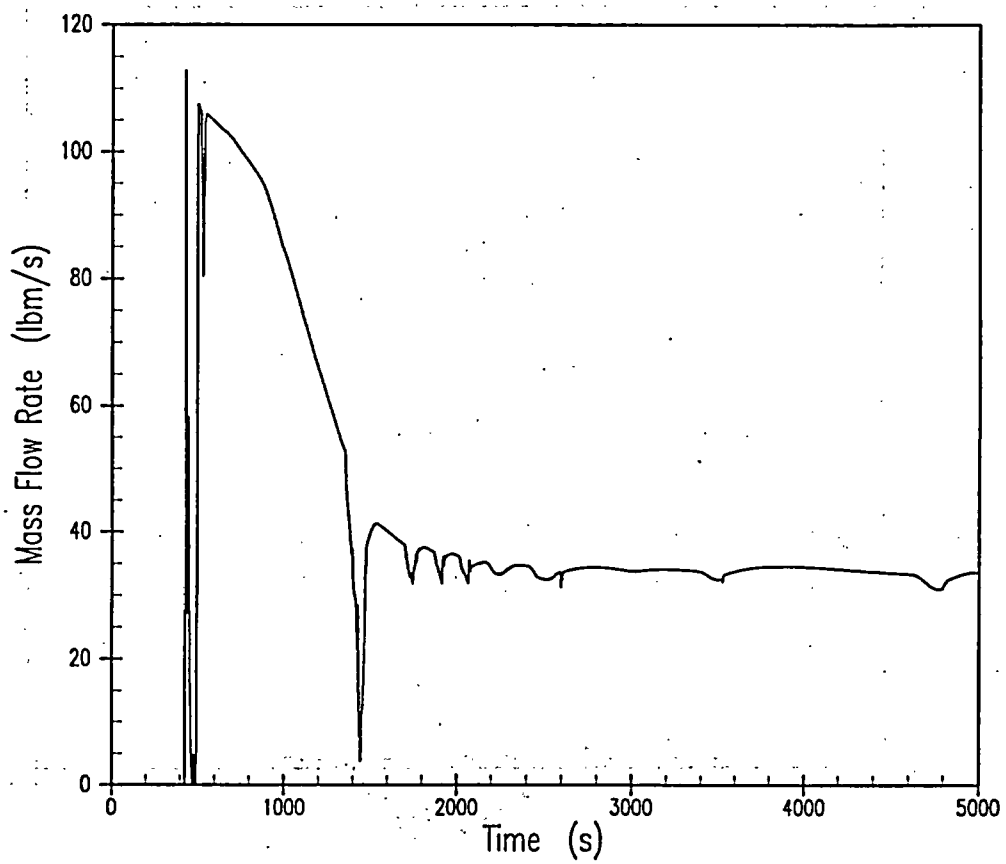


Figure 5.2.2-8A
BVPS-1 3-inch Break
Break Vapor Flow Rate

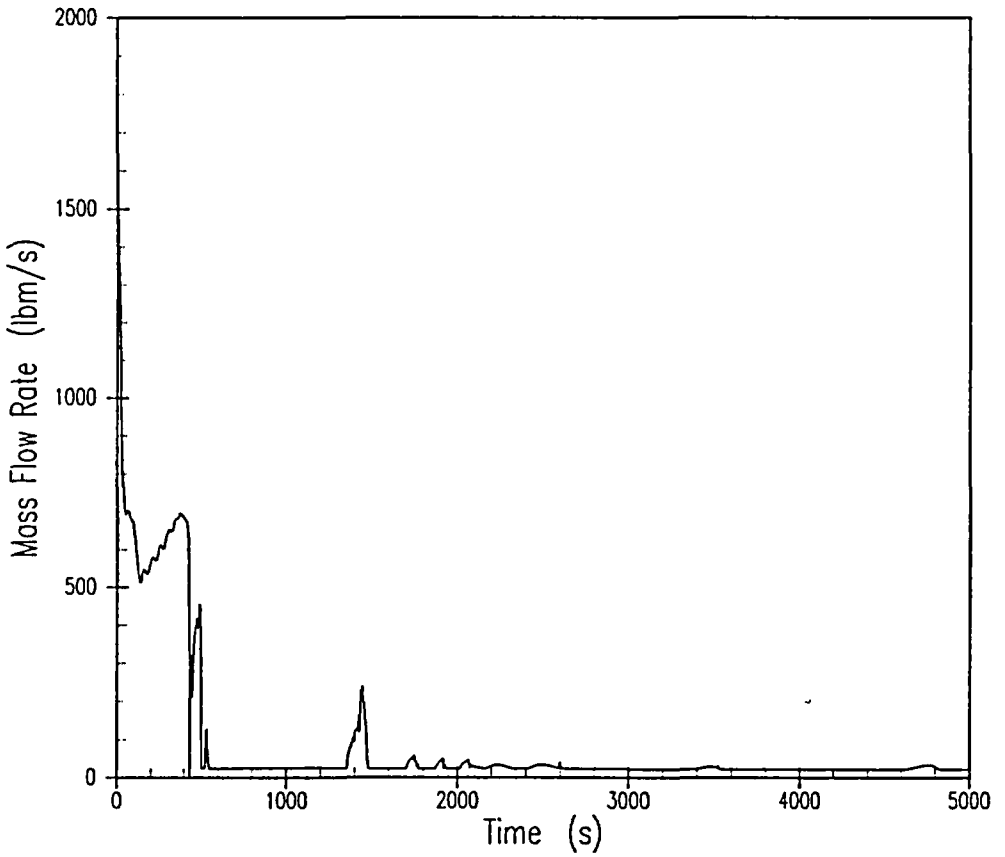


Figure 5.2.2-9A
BVPS-1 3-inch Break
Break Liquid Flow Rate

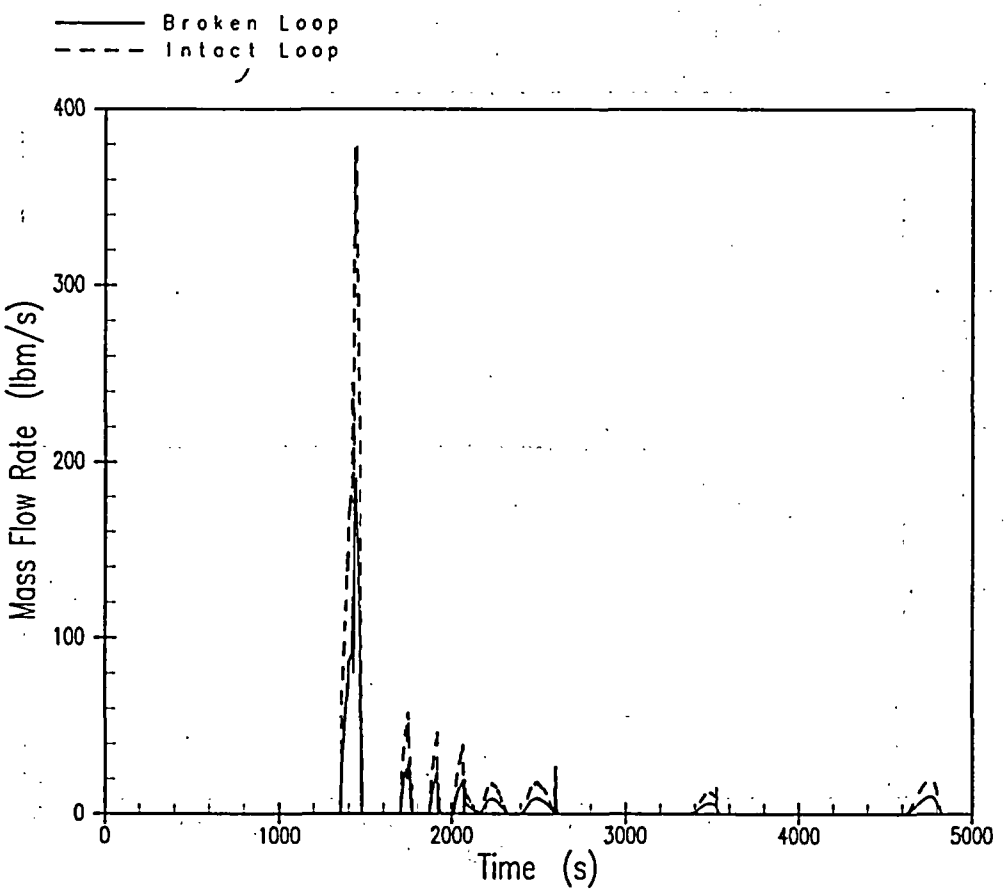


Figure 5.2.2-10A
BVPS-1 3-inch Break
Broken Loop and Intact Loop Accumulator Flow Rate

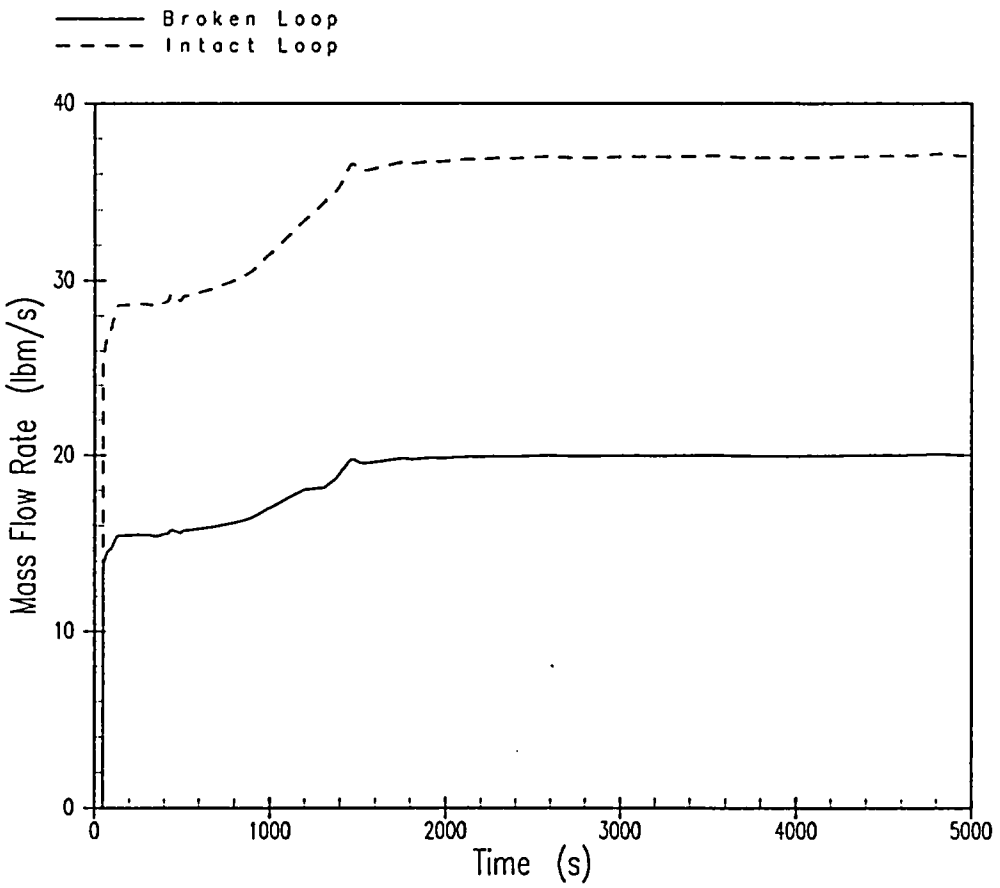


Figure 5.2.2-11A
BVPS-1 3-inch Break
Broken Loop and Intact Loop Pumped Safety Injection Flow Rate

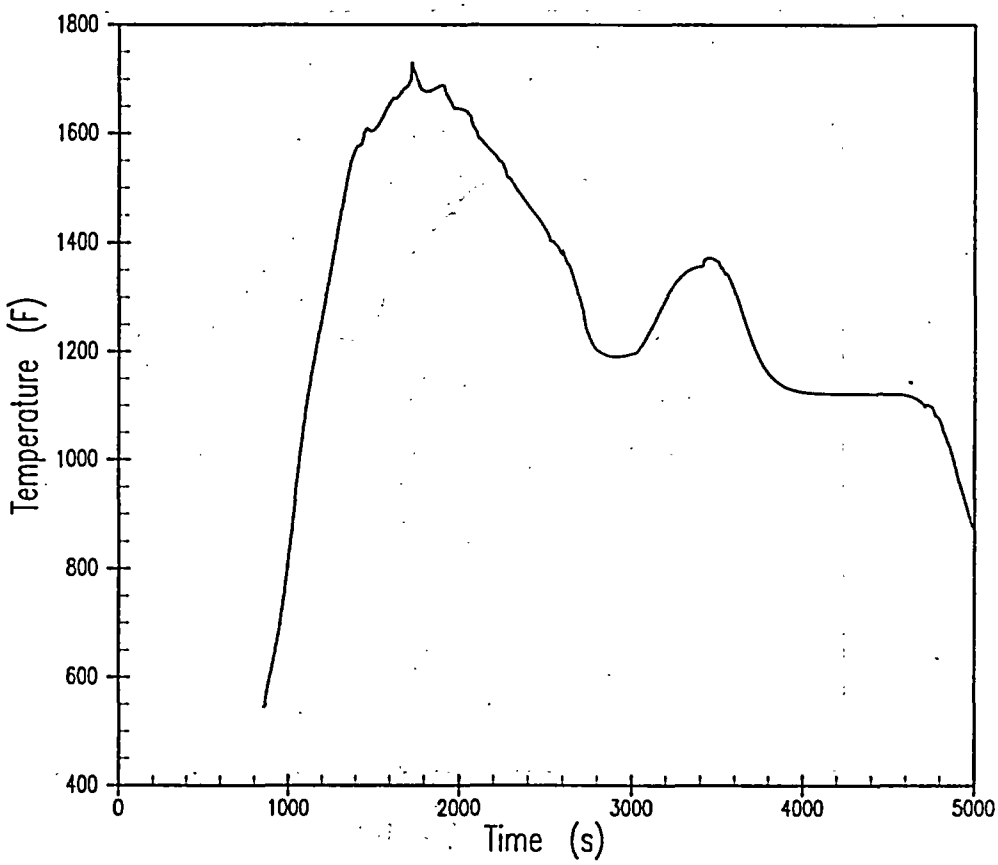


Figure 5.2.2-12A
BVPS-1 3-inch Break
Peak Clad Temperature

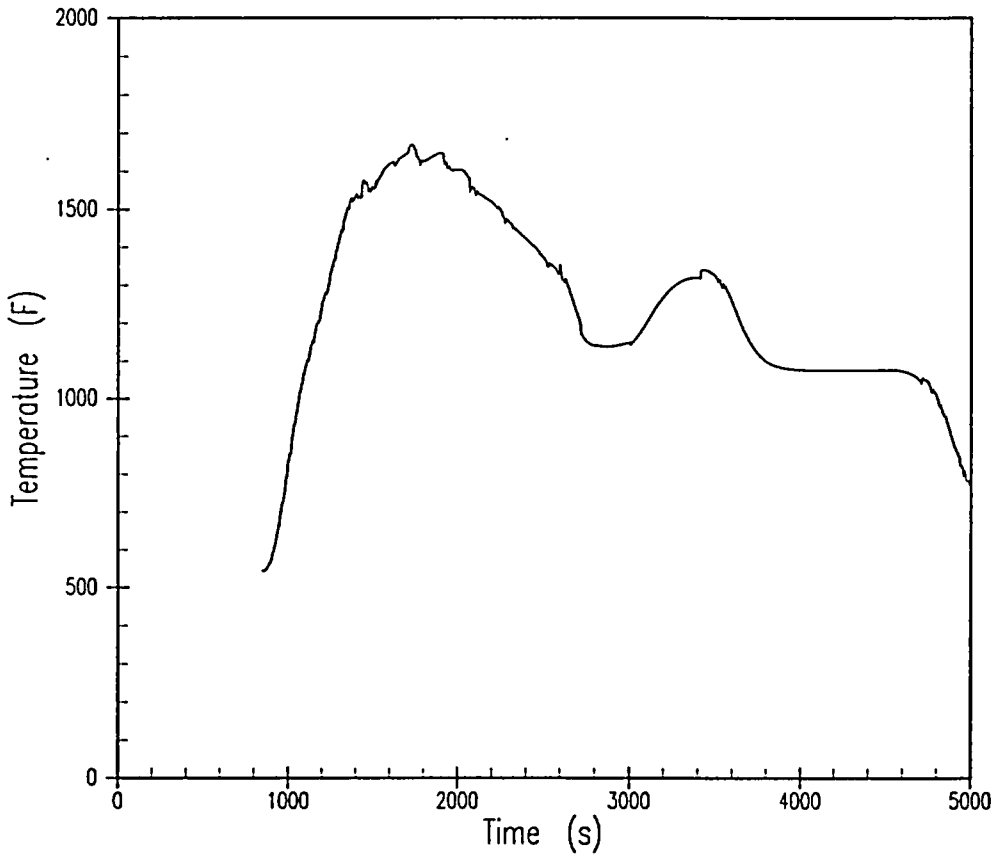


Figure 5.2.2-13A
BVPS-1 3-inch Break
Hot Spot Fluid Temperature

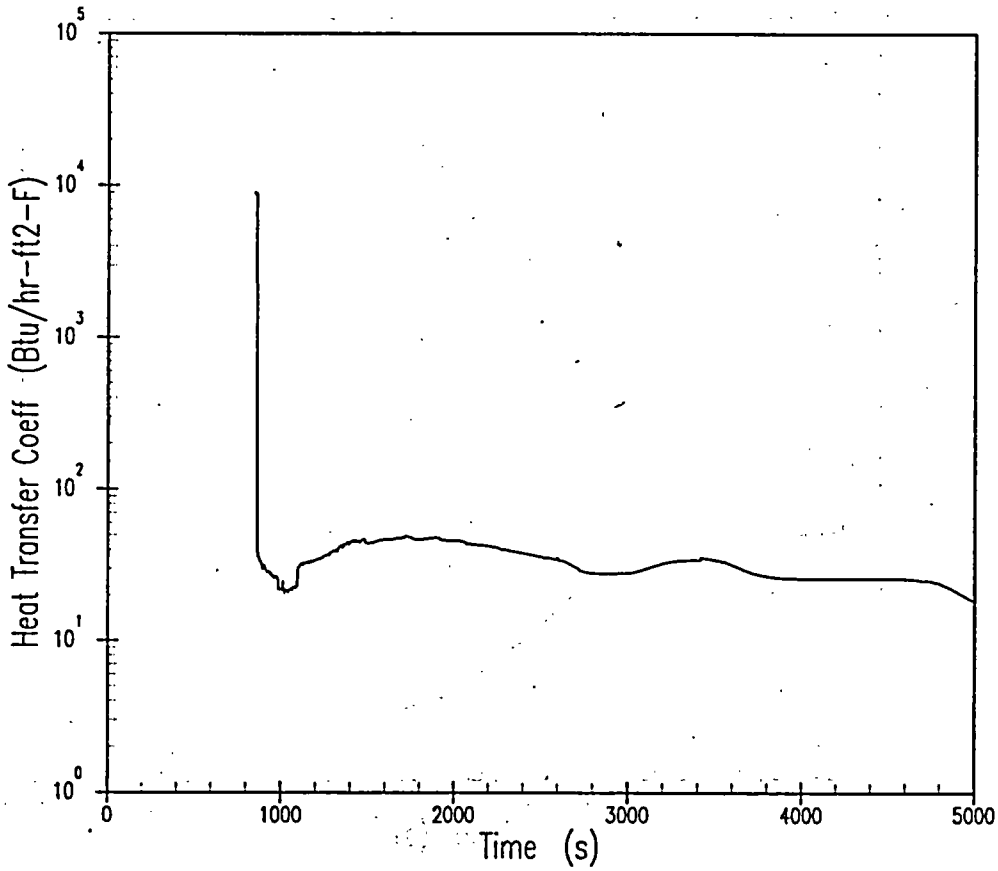


Figure 5.2.2-14A
BVPS-1 3-inch Break
Rod Film Heat Transfer Coefficient

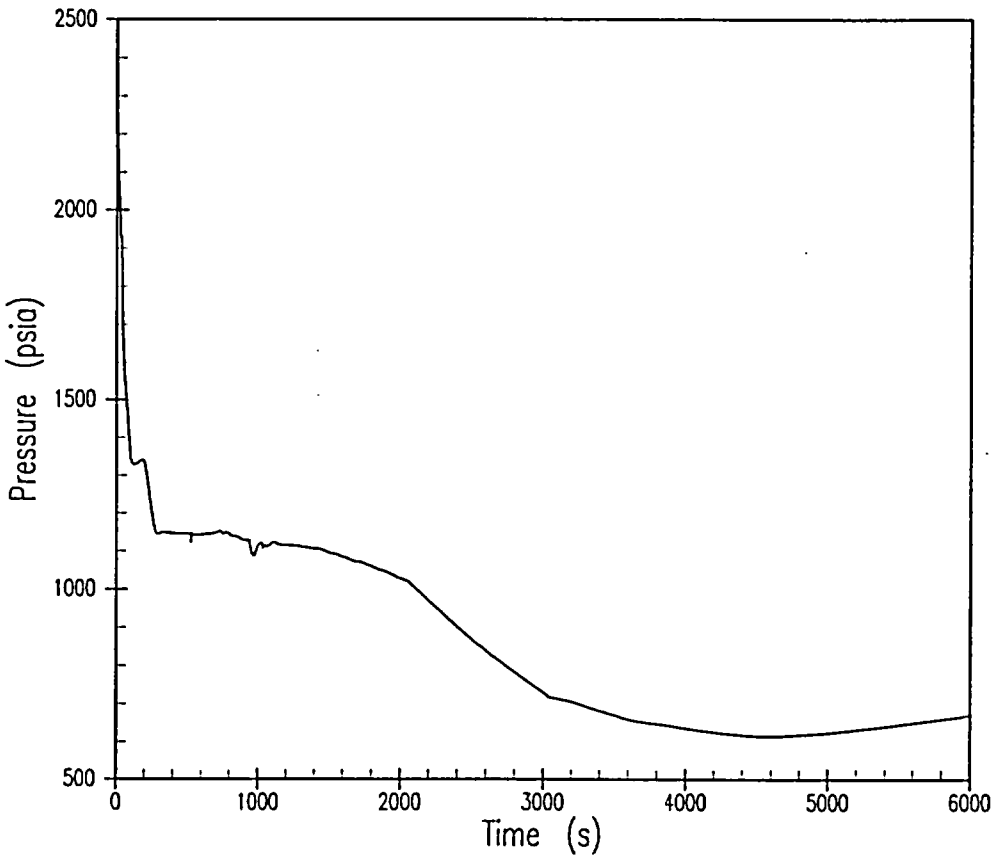


Figure 5.2.2-15A
BVPS-1 2-inch Break
RCS Pressure

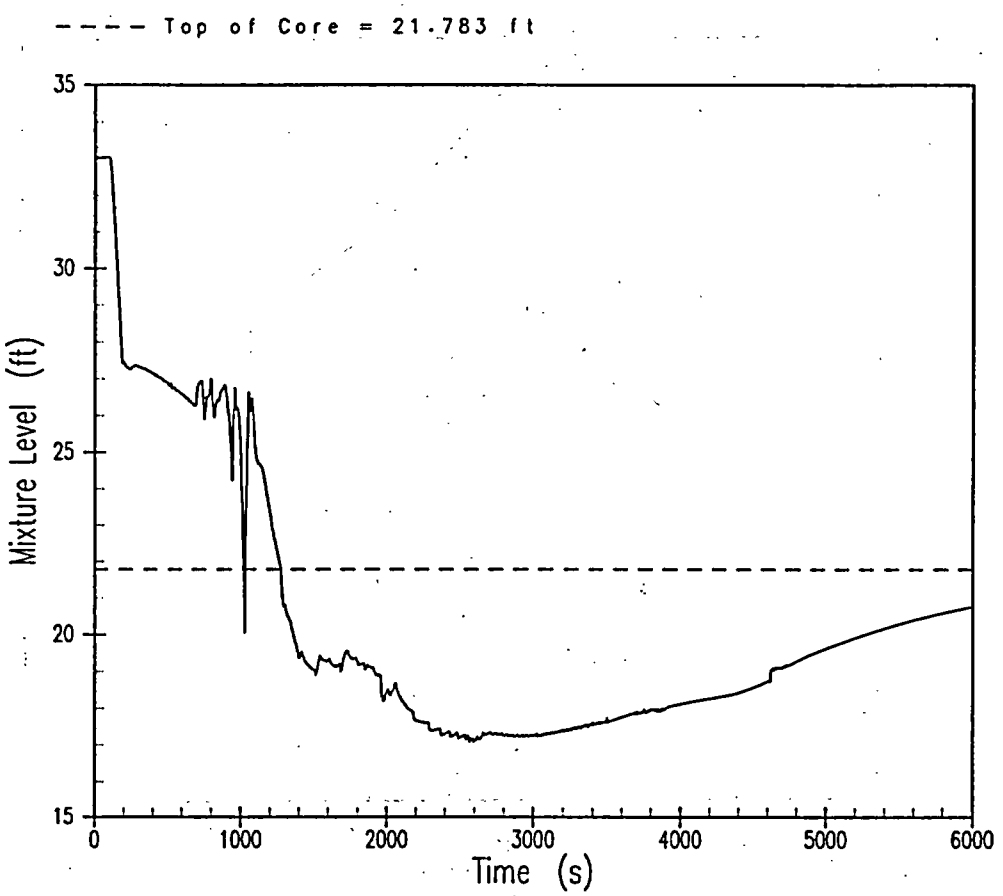


Figure 5.2.2-16A
BVPS-1 2-inch Break
Core Mixture Level

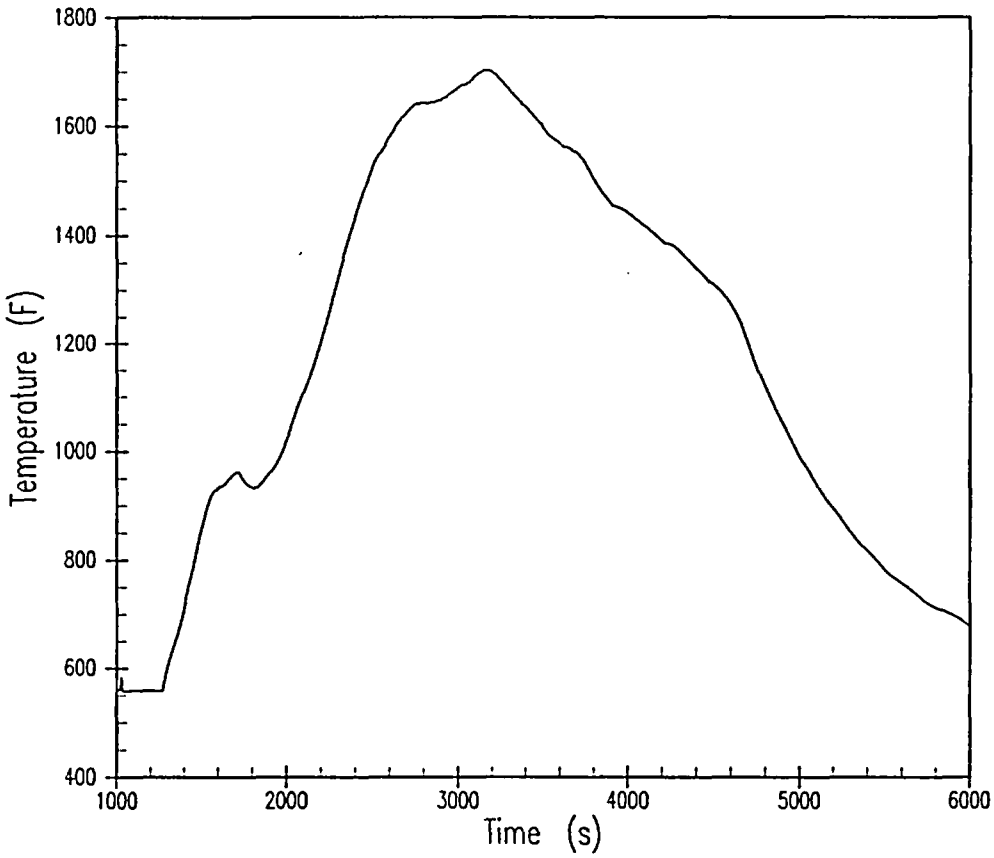


Figure 5.2.2-17A
BVPS-1 2-inch Break
Peak Clad Temperature

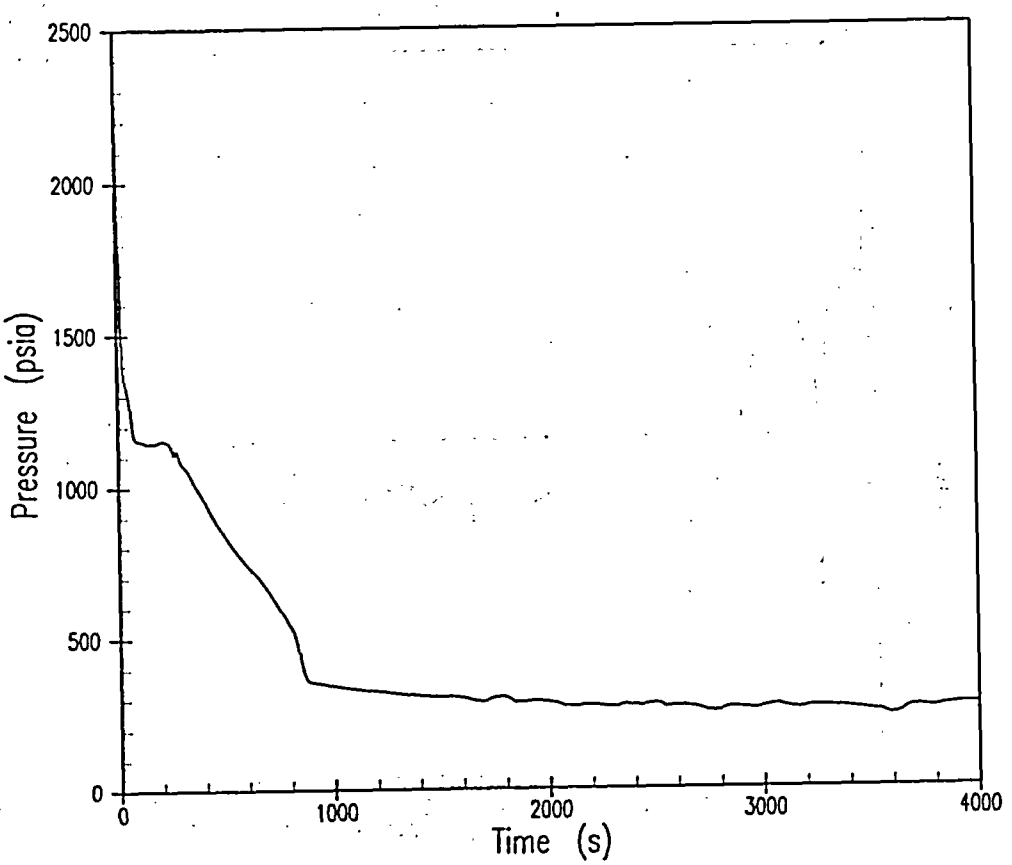


Figure 5.2.2-18
BVPS-1 4-inch Break
RCS Pressure

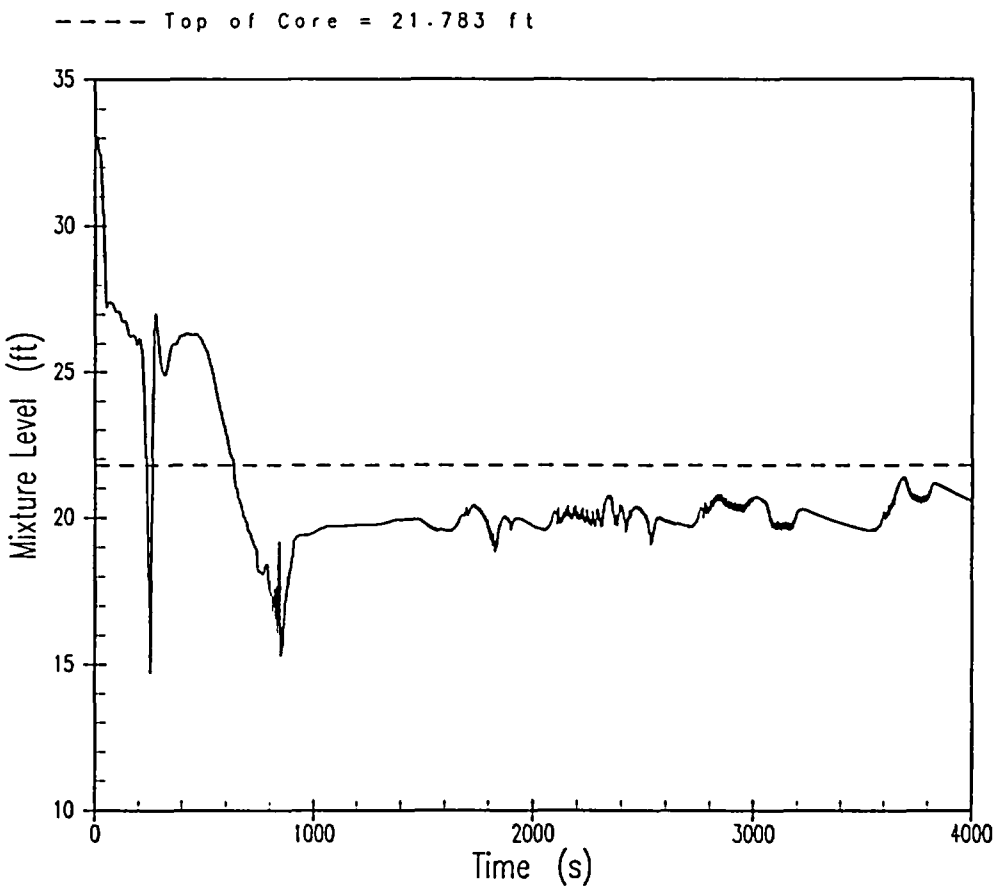


Figure 5.2.2-19
BVPS-1 4-inch Break
Core Mixture Level

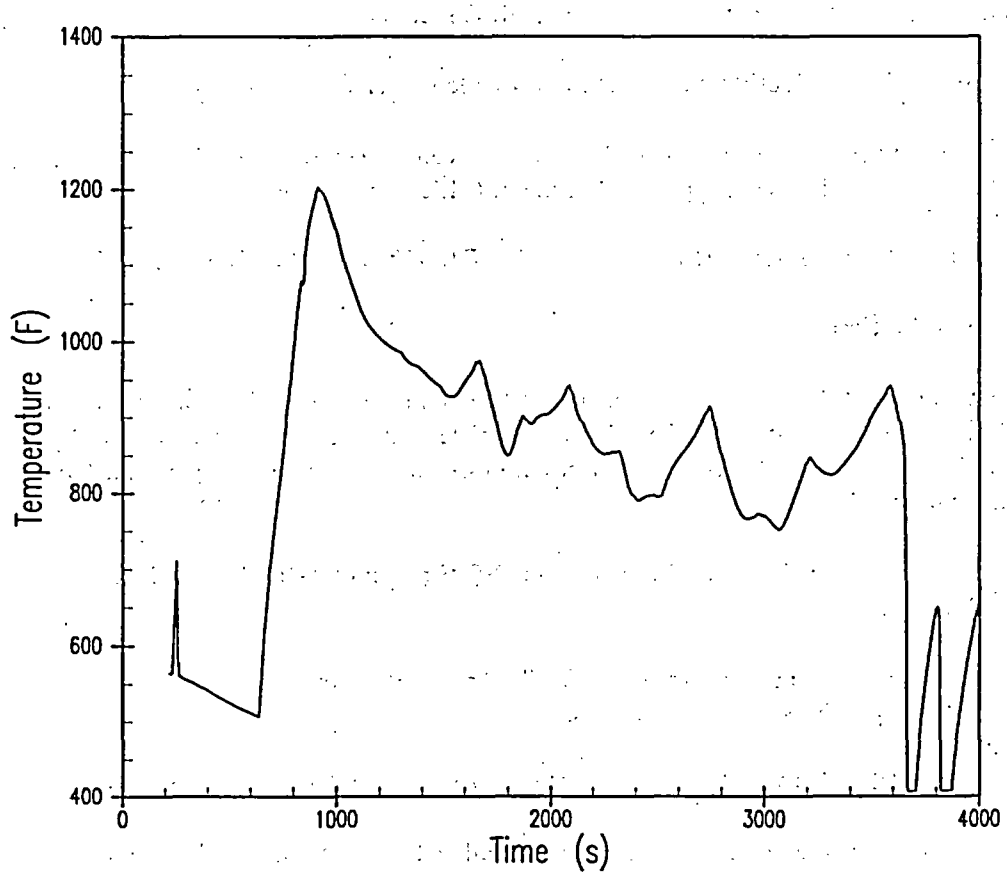


Figure 5.2.2-20
BVPS-1 4-inch Break
Peak Clad Temperature

5.2.3 Hot Leg Switchover (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.2.4 Post-LOCA Subcriticality and Long-Term Core Cooling (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.2.5 Control Rod Ejection Accident Steam Releases (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.3 NON-LOSS OF COOLANT ACCIDENT (NON-LOCA) TRANSIENTS

5.3.1 Introduction

The UFSAR non-LOCA analyses applicable to BVPS-1 were reviewed to determine their continued acceptability for operation at the EPU conditions associated with the NSSS power of 2910 MWt (reactor power of 2900 MWt). For BVPS-1, the analyses discussed in this section were performed to support the replacement Model 54F steam generators.

The non-LOCA events analyzed for BVPS-1 for the NSSS power of 2910 MWt are listed in Table 5.3.1-1.

Two non-LOCA events are not analyzed specifically for the EPU Project because current methodology does not require an analysis. The first event is:

- BVPS-1 UFSAR 14.1.13 – Accidental Depressurization of the Main Steam System

This event is commonly referred to as a Credible Steamline Break. It is always bounded by the analysis of the large steamline break (referred to as the Hypothetical Steamline Break) presented in BVPS-1 UFSAR Section 14.2.5.1. It is presented in this report in Section 5.3.12. The Hypothetical Steamline Break is a Condition IV event which is analyzed to Condition II acceptance criteria. The Credible Steamline Break is a Condition II event. Since the more severe Condition IV event is shown to meet the more restrictive Condition II acceptance criteria, it can be concluded that the Credible Steamline Break event also meets the Condition II acceptance criteria. As such, the analyses presented in BVPS-1 UFSAR Section 14.1.13 do not represent BVPS-1 with a NSSS power of 2910 MWt but have been retained in the UFSAR for historical purposes.

The other non-LOCA event that is no longer analyzed is:

- BVPS-1 UFSAR 14.1.6 – Startup of an Inactive Reactor Coolant Loop

The Technical Specifications prohibit power operation with less than all three Reactor Coolant Pumps in operation. Thus, this event is not credible and the Startup of an Inactive Reactor Coolant Loop event is no longer analyzed. As such, the analyses presented in BVPS-1 UFSAR Section 14.1.6 do not represent BVPS-1 with a NSSS power of 2910 MWt but have been retained in the UFSAR for historical purposes.

One additional non-LOCA event that is not currently presented in the UFSAR has been analyzed for the EPU to 2910 MWt. This is the Steamline Break initiated from Hot Full Power conditions. Prior to this EPU, it was assumed that the limiting steamline break is a break initiated from Hot Zero Power as presented in BVPS-1 UFSAR Section 14.2.5.1. This assumption is based on the conclusions of WCAP-9226 (Reference 1). Specifically, based on the presence of an Overpower ΔT (OPΔT) trip function and specific dynamic compensation, that the OPΔT trip will provide protection for any case initiated at power prior to exceeding the DNB design basis. Coincident with the EPU to 2910 MWt, filters are being added and/or modified on the ΔT and T_{avg} signals that are input to the OPΔT protective function. With these filters, the dynamic compensation is no longer consistent with that assumed in WCAP-9226. As such, a steamline break event initiated at Hot Full Power conditions is now explicitly analyzed for BVPS-1. This analysis is discussed in detail in Section 5.3.19 of this report.

RTDP Methodology

Where applicable, the non-LOCA analyses utilize the Revised Thermal Design Procedure (RTDP) methodology (Reference 2). The RTDP methodology statistically convolutes the uncertainties of the plant operating parameters (power, temperature, pressure and flow) into the design limit Departure from Nucleate Boiling Ratio (DNBR) value. These design limit DNBR values are then utilized to determine the safety analysis limit DNBR values that are assumed as an acceptance criterion in the DNBR-related non-LOCA analyses.

OTΔT and OPΔT Trips

Revised Overtemperature ΔT and Overpower ΔT (OTΔT/OPΔT) setpoints and time constants were applied in the analyses supporting the EPU to 2910 MWt. The safety analysis OTΔT/OPΔT setpoint values applied are shown in Table 5.3.1-2A for BVPS-1.

Reactor Trips

There are various instrumentation delays associated with each reactor trip function which are modeled directly and considered in the non-LOCA safety analyses. The total delay time is defined as the time delay from the time that trip conditions are reached to the time the rods are free to fall. The safety analysis trip setpoint and maximum time delay assumed for each reactor trip function are shown in Table 5.3.1-3A for BVPS-1.

Key Analysis Assumptions

Key analysis assumptions that are used as input to non-LOCA safety analyses are shown in Table 5.3.1-4A for BVPS-1.

Categorization of Events

The non-LOCA accidents are considered either American Nuclear Society (ANS) Condition II, III, or IV events. The ANS categorizes events based upon expected frequency of occurrence and severity as follows:

Condition I:	Normal Operation and Operational Transients
Condition II:	Faults of Moderate Frequency
Condition III:	Infrequent Faults
Condition IV:	Limiting Faults

Condition I events are normal operation incidents which are expected to occur frequently or regularly. These occurrences are accommodated with the margin between any plant parameter and the value of that parameter that would require either automatic or manual protective action.

Condition II events (which are the majority of the non-LOCA events) are incidents of moderate frequency that may reasonably occur during a calendar year of operation. These faults, at worst, result in a reactor trip with the plant capable of returning to power operations after corrective actions. Condition II incidents shall not generate a more serious accident (Condition III or IV) without other incidents occurring independently.

Condition III events are infrequent faults that may reasonably occur during the lifetime of a plant. These faults shall not cause more than a small fraction of fuel elements to be damaged. No consequential loss of function of the RCS or containment as fission product barriers can occur. The release of radioactive materials to unrestricted areas may exceed normal operating limits; however, they shall not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. Condition III incidents shall not generate a more serious accident (Condition IV) without other incidents occurring independently.

Condition IV events are limiting faults that are not expected to occur but are postulated because their consequences would include the potential for significant radioactive releases. The release of radioactive material shall not result in an undue risk to public health and safety exceeding the guidelines of 10 CFR 50.67. No consequential loss of function of systems required to mitigate the event may occur.

References

1. WCAP-9226-P-A, Rev. 1, "Reactor Core Response to Excessive Secondary Steam Releases," S. D. Hollingsworth and D. C. Wood, February 1998 (Proprietary).

2. WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non Proprietary), "Revised Thermal Design Procedure," Friedland, A. J. and Ray, S., April 1989.

Table 5.3.1-1
Summary of Non-LOCA Events

Report Section	BVPS Unit	UFSAR Section	UFSAR Non-LOCA Event[1]
5.3.2	BVPS-1	14.1.1	Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition
	BVPS-2	NA	NA
5.3.3	BVPS-1	14.1.2	Uncontrolled RCCA Bank Withdrawal at Power
	BVPS-2	NA	NA
5.3.4	BVPS-1	14.1.3	RCCA Misalignment
	BVPS-2	NA	NA
5.3.5	BVPS-1	14.1.4	Uncontrolled Boron Dilution
	BVPS-2	NA	NA
5.3.6	BVPS-1	14.1.7	Loss of External Electrical Load and/or Turbine Trip
	BVPS-2	NA	NA
5.3.7	BVPS-1	14.1.8	Loss of Normal Feedwater
	BVPS-2	NA	NA
5.3.8	BVPS-1	14.1.11	Loss of Offsite Power to the Station Auxiliaries (Station Blackout)
	BVPS-2	NA	NA
5.3.9	BVPS-1	14.1.9	Excessive Heat Removal Due to Feedwater System Malfunctions
	BVPS-2	NA	NA
5.3.10	BVPS-1	14.1.10	Excessive Load Increase Incident
	BVPS-2	NA	NA
5.3.11	BVPS-1	14.1.15	Accidental Depressurization of the Reactor Coolant System
	BVPS-2	NA	NA
5.3.12	BVPS-1	14.2.5.1	Major Rupture of a Main Steam Pipe
	BVPS-2	NA	NA
5.3.13	BVPS-1	14.1.5	Partial Loss of Forced Reactor Coolant Flow
	BVPS-2	NA	NA
5.3.14	BVPS-1	14.2.9	Complete Loss of Forced Reactor Coolant Flow
	BVPS-2	NA	NA

Table 5.3.1-1 (continued)
Summary of Non-LOCA Events

Report Section	BVPS Unit	UFSAR Section	UFSAR Non-LOCA Event[1]
5.3.15	BVPS-1	14.2.7	Single Reactor Coolant Pump Locked Rotor
	BVPS-2	NA	NA
5.3.16	BVPS-1	14.2.6	Rupture of a Control Rod Drive Mechanism Housing RCCA Ejection (EPU Section)
	BVPS-2	NA	NA
5.3.17	BVPS-1	14.2.5.2	Major Rupture of a Main Feedwater Pipe
	BVPS-2	NA	NA
5.3.18	BVPS-1	14.1.16	Spurious Operation of the Safety Injection System at Power (EPU Section)
	BVPS-2	NA	NA
5.3.19	BVPS-1	N/A[2]	Steam System Piping Failure at Full Power
	BVPS-2	NA	NA

Notes:

(1) The information in the report section applies to the Non-LOCA events in the corresponding UFSAR sections even though the UFSAR event name might be different from that used in the report section.

(2) The BVPS-1 UFSAR does not include this event for current power conditions.

Table 5.3.1-2A
BVPS-1 Overtemperature ΔT and Overpower ΔT Setpoints

OTΔT	OPΔT
$K1_{Analysis}$ = 1.330[1]	$K4_{Analysis}$ = 1.146[1]
K2 = 0.0183	K5 = 0.02
K3 = 0.001	K6 = 0.0021
f(ΔI) + wing = 10%, %ΔI = 1.47%	f(ΔI) = 0
- wing = -48%, %ΔI = 4.67%	

Note:
(1) Where applicable, K1 = 1.34157 and/or K4 = 1.15597 were used to account for RCS temperature asymmetry.

Table 5.3.1-3A
BVPS-1 Non-LOCA Reactor Trip Safety Analysis Limit Setpoints and Time Delays

Reactor Trip Function	Time Delay (seconds)	Trip Setpoint Assumed in the Analysis (SAL)
Power Range Flux (high setting)	0.5	116%
Power Range Flux (low setting)	0.5	35%
Overtemperature ΔT	(1)	Variable (see Table 5.3.1-2A)
Overpower ΔT	(1)	Variable (see Table 5.3.1-2A)
High Pressurizer Pressure	2.0	2435 psia
Low Pressurizer Pressure	2.0	1935 psia
Low Reactor Coolant Flow	1.0	87% of loop flow
Low Steam Pressure SI (compensated)	3.0	460 psia(2)
Low-Low Steam Generator Water Level		
(LONF/LOOP events)	2.0	5% NRS
(Feedline Break event)	2.0	0% NRS
High-High Steam Generator Water Level		
(Feedwater Isolation)	10.0 (at full power)	100% NRS
(Turbine Trip)	2.5	100% NRS
Reactor Trip (following Turbine Trip)(3)	2.0	N/A

Notes:

(1) Response time modeled in non-LOCA UFSAR Chapter 14 safety analyses as a 6 second lag function followed by a 2 second electronics (pure) delay. Also, included in the analysis are a 2 second filter on the vessel T_{avg} signal and a 6 second filter on the ΔT signal.

(2) A 50/5 lead/lag is applied to this setpoint.

(3) This trip is credited only as an anticipatory trip in the Feedwater Malfunction event. No credit is taken for a direct reactor trip following a turbine trip in the Loss of Load analysis.

Table 5.3.1-4A BVPS-1 Non-LOCA Key Accident Analysis Assumptions	
NSSS Thermal Design Flow (per Loop)	87,200 gpm
Minimum Measured Flow (per Loop)	88,933 gpm
Programmed Full Power Vessel Average Temperature	580.0° to 566.2°F
Maximum Steam Generator Tube Plugging Level	22%
Max $F_{\Delta H}$	1.56 (RTDP) 1.62 (STDP)
DNB Methodology (where applicable)	RTDP
Max EOL MDC	0.43 Δk/g/cc
Max BOL MTC	+5 pcm/°F ≤70% RTP ramping to 0 at 100% RTP
Initial Condition Uncertainties:	
Power	+/- 0.6% RTP
Temperature	+/- 4.0°F(1)
Pressure	+/- 40 psi
Steam Generator Water Level	+/- 10% NRS
Pressurizer Water Level	+/- 7% span

Notes:

(1) The analyses also include ±3.5°F for loop-to-loop asymmetry, -2°F to allow for intentional operation below the design average temperature and a +1°F bias.

5.3.2 Uncontrolled RCCA Bank Withdrawal From a Subcritical Condition

5.3.2.1 Identification of Causes and Accident Description

An uncontrolled rod cluster control assembly (RCCA) withdrawal incident is defined as an uncontrolled addition of reactivity to the reactor core by withdrawal of rod cluster control assemblies resulting in a power excursion. While the probability of a transient of this type is extremely low, such a transient could be caused by operator action or a malfunction of the reactor control rod drive system. This could occur with the reactor either subcritical or at power. The "at power" occurrence is discussed in Section 5.3.3.

Reactivity is added at a prescribed and controlled rate in bringing the reactor from a shutdown condition to a low power level during startup by RCCA withdrawal or by reducing the core boron concentration. RCCA motion can cause much faster changes in reactivity than can result from changing boron concentration.

The rods are physically prevented from withdrawing in other than their respective banks. Power supplied to the rod banks is controlled such that no more than two banks can be withdrawn at any time. The rod drive mechanism is of the magnetic latch type and the coil actuation is sequenced to provide variable speed rod travel. The maximum reactivity insertion rate is analyzed in the detailed plant analysis assuming the simultaneous withdrawal of the combination of the two rod banks with the maximum combined worth at maximum speed, which is well within the capability of the protection system to prevent core damage.

Should a continuous RCCA withdrawal be initiated and assuming the source and intermediate range indication and annunciators are ignored, the transient will be terminated by one of the following automatic protective functions:

a. Source range neutron flux reactor trip – actuated when either of two independent source range channels indicates a flux level above a preselected, manually adjustable value. This trip function may be manually bypassed when either intermediate range flux channel indicates a flux level above a specified level. It is automatically reinstated when both intermediate channels indicate a flux level below a specified level.

b. Intermediate range neutron flux reactor trip – actuated when either of two independent intermediate range channels indicates a flux level above a preselected, manually adjustable value. This trip function may be manually bypassed when two of the four power range channels are reading above approximately 10% of the full-power flux and is automatically reinstated when three of the four channels indicate a flux level below this value.

c. Power range neutron flux reactor trip (low setting) – actuated when two out of the four power range channels indicate a flux level above approximately 25% of the full-power flux. This trip function may be manually bypassed when two of the four power range channels indicate a flux level above approximately 10% of the full-power flux and is automatically reinstated when three of the four channels indicate a flux level below this value.

d. Power range neutron flux reactor trip (high setting) – actuated when two out of the four power range channels indicate a power level above a preset setpoint (≤109% of the full-power flux). This trip function is always active when the control rods are capable of being withdrawn.

e. High positive neutron flux rate reactor trip – actuated when the positive rate of change of neutron flux on two out of four power range channels indicates a rate above the preset setpoint. This trip function is always active when in Modes 1 and 2.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the initial power increase results from a fast negative fuel temperature feedback (Doppler effect) and is of prime importance during a startup transient since it limits the power to an acceptable level prior to protection system action. After the initial power increase, the nuclear power is momentarily reduced and then, if the incident is not terminated by a reactor trip, the nuclear power increases again, but at a much slower rate.

Termination of the startup transient by the above protection channels prevents core damage. In addition, the reactor trip from high pressurizer pressure (a trip function which is always active when in Modes 1 and 2) serves as backup to terminate the event before an overpressure condition could occur.

5.3.2.2 Input Parameters and Assumptions

The accident analysis employs the Standard Thermal Design Procedure (STDP) methodology since the conditions resulting from the transient are outside the range of applicability of the RTDP methodology. In order to obtain conservative results for the analysis of the uncontrolled RCCA bank withdrawal from subcritical event, the following assumptions are made concerning the initial reactor conditions:

a. Since the magnitude of the nuclear power peak reached during the initial part of the transient, for any given rate of reactivity insertion, is strongly dependent on the Doppler-only power defect, a conservatively low absolute value of 962 pcm is used.

b. The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time constant between the fuel and moderator is much longer than the nuclear flux response time constant. However, after the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. Accordingly, a most-positive moderator temperature coefficient (+5 pcm/°F) is used since this yields the maximum rate of power increase.

c. The analysis assumes the reactor to be at hot zero power conditions with a nominal temperature of 547°F. This assumption is more conservative than that of a lower initial system temperature (i.e., shutdown conditions). The higher initial system temperature yields a larger fuel-to-moderator heat transfer coefficient, a larger specific heat of the moderator and fuel, and a less-negative (smaller absolute magnitude) Doppler defect. The less-negative Doppler defect reduces the Doppler feedback effect, thereby increasing the neutron flux peak. The high neutron flux peak combined with a high fuel specific heat and larger heat transfer coefficient yields a

larger peak heat flux. The analysis assumes the initial effective multiplication factor (K_{eff}) to be 1.0 since this results in the maximum neutron flux peak.

d. Reactor trip is assumed on power range high neutron flux (low setting). The most adverse combination of instrumentation error, setpoint error, delay for trip signal actuation, and delay for control rod assembly release is taken into account. The analysis assumes a 10% uncertainty in the power range flux trip setpoint (low setting), raising it from the nominal value of 25% to a value of 35%; no credit is taken for the source and intermediate range protection. During the transient, the rise in nuclear power is so rapid that the effect of error in the trip setpoint on the actual time at which the rods release is negligible. In addition, the total reactor trip reactivity is based on the assumption that the highest worth rod cluster control assembly is stuck in its fully withdrawn position.

e. The maximum positive reactivity insertion rate assumed is greater than that for the simultaneous withdrawal of the two sequential control banks having the greatest combined worth at the maximum speed (48.125 in/min, which corresponds to 77 steps/min).

f. The DNB analysis assumes the most-limiting axial and radial power shapes possible during the fuel cycle associated with having the two highest combined worth banks in their highest worth position.

g. The analysis assumes the initial power level to be below the power level expected for any shutdown condition (10^{-9} fraction of nominal power). The combination of highest reactivity insertion rate and low initial power produces the highest peak heat flux.

h. The analysis assumes two RCPs to be in operation (Mode 3 Technical Specification allowed operation). This is conservative with respect to the DNB transient.

i. This accident analysis employs the Standard Thermal Design Procedure (STDP) methodology. The use of STDP stipulates that the RCS flow rates will be based on a fraction of the thermal design flow for two RCPs operating. Since the event is analyzed from hot zero power, the steady-state non-RTDP uncertainties are not considered in defining the initial conditions.

5.3.2.3 Description of Analysis

The analysis of the uncontrolled RCCA bank withdrawal from subcriticality is performed in three stages. First, a spatial neutron kinetics computer code, TWINKLE (Reference 1), is used to calculate the core average nuclear power transient, including the various core feedback effects, i.e., Doppler and moderator reactivity. Next, the FACTRAN computer code (Reference 2) uses the average nuclear power calculated by TWINKLE and performs a fuel rod transient heat transfer calculation to determine the core average heat flux and hot spot fuel temperature transients. Finally, the core average heat flux calculated by FACTRAN is used in the VIPRE computer code (Reference 3) for transient DNBR calculations.

5.3.2.4 Acceptance Criteria and Results

The Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from Subcritical event is considered an ANS Condition II event, a fault of moderate frequency, and is analyzed to show that the core and reactor coolant system are not adversely affected. This is demonstrated by showing that the DNB design basis is not violated and subsequently there is little likelihood of core damage. It must also be shown that the peak hot spot fuel and clad temperatures remain within acceptable limits, although for this event, the heat up is relatively small.

The analysis shows that all applicable acceptance criteria are met. The minimum DNBR never goes below the limit value and the peak fuel centerline temperature is 2363°F which is well below the minimum temperature where fuel melting would be expected (4800°F). Figure 5.3.2-1 shows the nuclear power and core average heat flux transients and Figure 5.3.2-2 shows the inner clad and fuel average temperature transient at the hot spot.

5.3.2.5 Conclusions

In the event of an RCCA withdrawal event from subcritical conditions, the core and the RCS are not adversely affected since the combination of thermal power and coolant temperature results in a minimum DNBR greater than the safety analysis limit value. Furthermore, since the maximum fuel temperatures predicted to occur during this event are much less than those required for fuel melting to occur, no fuel damage is predicted as a result of this transient. Clad damage is also precluded.

The results and conclusions of the analysis performed for the uncontrolled RCCA bank withdrawal from a subcritical condition for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

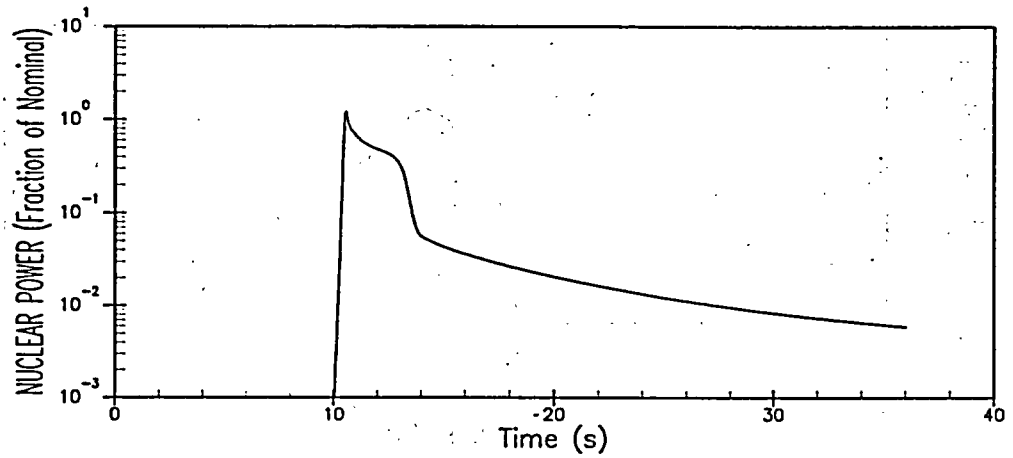
5.3.2.6 References

1. Barry, R. F., Jr. and Risher, D. H., "TWINKLE, a Multi-dimensional Neutron Kinetics Computer Code," WCAP-7979-P-A, January 1975 (Proprietary) and WCAP-8028-A, January 1975 (Non-Proprietary).

2. Hargrove, H. G., "FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908, December 1989.

3. Sung, Y. X. et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), October 1999.

Table 5.3.2-1 Time Sequence of Events – Uncontrolled RCCA Withdrawal from a Subcritical Condition	
Event	**Time (sec)**
Initiation of uncontrolled rod withdrawal from 10^{-9} of nominal power	0.0
Power Range high neutron flux low setpoint reached	10.4
Peak nuclear power occurs	10.6
Rods begin to fall into core	10.9
Minimum DNBR occurs	12.6
Peak heat flux occurs	12.6
Peak average clad temperature occurs	13.1
Peak average fuel temperature occurs	13.3



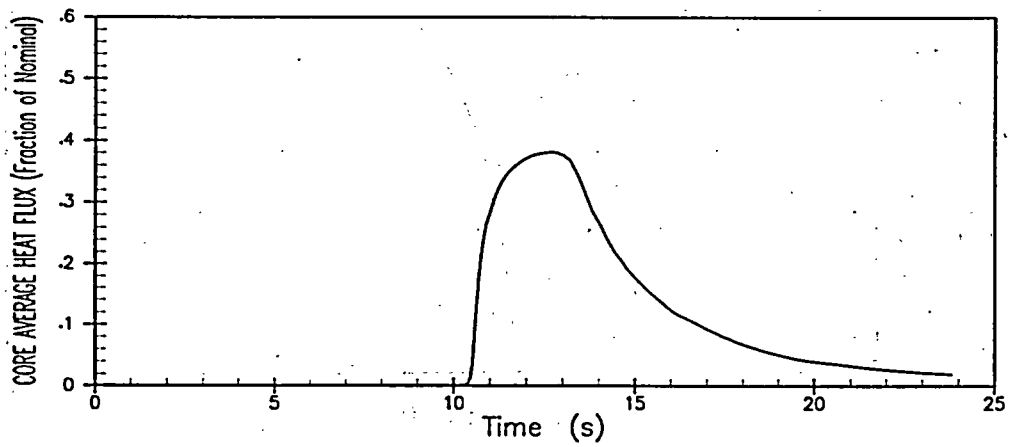
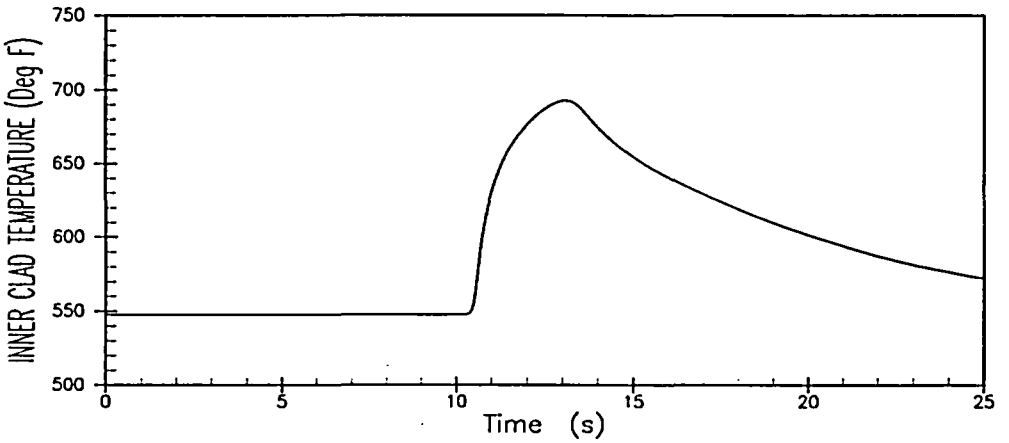


Figure 5.3.2-1
Rod Withdrawal from Subcritical
Nuclear Power and Core Average Heat Flux versus Time



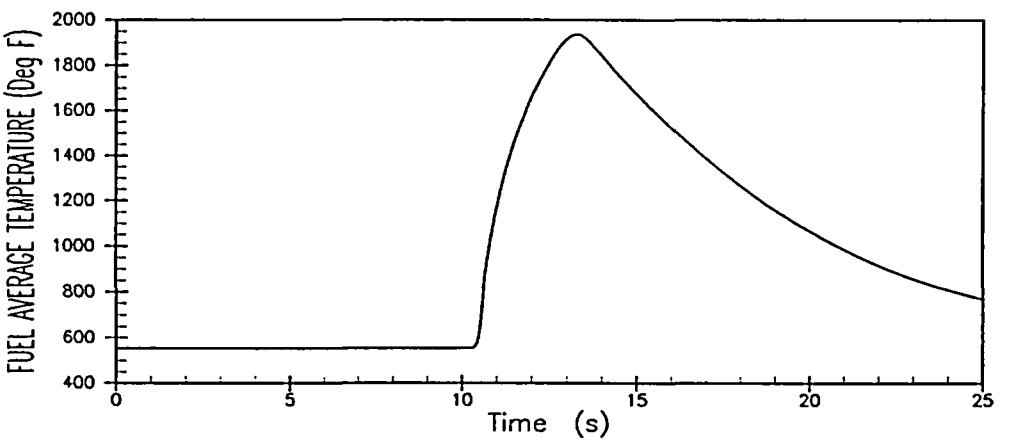


Figure 5.3.2-2
Rod Withdrawal from Subcritical
Hot Spot Fuel Temperatures versus Time

5.3.3 Uncontrolled RCCA Bank Withdrawal at Power

5.3.3.1 Identification of Causes and Accident Description

An uncontrolled rod cluster control assembly (RCCA) withdrawal at power which causes an increase in core heat flux may result from faulty operator action or a malfunction in the rod control system. Immediately following the initiation of the accident, the steam generator heat removal rate lags behind the core power generation rate until the steam generator pressure reaches the setpoint of the steam generator relief or safety valves. This imbalance between heat removal and heat generation rate causes the reactor coolant temperature to rise. Unless terminated, the power mismatch and resultant coolant temperature rise could eventually result in a violation of the DNBR limit and/or fuel centerline melt. Therefore, to avoid damage to the core, the reactor protection system is designed to automatically terminate any such transient before the DNBR falls below the safety analysis limit value or the fuel rod linear heat generation rate (kw/ft) limit is exceeded.

The automatic features of the reactor protection system which prevent core damage in a RCCA bank withdrawal incident at power include the following:

a. Power range high neutron flux instrumentation actuates a reactor trip on neutron flux if two-out-of-four channels exceed an overpower setpoint.

b. Reactor trip actuates if any two-out-of-three ΔT channels exceed an overtemperature ΔT setpoint in two-out-of-three loops. This setpoint is automatically varied with axial power distribution, coolant average temperature, and coolant average pressure to protect against violating the DNBR limit.

c. Reactor trip actuates if any two-out-of-three ΔT channels exceed an overpower ΔT setpoint in two-out-of-three loops. This setpoint is automatically varied with coolant average temperature so that the allowable heat generation rate (kw/ft) is not exceeded.

d. A high pressurizer pressure reactor trip actuates if any two-out-of-three pressure channels exceed a fixed setpoint. This reactor trip on high pressurizer pressure is less than the set pressure for the pressurizer safety valves.

e. A high pressurizer water level reactor trip actuates if any two-out-of-three level channels exceed a fixed setpoint.

f. A positive neutron flux reactor trip actuates if any two-out-of-four channels exceed a fixed setpoint.

Besides the above listed reactor trips, several RCCA withdrawal blocks which are not credited in the accident analyses but would serve to limit the severity of this event are listed below:

a. High neutron flux (one-out-of-four power range)
b. Overpower ΔT (two-out-of-three channels)
c. Overtemperature ΔT (two-out-of-three channels)

5.3.3.2 Input Parameters and Assumptions

A number of cases were analyzed assuming a range of reactivity insertion rates for both minimum and maximum reactivity feedback conditions at various power levels. The cases presented in Section 5.3.3.4 are representative for this event.

For an uncontrolled RCCA bank withdrawal at power accident, the analysis assumes the following conservative assumptions:

a. This accident is analyzed with the Revised Thermal Design Procedure (Reference 2). Initial reactor power, RCS pressure, and RCS temperature are assumed to be at their nominal values, adjusted to account for any applicable measurement biases, consistent with steady-state full power operation. Minimum Measured Flow is modeled. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 2.

b. For reactivity coefficients, two cases are analyzed.

   1. Minimum Reactivity Feedback: A +5 pcm/°F moderator temperature coefficient and a least-negative Doppler-only power coefficient form the basis for the beginning-of-life (BOL) minimum reactivity feedback assumption.

   2. Maximum Reactivity Feedback: A conservatively large positive moderator density coefficient of 0.43 $\Delta k/g/cm^3$ (corresponding to a large negative moderator temperature coefficient) and a most-negative Doppler-only power coefficient form the basis for the end-of-life (EOL) maximum reactivity feedback assumption.

c. The reactor trip on high neutron flux is assumed to be actuated at a conservative value of 116% of nominal full power. The ΔT trips include all adverse instrumentation and setpoint errors, while the delays for the trip signal actuation are assumed at their maximum values.

d. The RCCA trip insertion characteristic is based on the assumption that the highest-worth rod cluster control assembly is stuck in its fully withdrawn position.

e. A range of reactivity insertion rates are examined. The maximum positive reactivity insertion rate is greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined worth at a conservative speed (48.125 inches/minute, which corresponds to 77 steps/minute).

f. Power levels of 10, 60 and 100% of the NSSS power of 2910 MWt are considered.

5.3.3.3 Description of Analysis

The purpose of this analysis is to demonstrate the manner in which the protection functions described above actuate for various combinations of reactivity insertion rates and initial conditions. Insertion rate and initial conditions determine which trip function actuates first.

The uncontrolled rod withdrawal at power event is analyzed with the LOFTRAN computer code (Reference 1). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and main steam safety valves. The program computes pertinent plant variables including temperatures, pressures, power level, and departure from nucleate boiling ratio.

5.3.3.4 Acceptance Criteria and Results

Based on its frequency of occurrence, the uncontrolled RCCA bank withdrawal at power accident is considered a Condition II event as defined by the American Nuclear Society. The following items summarize the main acceptance criteria associated with this event:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the reactor coolant and main steam systems should be maintained below 110% of the design pressures. With respect to peak pressure, the uncontrolled RCCA bank withdrawal at power accident is bounded by the loss of load/turbine trip analysis. The loss of load/turbine trip analysis is described in Section 5.3.6.

The protection features presented in Section 5.3.3.1 provide mitigation of the uncontrolled RCCA bank withdrawal at power transient such that the above criteria are satisfied.

Figures 5.3.3-1A through 5.3.3-3A show the transient response for a rapid uncontrolled RCCA bank withdrawal incident (80 pcm/sec) starting from 100% power with minimum feedback. Reactor trip on high neutron flux occurs shortly after the start of the accident. Because of the rapid reactor trip, small changes in T_{avg} and pressure result in the margin to the DNBR limit being maintained.

The transient response for a slow uncontrolled RCCA bank withdrawal (0.4 pcm/sec for BVPS-1) from 100% power with minimum feedback is shown in Figures 5.3.3-4A through 5.3.3-6A. Reactor trip on overtemperature ΔT occurs after a longer period of time, and the rise in temperature is consequently larger than for a rapid RCCA bank withdrawal. Again, the minimum DNBR is greater than the safety analysis limit value.

Figure 5.3.3-7A shows the minimum DNBR as a function of reactivity insertion rate from 100% power for both minimum and maximum reactivity feedback conditions. It can be seen that the high neutron flux and overtemperature ΔT reactor trip functions provide DNB protection over the range of reactivity insertion rates. The minimum DNBR is never less than the safety analysis limit value. The RCS and main steam systems are maintained below 110% of the design pressures.

Figures 5.3.3-8A and 5.3.3-9A show the minimum DNBR as a function of reactivity insertion rate for RCCA bank withdrawal incidents starting at 60 and 10% power, respectively. The results are similar to the 100% power case; however, as the initial power level decreases, the range over which the overtemperature ΔT trip is effective is increased. In all of these cases the DNBR remains above the safety analysis limit value (1.55).

A calculated sequence of events for the two cases is shown in Table 5.3.3-1A. With the reactor tripped, the plant eventually returns to a stable condition. The plant may subsequently be cooled down further by following normal plant shutdown procedures.

5.3.3.5 Conclusions

The high neutron flux and overtemperature ΔT reactor trip functions provide adequate protection over the entire range of possible reactivity insertion rates, i.e., the minimum value of DNBR is always larger than the safety analysis limit value. The RCS and main steam systems are maintained below 110% of the design pressures. Therefore, the results of the analysis show that an uncontrolled RCCA withdrawal at power does not adversely affect the core, the RCS, or the main steam system and all applicable criteria are met.

The results and conclusions of the analysis performed for the uncontrolled RCCA bank withdrawal at power for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

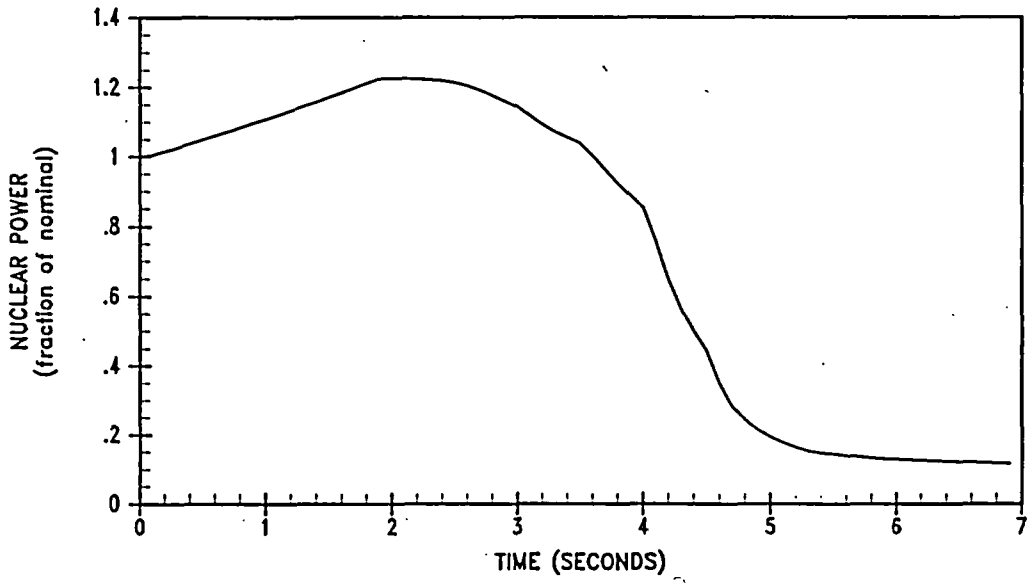
5.3.3.6 References

1. Burnett, T.W.T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.

2. Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), April 1989.

Table 5.3.3-1A
BVPS-1 Time Sequence of Events – Uncontrolled RCCA Bank Withdrawal at Power

Case	Event	Time (sec)
100% Power, Minimum Feedback, Rapid RCCA Withdrawal (80 pcm/sec)	Initiation of Uncontrolled RCCA Withdrawal	0.0
	Power Range High Neutron Flux – High Setpoint Reached	1.4
	Rods Begin to Fall	1.9
	Minimum DNBR Occurs	2.9
100% Power, Minimum Feedback, Slow RCCA Withdrawal (0.4 pcm/sec)	Initiation of Uncontrolled RCCA Withdrawal	0.0
	Overtemperature Delta-T Trip Point Reached	104.1
	Rods Begin to Fall	106.1
	Minimum DNBR Occurs	107.1



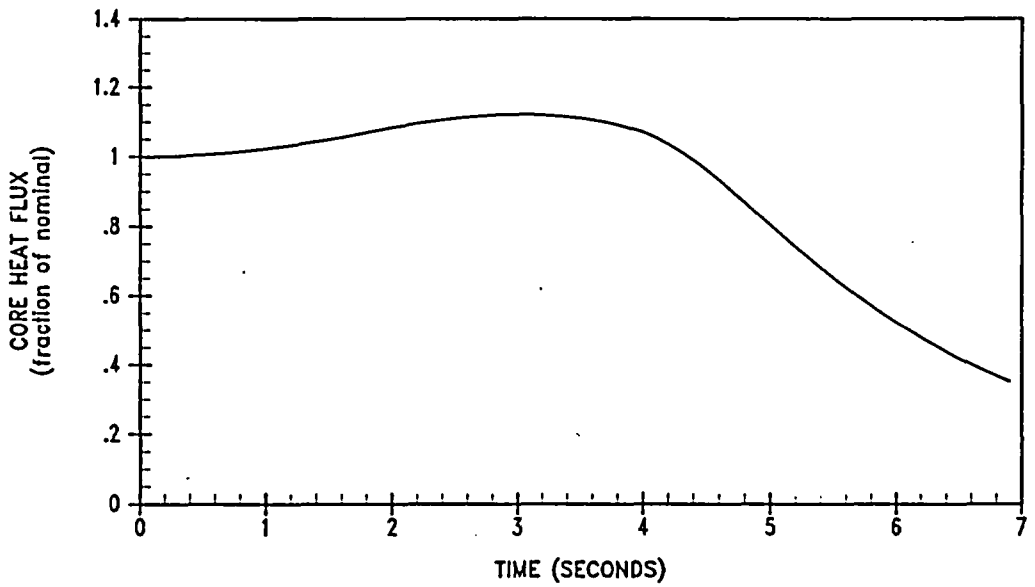
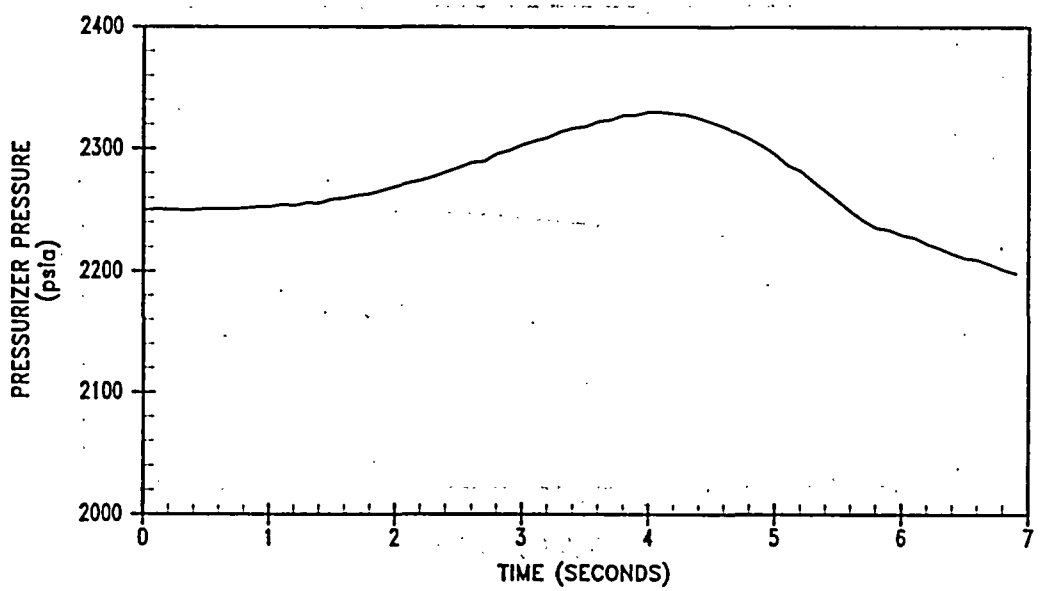


Figure 5.3.3-1A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power – 80 pcm/sec
Nuclear Power and Core Heat Flux versus Time



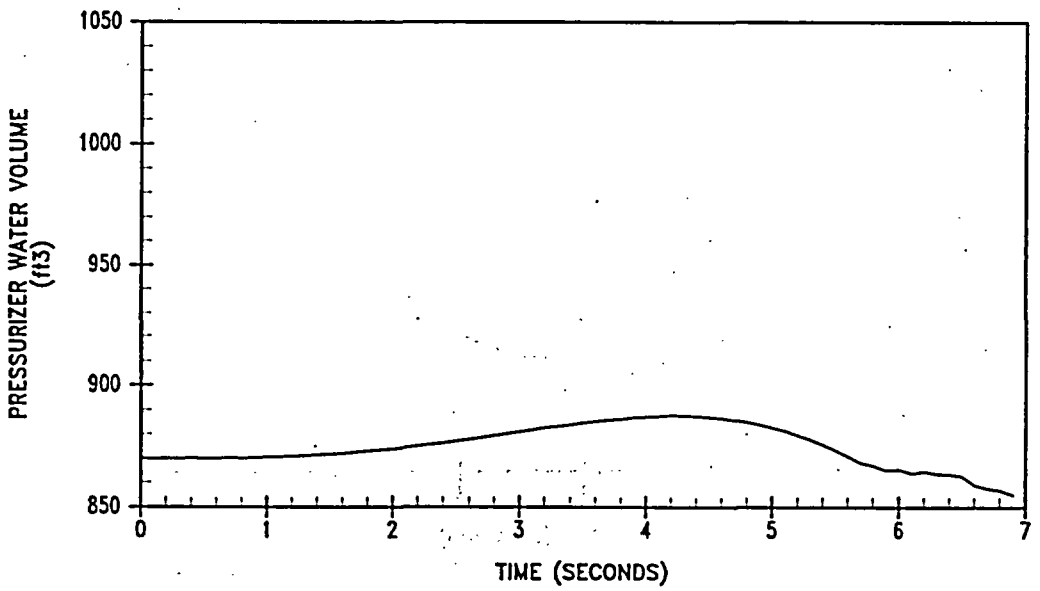
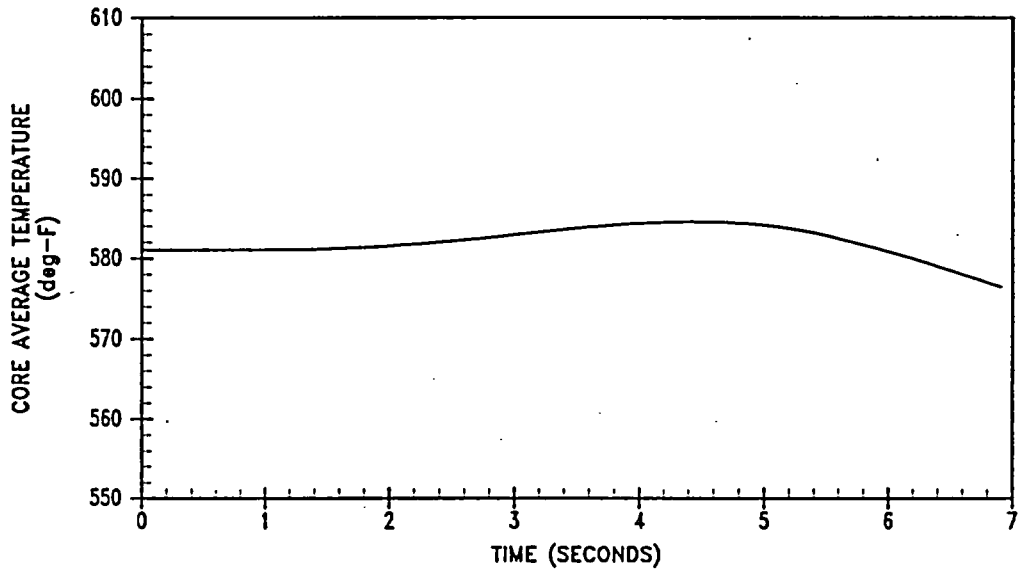


Figure 5.3.3-2A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power – 80 pcm/sec
Pressurizer Pressure and Water Volume versus Time



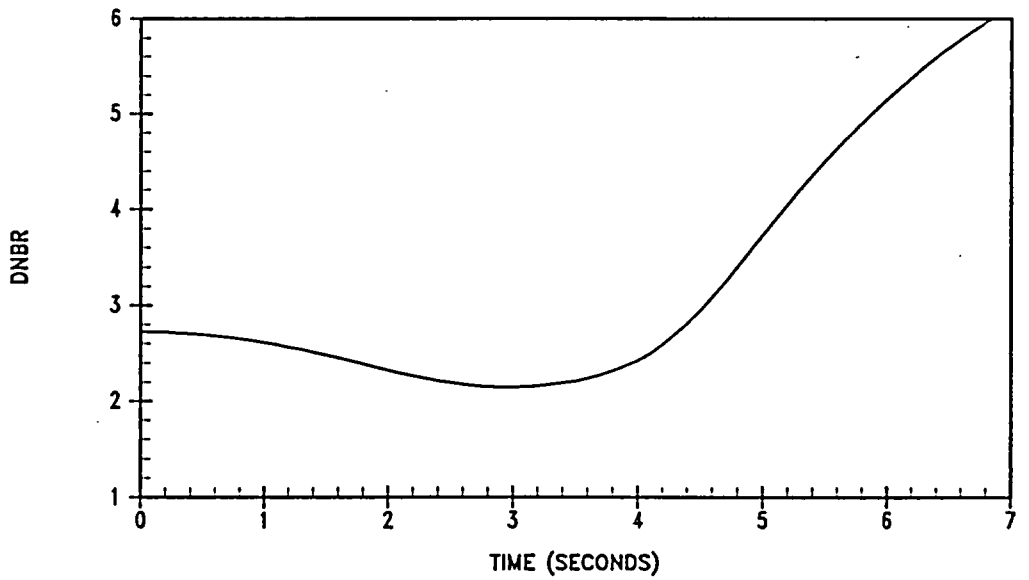
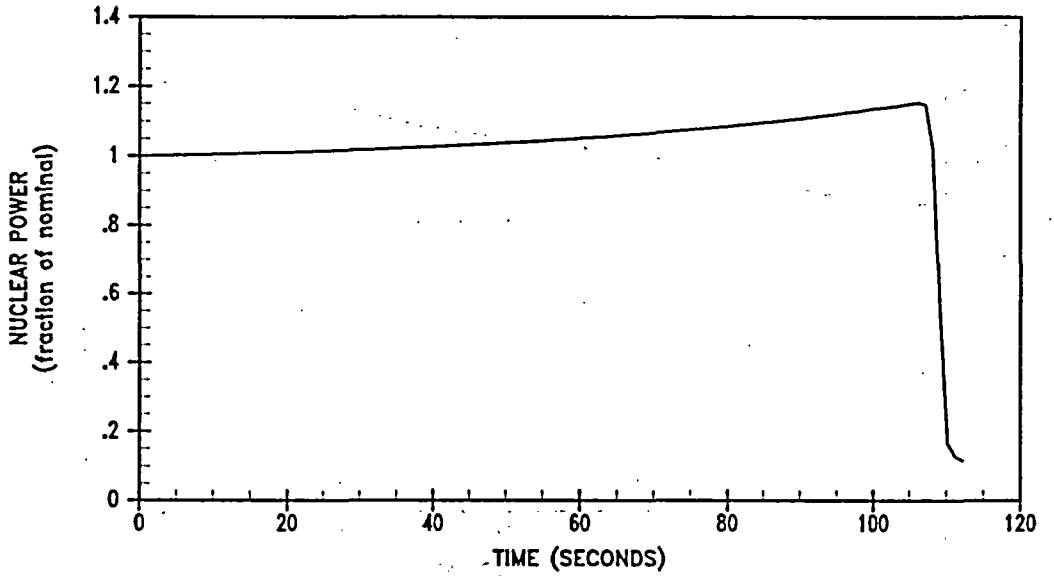


Figure 5.3.3-3A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power – 80 pcm/sec
Core Average Temperature and DNBR versus Time



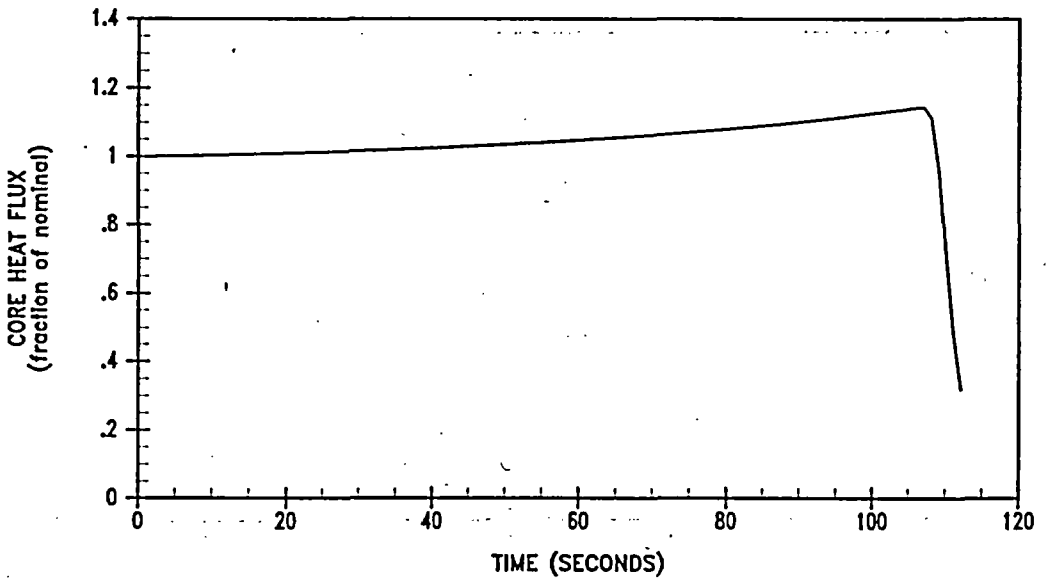
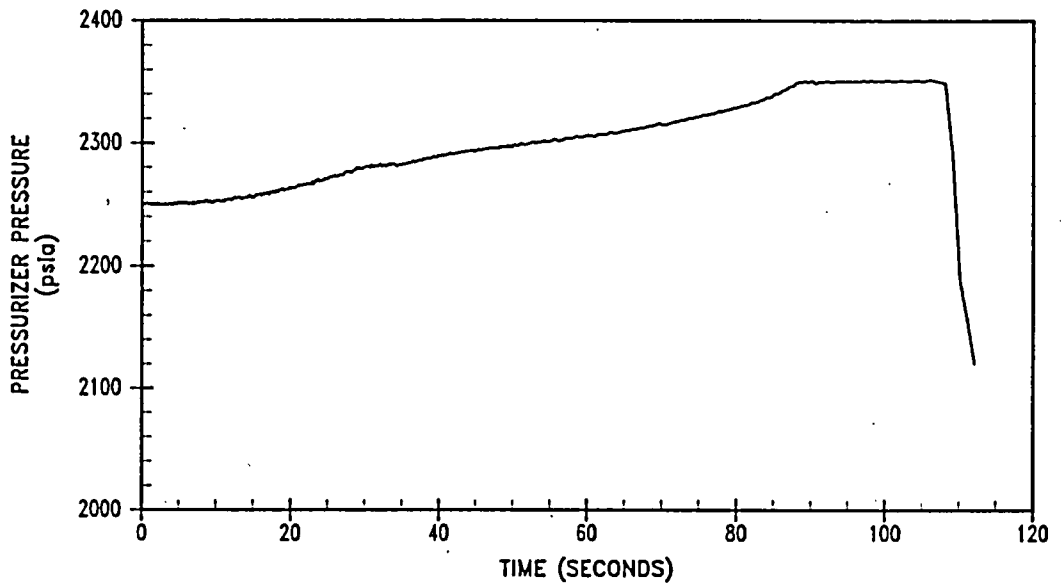


Figure 5.3.3-4A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power – 0.4 pcm/sec
Nuclear Power and Core Heat Flux versus Time



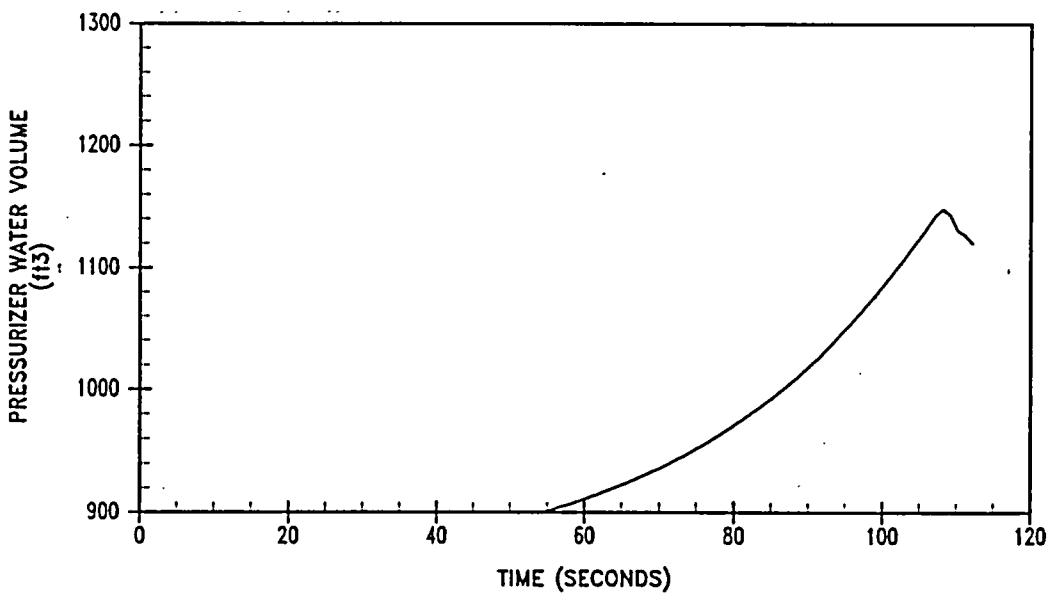
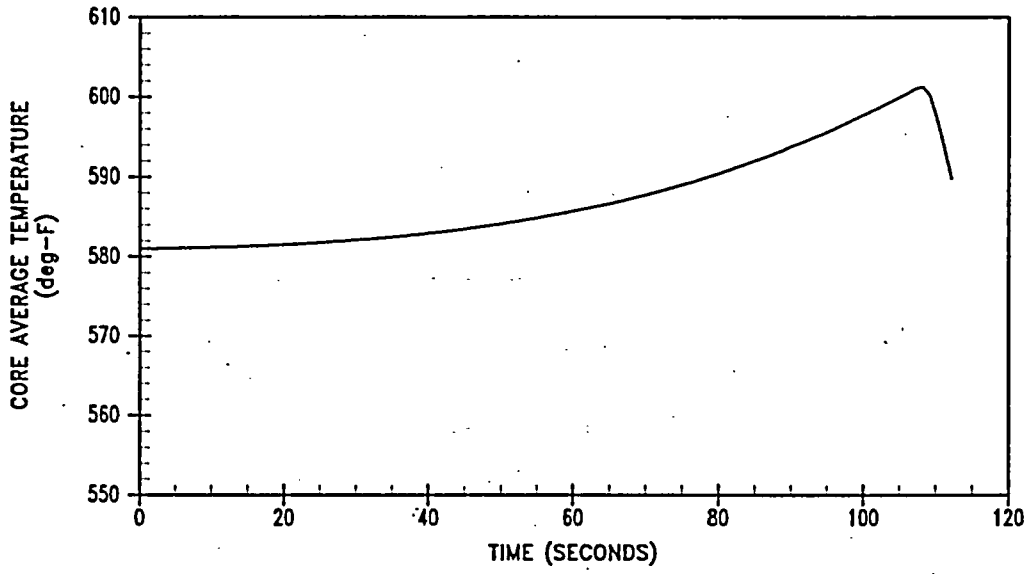


Figure 5.3.3-5A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power – 0.4 pcm/sec
Pressurizer Pressure and Water Volume versus Time



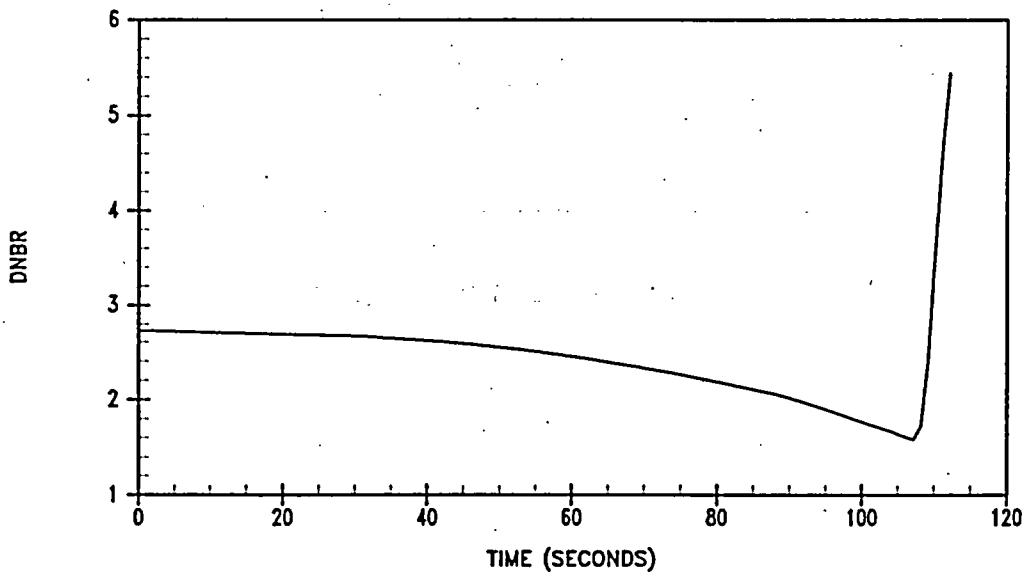


Figure 5.3.3-6A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power – 0.4 pcm/sec
Core Average Temperature and DNBR versus Time

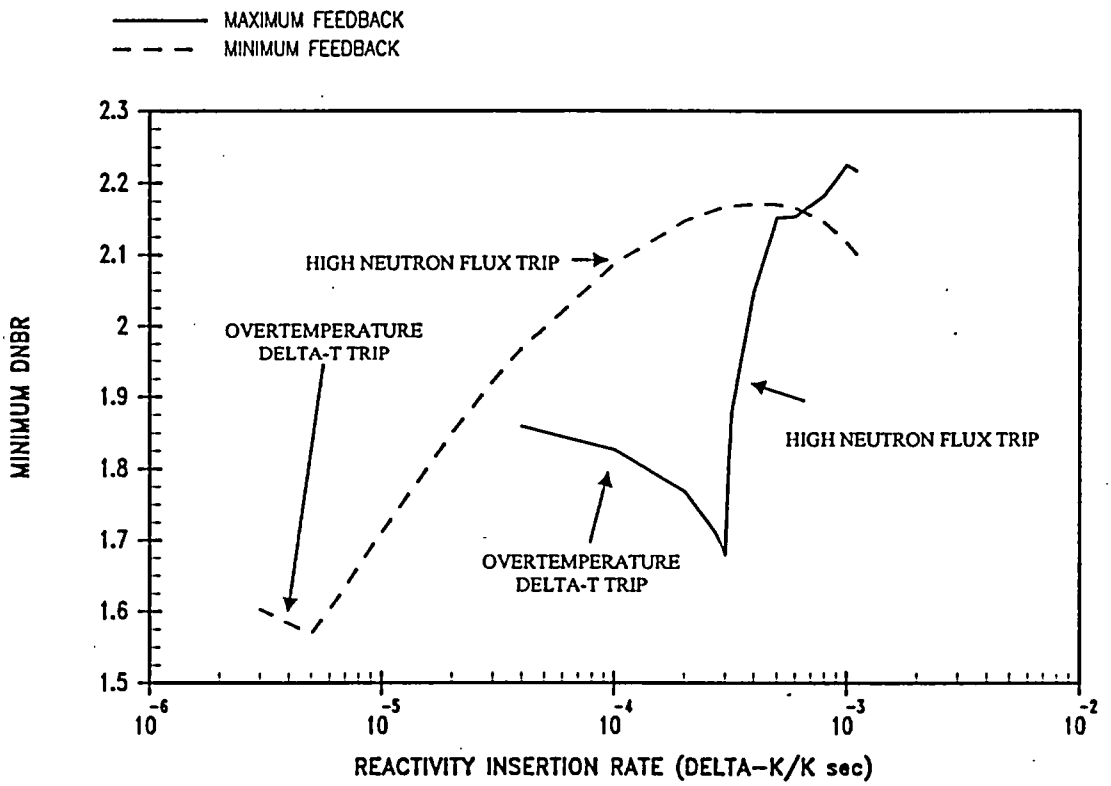


Figure 5.3.3-7A
BVPS-1 Rod Withdrawal at Power
100% Power
Minimum DNBR versus Reactivity Insertion Rate

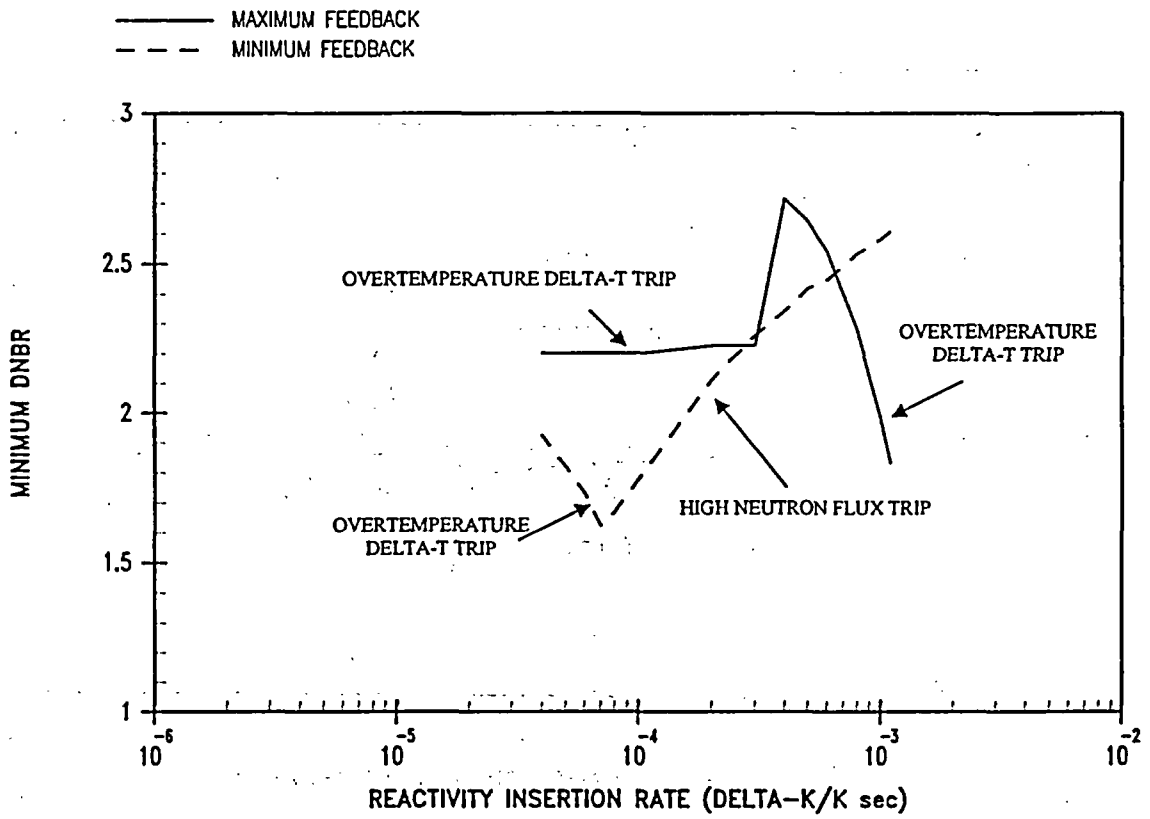


Figure 5.3.3-8A
BVPS-1 Rod Withdrawal at Power
60% Power
Minimum DNBR versus Reactivity Insertion Rate

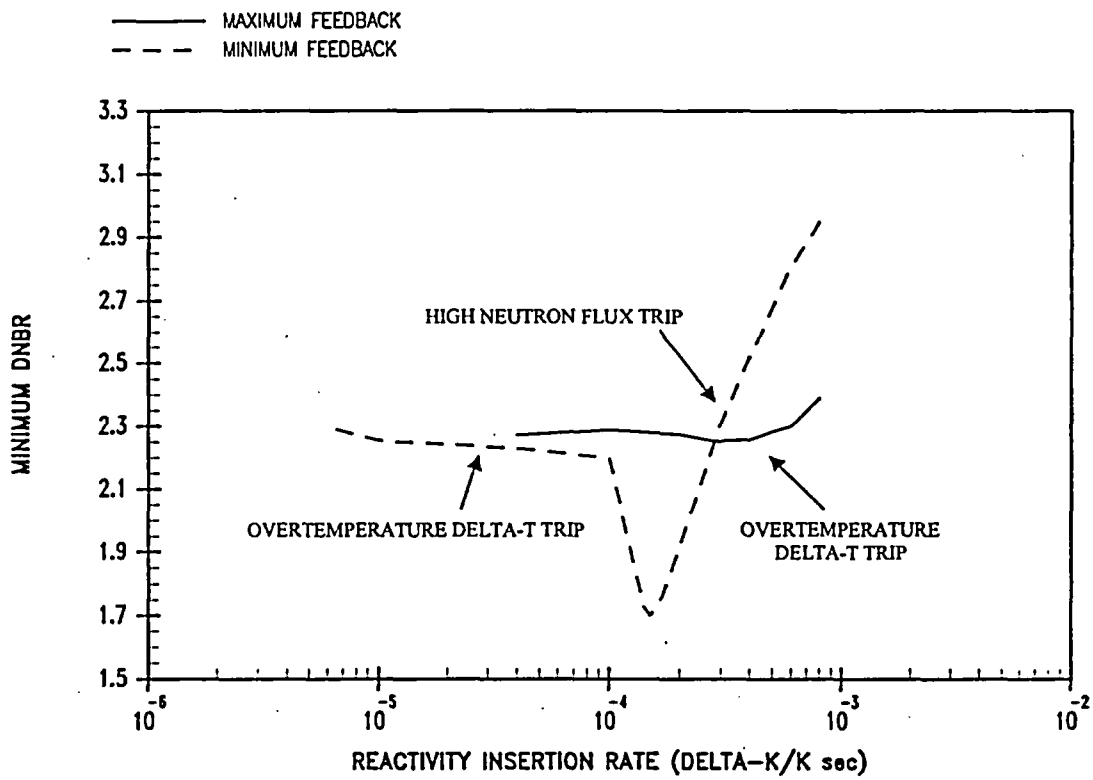


Figure 5.3.3-9A
BVPS-1 Rod Withdrawal at Power
10% Power
Minimum DNBR versus Reactivity Insertion Rate

5.3.4 RCCA Misalignment

5.3.4.1 Identification of Causes and Accident Description

The Rod Cluster Control Assembly (RCCA) Misalignment events include the following:

- One or more dropped RCCAs within the same group
- A dropped RCCA bank
- A statically misaligned RCCA

Each RCCA has a position indicator channel that displays the position of the assembly in a display grouping that is convenient to the operator. Fully inserted RCCAs are also indicated by a rod at bottom signal which actuates a control room annunciator. Group demand position is also indicated.

RCCAs move in preselected banks and the banks always move in the same preselected sequence. Each bank of RCCAs consists of two groups. The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation (or deactuation) of the stationary gripper, movable gripper, and lift coils of the control rod drive mechanism withdraws the RCCA held by the mechanism. Mechanical failures are in the direction of insertion or immobility.

A dropped RCCA, or RCCA bank is detected by one or more of the following:

- Sudden drop in the core power level as seen by the nuclear instrumentation system
- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples
- Rod at bottom signal
- Rod deviation alarm
- Rod position indication

Dropping of a full-length RCCA is assumed to be initiated by a single electrical or mechanical failure which causes any number and combination of rods from the same group of a given control bank to drop to the bottom of the core. The resulting negative reactivity insertion causes nuclear power to rapidly decrease. An increase in the hot channel factor may occur due to the skewed power distribution representative of a dropped rod configuration. For this event, it must be shown that the DNB design basis is met for the combination of power, hot channel factor, and other system conditions which exist following a dropped rod.

Misaligned assemblies are detected by:

- Asymmetric power distribution as seen on out of core neutron detectors or core exit thermocouples

- Rod deviation alarm
- Rod position indicators

For BVPS-1, the resolution of the rod position indicator channel is ±5% of span (±7.2 inches). Deviation of any assembly from its group by twice this distance (10% of span, or 14.4 inches) will not cause power distributions worse than the design limits. The deviation alarm alerts the operator to rod deviation with respect to group demand position in excess of 5% of span. If the rod deviation alarm is not operable, the operator is required to log the rod cluster control assembly positions in a prescribed time sequence to confirm alignment.

For BVPS-1, if one or more rod position indicator channels should be out of service, detailed operating instructions shall be followed to assure the alignment of the non-indicated RCCAs. The operator is also required to take action as required by the Technical Specifications.

5.3.4.2 Input Parameters and Assumptions

The RCCA Misalignment events are analyzed generically. The purpose of the generic analysis is to generate transient statepoints that are evaluated on a plant-specific cycle-specific basis during the reload process. The latest generic evaluation applicable is the evaluation that supported the control rod optimization program.

The statepoints are in the form of changes in key parameters from the initial values. These changes are applied to the actual plant specific conditions and evaluates the statepoints during each reload evaluation. The effect of a power increase on these generic statepoints has been previously addressed for other Westinghouse designed PWRs.

5.3.4.3 Description of the Analysis

The generic statepoints were evaluated and found to be applicable to the EPU. Those statepoints were evaluated using the VIPRE computer code (Reference 2) to support the DNB criteria and the fuel centerline melt criteria. A detailed discussion of the Westinghouse Dropped Rod Methodology is contained in Reference 3.

5.3.4.4 Acceptance Criteria and Results

Based on the frequency of occurrence, the RCCA Misalignment events are considered Condition II events as defined by the American Nuclear Society. The primary acceptance criterion for these events is that the critical heat flux should not be exceeded and that fuel centerline melt is precluded. This is demonstrated by showing that the Departure from Nucleate Boiling (DNB) design basis is met and that the peak kw/ft is below that which would cause fuel centerline melt.

The results of the evaluation for the RCCA Misalignment events show that the DNBR does not fall below the safety analysis limit value and that the peak kw/ft criteria is below that which causes fuel centerline melt.

5.3.4.5 Conclusions

Following a RCCA Misalignment event the plant will return to a stabilized condition. Results of the analysis show that a RCCA Misalignment event, with or without a reactor trip, does not adversely affect the core since the DNBR remains above the limit value for a range of dropped RCCA worths.

The DNBR limit is not violated; thus, there is no reduction in the ability of the primary coolant to remove heat from the fuel rod. The results also show that fuel centerline melting is precluded. After identifying a RCCA Misalignment condition, the operator must take action as required by the plant Technical Specifications and operating instructions.

The results and conclusions of the analysis performed for the RCCA misalignment for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt. Furthermore, the results and conclusions of this analysis will be confirmed on a cycle specific basis as part of the normal reload process.

5.3.4.6 References

1. Friedland, A. J., and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), April 1989.

2. Sung, Y. X. et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), October 1999.

3. Haessler, R. L., et al., "Methodology for the Analysis of the Dropped Rod Event," WCAP-11394 (Proprietary) and WCAP-11395 (Non-Proprietary), April 1987.

5.3.5 Uncontrolled Boron Dilution

5.3.5.1 Identification of Causes and Accident Description

Reactivity can be added to the core by feeding primary grade water into the Reactor Coolant System (RCS) via the reactor makeup portion of the Chemical and Volume Control System (CVCS). Boron dilution is a manual operation under strict administrative controls with procedures calling for a limit on the rate and duration of dilution. A boric acid blend system is provided to permit the operator to match the boron concentration of reactor coolant makeup water during normal charging to the RCS boron concentration. As discussed below, the CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value which, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

5.3.5.2 Input Parameters and Assumptions

The opening of the primary water makeup control valves provides makeup to the CVCS and subsequently to the RCS which can dilute the reactor coolant. Inadvertent dilution from this source can be readily

terminated by closing the control valve. In order for makeup water to be added to the RCS at pressure, at least one charging pump must be running in addition to a primary makeup water pump.

There is only a single line connecting the primary grade water header to the CVCS and inadvertent dilution can be readily terminated by isolating this line. The primary grade water header can be supplied by either the primary grade water pumps or from a cross connection to the turbine plant demineralized water system. The maximum dilution flow is 231 gpm, based on operation of a primary grade water pump in addition to a charging pump if the RCS is at pressure.

The boric acid from the boric acid tank is blended with primary grade water in the blender and the composition is determined by the preset flow rates of boric acid and primary grade water on the control board. In order to dilute, two separate operations are required. The operator must switch from the automatic makeup mode to the dilute or alternate dilute mode, and the start switch must be placed in the start position. Omitting either step would prevent dilution.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of the pumps in the CVCS. Alarms are actuated to warn the operator if boric acid or makeup water flow rates deviate from preset values as a result of system malfunction.

5.3.5.3 Description of Analysis

5.3.5.3.1 Dilution During Modes 4, 5, and 6

An uncontrolled boron dilution transient cannot occur during these modes of operation. The primary means for a significant boron dilution is through the injection of unborated water into the Reactor Coolant System. Inadvertent boron dilution is prevented by administrative controls which isolate the primary grade water system isolation valves from the Chemical and Volume Control System, except during planned boron dilution or makeup activities. Thus unborated water cannot be injected into the Reactor Coolant System inadvertently, making an unplanned boron dilution at these conditions highly improbable, because the source of unborated water to the charging pumps is isolated and the low head safety injection pumps cannot be aligned to the primary grade water supply. This precludes the primary means for an inadvertent boron dilution event in these modes of operation.

5.3.5.3.2 Dilution During Mode 3

The analysis of the boron dilution event during Mode 3 assumes a maximum dilution flow rate of 231 gpm. An active RCS volume of 6964 ft^3 is assumed for BVPS-1. From the initiation of the event, there is greater than 15 minutes available for operator action prior to return to criticality.

5.3.5.3.3 Dilution During Mode 2

In this mode, the plant is being taken from one long-term mode of operation (Mode 3) to another (Mode 1). Typically, the plant is maintained in the startup mode only for the purpose of startup testing at the beginning of each cycle. All normal actions required to change power level, either up or down, require operator initiation.

The analysis of the boron dilution event in Mode 2 assumes a maximum dilution flow rate of 231 gpm. An active RCS volume of 7593 ft^3 is assumed for BVPS-1.

Mode 2 is a transitory operational mode in which the operator intentionally dilutes and withdraws control rods to achieve criticality. During this mode, the rods are in manual control with the operator required to maintain a high awareness of the plant status. For a normal approach to criticality, the operator must manually initiate a limited dilution and subsequently manually withdraw the control rods. The operator determines the estimated critical position of the control rods prior to approaching criticality, thus ensuring that the reactor does not go critical with the control rods below the insertion limits. Once critical, the power escalation must be sufficiently slow to allow the operator to manually block the source range reactor trip (nominally at 10^5 cps) after receiving P-6 from the intermediate range. Too fast of a power escalation (due to an unknown dilution) would result in reaching P-6 unexpectedly, leaving insufficient time to manually block the source range reactor trip, and the reactor would immediately shut down.

However, in the event of an unplanned approach to criticality or dilution during power escalation while in Mode 2, the plant status is such that minimal impact will result. The plant will slowly escalate in power until the power range high neutron flux trip setpoint is reached and a reactor trip occurs. From the initiation of the event, there is greater than 15 minutes available for operator action prior to return to criticality.

5.3.5.3.4 Dilution During Mode 1

In this mode, the plant may be operated in either automatic or manual rod control. The analysis assumes a maximum dilution flow rate of 231 gpm. An active RCS volume of 7593 ft^3 is assumed for BVPS-1.

With the reactor in automatic rod control the power and temperature increase from the boron dilution results in insertion of the control rods and a decrease in available shutdown margin. The rod insertion limit alarms (Low and Low-Low settings) alert the operator at least 15 minutes prior to criticality. This is sufficient time to determine the cause of dilution and isolate the reactor makeup water source before the available shutdown margin is lost.

With the reactor in manual control and no operator action taken to terminate the transient, the power and temperature rise will cause the reactor to reach the power range high neutron flux trip setpoint for BVPS-1, resulting in a reactor trip. The boron dilution transient in this case is essentially equivalent to an uncontrolled RCCA bank withdrawal at power. The maximum reactivity insertion rate for a boron dilution is conservatively estimated to be 2.8 pcm/sec, which is within the range of insertion rates analyzed. Thus, the effects of dilution prior to reactor trip are bounded by the uncontrolled RCCA bank withdrawal at power analysis (Section 5.3.3 of this report). Following reactor trip, there is greater than 15 minutes prior to criticality. This is sufficient time for the operator to determine the cause of dilution and isolate the reactor makeup water source before the available shutdown margin is lost.

5.3.5.4 Acceptance Criteria and Results

A CVCS malfunction is classified as an ANS Condition II event, a fault of moderate frequency. Criteria established for Condition II events are as follows:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the reactor coolant and main steam systems should be maintained below 110% of the design pressures.
- Fuel temperature and fuel clad strain limits should not be exceeded. The peak linear heat generation rate should not exceed a value that would cause fuel centerline melt.

This event is analyzed to show that there is sufficient time for mitigation of an inadvertent boron dilution prior to the complete loss of shutdown margin. A complete loss of plant shutdown margin results in a return of the core to the critical condition causing an increase in the RCS temperature and heat flux. This could violate the safety analysis limit DNBR value and challenge the fuel and fuel cladding integrity. A complete loss of plant shutdown margin could also result in a return of the core to the critical condition causing an increase in RCS pressure. This could challenge the pressure design limit for the reactor coolant system.

If the minimum allowable shutdown margin is shown not to be lost, the condition of the plant at any point in the transient is within the bounds of those calculated for other Condition II transients. By showing that the above criteria are met for those Condition II events, it can be concluded that they are also met for the boron dilution event. Operator action is relied upon to preclude a complete loss of plant shutdown margin.

The Boron Dilution analysis demonstrates that all applicable acceptance criteria are met. This means that operator action to terminate the dilution flow within 15 minutes from event initiation from Mode 1, Mode 2 or Mode 3 will preclude a complete loss of shutdown margin. The results of the Boron Dilution analysis are as follows.

Boron Dilution	BVPS-1	BVPS-2
Mode 1 – Manual Rod Control	30.4 minutes	NA
Mode 1 – Automatic Rod Control	31.7 minutes	NA
Mode 2	33.3 minutes	NA
Mode 3	15.3 minutes	NA

5.3.5.5 Conclusions

If an unintentional dilution of boron in the reactor coolant system does occur, numerous alarms and indications are available to alert the operator to the condition. The maximum reactivity addition due to the dilution is slow enough to allow the operator sufficient time to determine the cause of the addition and

take corrective action before shutdown margin is lost. The acceptance criteria as specified in Section 5.3.5.4 are met.

The results and conclusions of the analysis performed for the uncontrolled boron dilution for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

5.3.6 Loss of External Electrical Load and/or Turbine Trip

5.3.6.1 Identification of Causes and Accident Description

A major load loss on the plant can result from either a loss of external electrical load or from a turbine trip. A loss of external electrical load may result from an abnormal variation in network frequency or other adverse network operating condition. For either case, offsite power is available for the continued operation of plant components such as the reactor coolant pumps. The case of loss of all non-emergency AC power is evaluated in Section 5.3.8.

For a loss of external electrical load without subsequent turbine trip, no direct reactor trip signal would be generated. The station is designed to accept a significant loss of load without actuating a reactor trip with all NSSS control systems in automatic (reactor control system, pressurizer pressure and level, steam generator water level control, and steam dumps). The automatic steam dump system together with the rod control system is able to accommodate the load rejection. Reactor power is reduced to a new equilibrium value consistent with the capability of the rod control system.

For a turbine trip event, the reactor would be tripped directly (unless below P-9) by a signal derived from the turbine auto-stop oil pressure and turbine stop valves. The turbine stop valves close rapidly on loss of trip-fluid pressure actuated by one of a number of turbine trip signals. Reactor coolant temperatures and pressure do not significantly increase if the steam dump and pressurizer pressure control systems are functioning properly.

In the event the steam dump valves fail to open following a large loss of load, the steam generator safety valves may lift and the reactor may be tripped by the high pressurizer pressure signal, the high pressurizer water level signal or the overtemperature ΔT signal. In the event of feedwater flow also being lost, the reactor may also be tripped by a steam generator low-low water level signal. The steam generator shell-side pressure and reactor coolant temperatures will increase rapidly. The pressurizer safety valves and steam generator safety valves are sized to protect the RCS and steam generator against overpressure for all load losses without assuming the operation of the steam dump system, pressurizer spray, pressurizer power-operated relief valves, automatic rod control, or the direct reactor trip on turbine trip.

The pressurizer safety valve capacity is sized based on a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load along with operation of the steam generator safety valves. The pressurizer and steam generator safety valves are then able to maintain the RCS and Main Steam System pressures within 110% of the corresponding design pressure without a direct reactor trip on turbine trip.

The Reactor Trip System in conjunction with the primary and secondary system designs preclude overpressurization without requiring the automatic rod control, pressurizer pressure control and/or turbine bypass control system (i.e., steam dumps).

5.3.6.2 Input Parameters and Assumptions

Two cases are analyzed for a total loss of load from full power conditions: a) minimum reactivity feedback with pressure control; and b) minimum reactivity feedback without pressure control. The primary concern for the case analyzed with pressure control is the minimum departure from nucleate boiling ratio (DNBR); the primary concern for the case analyzed without pressure control is maintaining reactor coolant system pressure below 110% of the design pressure.

The major assumptions used in the analyses are summarized in the following.

Initial Operating Conditions

The case with pressure control is analyzed using the Revised Thermal Design Procedure (Reference 1). Initial core power, RCS temperature and RCS pressure are assumed to be at their nominal values, adjusted to account for any applicable measurement biases, consistent with steady-state full power operation. Minimum Measured Flow is modeled. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 1.

The case without pressure control is analyzed using the Standard Thermal Design Procedure (STDP). Initial uncertainties on core power, reactor coolant temperature, and pressure are applied in the conservative direction to obtain the initial plant conditions for the transient. The analysis models Thermal Design Flow.

The nominal NSSS full power is 2910 MWt. Thus, as is discussed above, the RTDP case is initialized at 2910 MWt and the STDP case is initialized at 2927.5 MWt (2910*1.006).

Reactivity Coefficients

The total loss of load transient is conservatively analyzed with minimum reactivity feedback (BOL). Both cases for BVPS-1 assume the least-negative Doppler coefficient and a 0 pcm/°F moderator temperature coefficient, which bounds part power conditions assuming a positive moderator temperature coefficient.

Reactor Control

From the standpoint of the maximum pressures attained, it is conservative to assume that the reactor is in manual rod control. If the reactor were in automatic rod control, the control rod banks would move prior to trip and reduce the severity of the transient.

Pressurizer Spray, Power-Operated Relief Valves and Safety Valves

The loss of load event is analyzed both with and without pressurizer pressure control. The pressurizer PORVs and sprays are assumed operable for the case with pressure control. The case with pressure control minimizes the increase in primary pressure, which is conservative for the DNBR criterion. The case without pressure control maximizes the pressure increase, which is conservative for the RCS overpressurization criterion. In all cases, the steam generator and pressurizer safety valves are operable.

The pressurizer safety valves are modeled including the effects of the pressurizer safety valve loop seals using the WOG methodology described in Reference 3. A total pressurizer safety valve setpoint tolerance of ±3% for BVPS-1 is supported in the analysis. For the case which is analyzed for DNBR (pressurizer pressure control case), the negative tolerance is applied to conservatively reduce the setpoint. (The pressurizer safety valves do not actuate for the case being reported.) For the case analyzed for peak RCS pressure, the positive tolerance is applied to conservatively increase the setpoint pressure. An additional +1% uncertainty to account for the setpoint shift as described in Reference 3 is not applicable for BVPS-1. In the peak RCS pressure case, opening of the pressurizer safety valves is delayed by a time assumed to cover the time to purge the loop seals and the valve stroke time for BVPS-1 (1.05 seconds).

Feedwater Flow

Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater flow; however, eventually auxiliary feedwater flow would be initiated and a stabilized plant condition would be reached.

Reactor Trip

Only the overtemperature ΔT, high pressurizer pressure, and low-low steam generator water level reactor trips are assumed operable for the purposes of this analysis. No credit is taken for a reactor trip on high pressurizer level or the direct reactor trip on turbine trip.

Steam Release

No credit is taken for the operation of the steam dump system or steam generator atmospheric relief valves. This assumption maximizes secondary pressure. The main steam safety valve model includes an allowance of +3% for safety valve setpoint tolerance and an accumulation model that assumes that the safety valves are wide open once the pressure exceeds the setpoint (plus tolerance) by 5 psi.

5.3.6.3 Description of Analyses

For the Loss of External Electrical Load/Turbine Trip Event, the behavior of the unit is analyzed for a complete loss of steam load from full power without a direct reactor trip. This assumption is made to show the adequacy of the pressure-relieving devices and to demonstrate core protection margins, by delaying reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis assumes a worst-case transient. This analysis demonstrates that at-power overpressure protection is provided for both the primary and secondary systems.

A detailed analysis using the LOFTRAN (Reference 2) computer code is performed to determine the plant transient conditions following a total loss of load. The code models the core neutron kinetics, RCS including natural circulation, pressurizer, pressurizer PORVs and sprays, steam generators, main steam safety valves, and the auxiliary feedwater system; and computes pertinent variables, including the pressurizer pressure, steam generator pressure, steam generator mass, and reactor coolant average temperature.

5.3.6.4 Acceptance Criteria and Results

Based on its frequency of occurrence, the Loss of External Electrical Load/Turbine Trip accident is considered a Condition II event as defined by the American Nuclear Society. The specific criteria for this accident, as stated in the Standard Review Plan, are as follows:

- Pressure in the reactor coolant and main steam systems should be maintained below 110% of the design values (an RCS pressure limit of 2748.5 psia and secondary side pressure limit of 1208.5 psia).

- Fuel cladding integrity shall be maintained by demonstrating that the minimum DNBR remains above the 95/95 DNBR limit for PWRs (the applicable safety analysis DNBR limit is 1.55).

- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently.

  This criterion is satisfied by verifying that the pressurizer does not fill.

- An incident of moderate frequency in combination with any single active component failure, or single operator error, shall be considered an event for which an estimate of the number of potential fuel failures shall be provided for radiological dose calculations. For such accidents, fuel failure must be assumed for all rods for which the DNBR falls below those values cited above for cladding integrity unless it can be shown, based on an acceptable fuel damage model, that fewer failures occur. There shall be no loss of function of any fission product barrier other than the fuel cladding.

  This criterion is satisfied by verifying that DNBR remains above the 95/95 DNBR limit.

The calculated sequence of events for the two Loss of External Electrical Load/Turbine Trip cases are presented in Table 5.3.6-1A.

Case 1: With Pressure Control

The transient response for the total loss of load event under BOL conditions with pressure control is shown in Figures 5.3.6-1A through 5.3.6-4A for BVPS-1.

For BVPS-1, the reactor is tripped via an overtemperature ΔT signal. The neutron flux decreases slowly until the reactor is tripped, and although the DNBR value decreases below the initial value, it remains well above the safety analysis limit throughout the entire transient. The pressurizer power-operated relief

valves and sprays maintain primary pressure below 110% of the design value. The main steam safety valves are also actuated and maintain secondary pressure below 110% of the design value. The peak pressurizer water volume remains below the total volume of the pressurizer, demonstrating that this event does not generate a more serious plant condition.

Case 2: Without Pressure Control

The transient response for the total loss of load event under BOL conditions without pressure control is shown in Figures 5.3.6-5A through 5.3.6-8A for BVPS-1.

For BVPS-1, the reactor is tripped on high pressurizer pressure. The neutron flux remains essentially constant at full power until the reactor is tripped. The pressurizer safety valves are actuated and maintain primary pressure below 110% of the design value. The main steam safety valves are also actuated and maintain secondary pressure below 110% of the design value. The peak pressurizer water volume remains below the total volume of the pressurizer, demonstrating that this event does not generate a more serious plant condition.

5.3.6.5 Conclusions

The results of this analysis show that the plant design is such that a total loss of external electrical load without a direct reactor trip presents no hazard to the integrity of the RCS or the main steam system. All of the applicable acceptance criteria are met. The minimum DNBR for each case is greater than the applicable safety analysis limit value. The peak primary and secondary system pressures remain below 110% of design at all times. The protection features presented in Section 5.3.6.2 provide mitigation of the Loss of External Electrical Load/Turbine Trip transient such that the above criteria are satisfied.

The results and conclusions of the analysis performed for the loss of external load and/or turbine trip for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

5.3.6.6 References

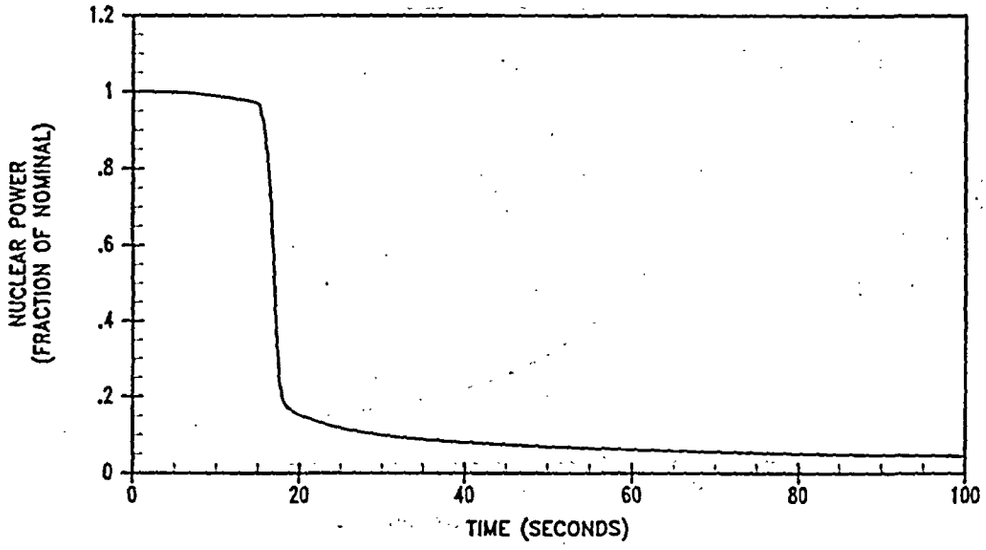
1. Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), April 1989.

2. Burnett, T.W.T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.

3. Barrett, G. O., et al., "Pressurizer Safety Valve Set Pressure Shift," WCAP-12910, Rev 1-A (Proprietary), May 1993.

Table 5.3.6-1A
BVPS-1 Time Sequence of Events – Loss of External Electrical Load and/or Turbine Trip

Case	Event	Time (Sec)
With pressurizer pressure control (minimum reactivity feedback-DNB Case)	Loss of Electrical Load/Turbine Trip	0.0
	Overtemperature ΔT Reactor Trip Setpoint reached	12.3
	Rods begin to drop	14.3
	Minimum DNBR occurs	15.6
Without pressurizer pressure control (minimum reactivity feedback-Pressure Case)	Loss of Electrical Load/Turbine Trip	0.0
	High Pressurizer Pressure Reactor Trip Setpoint reached	5.5
	Rods begin to drop	7.5
	Peak pressurizer pressure occurs	8.2



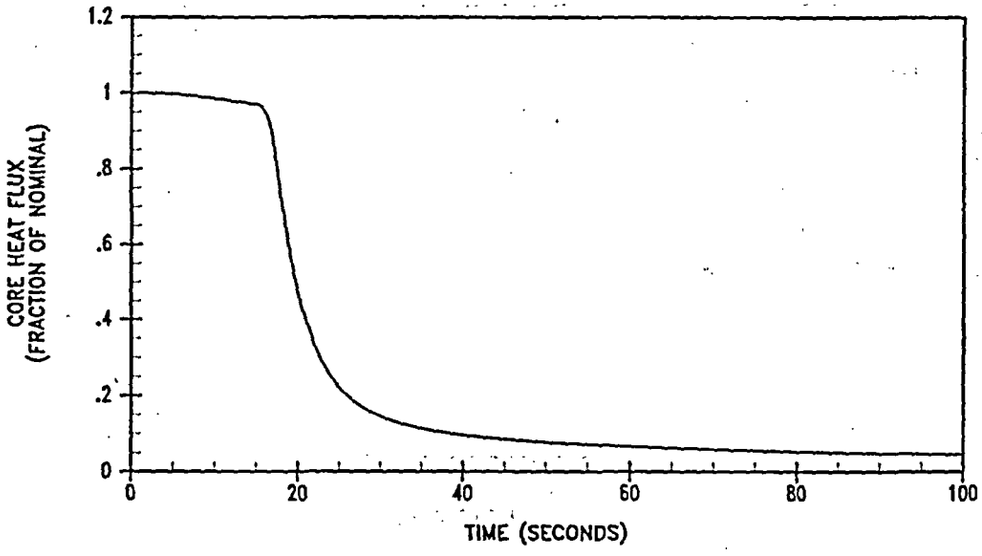
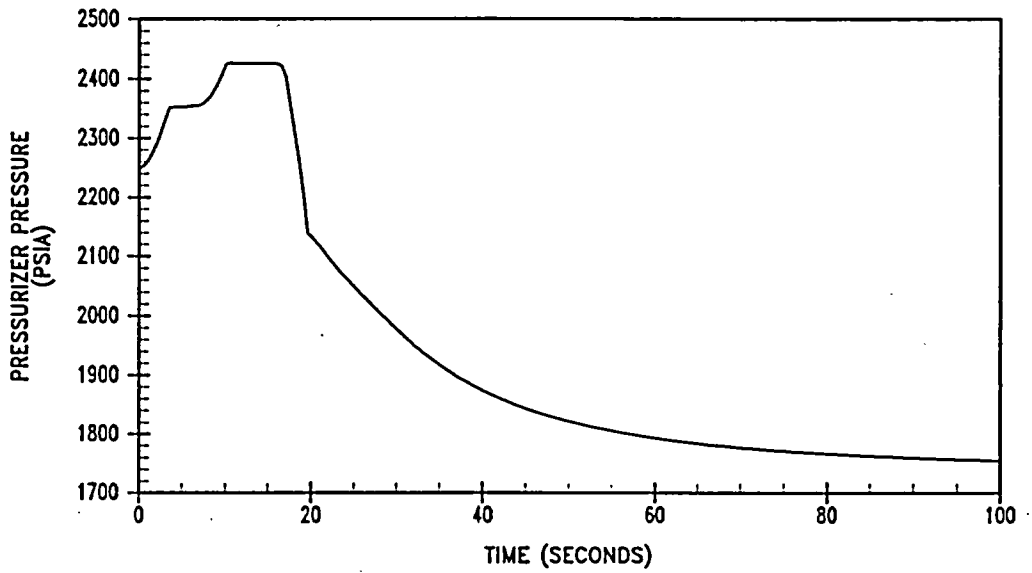


Figure 5.3.6-1A
BVPS-1 Loss of Load/Turbine Trip with Pressure Control
Nuclear Power and Core Heat Flux versus Time



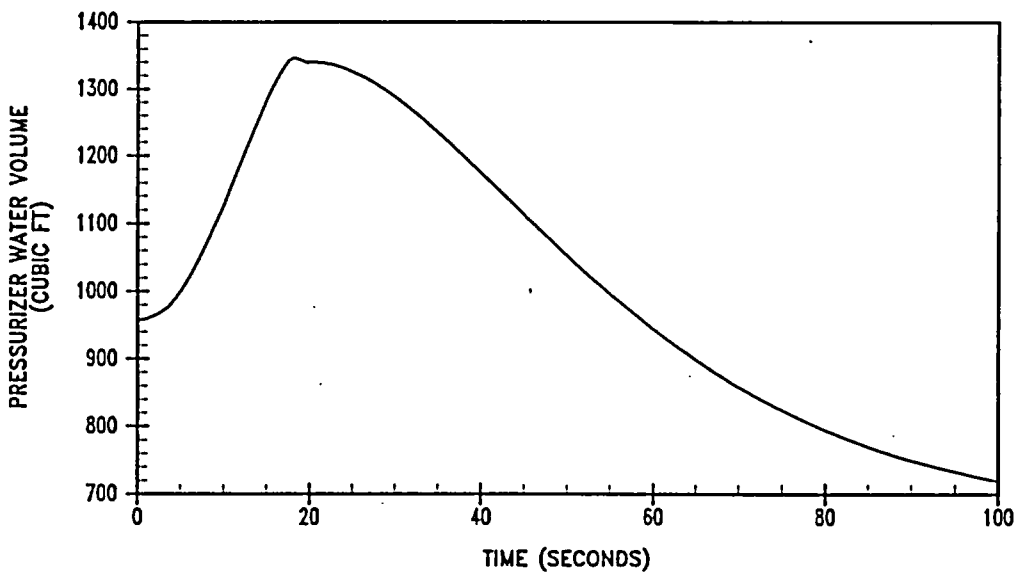
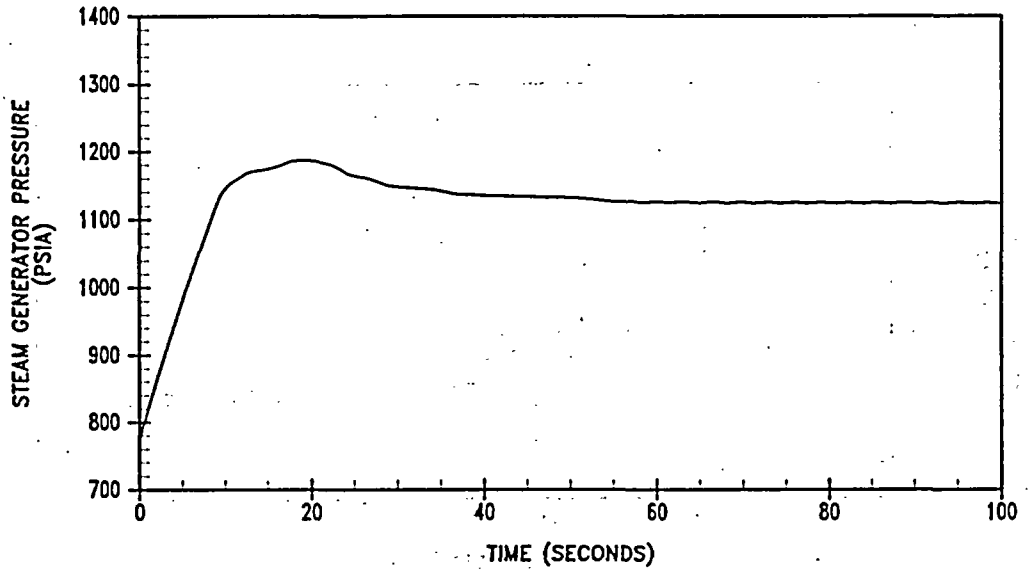


Figure 5.3.6-2A
BVPS-1 Loss of Load/Turbine Trip with Pressure Control
Pressurizer Pressure and Water Volume versus Time



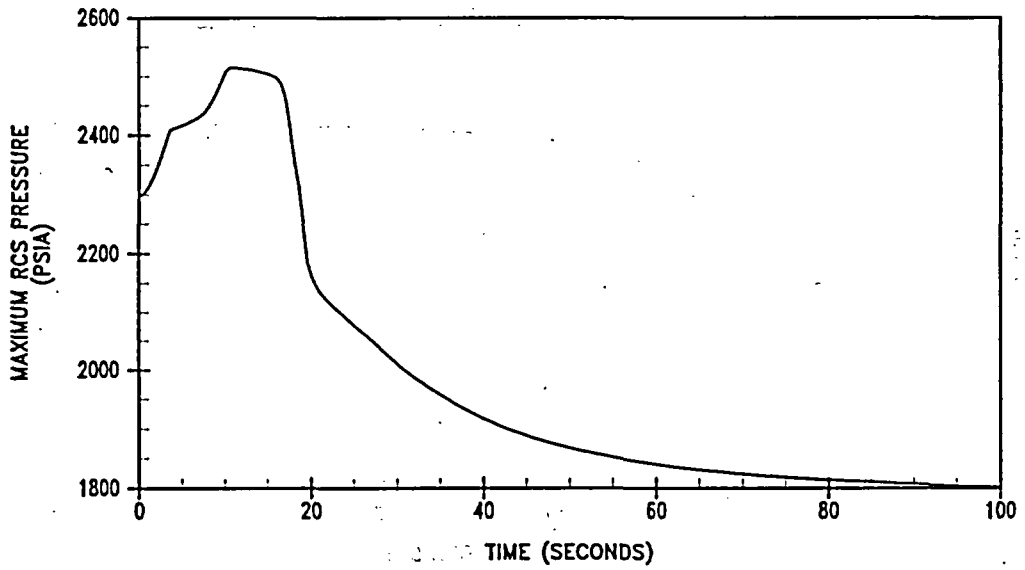


Figure 5.3.6-3A
BVPS-1 Loss of Load/Turbine Trip with Pressure Control
Steam Generator Pressure and Maximum RCS Pressure versus Time

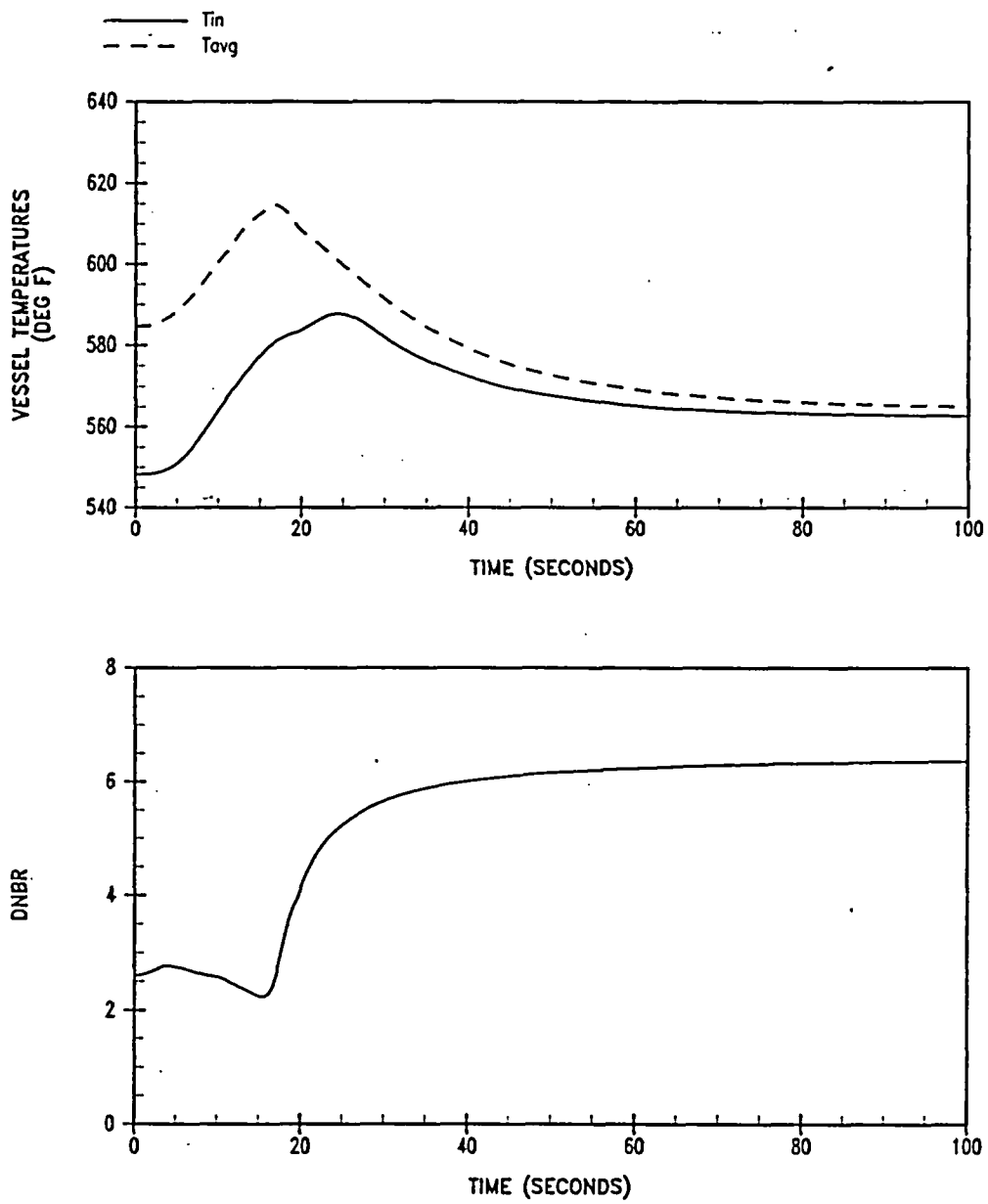
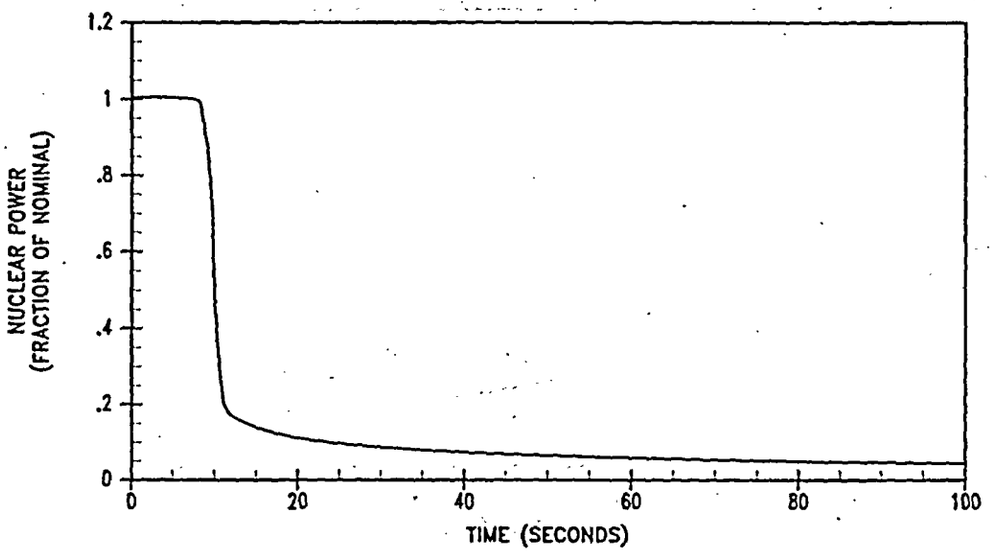


Figure 5.3.6-4A
BVPS-1 Loss of Load/Turbine Trip with Pressure Control
RCS Coolant Temperatures and DNBR versus Time



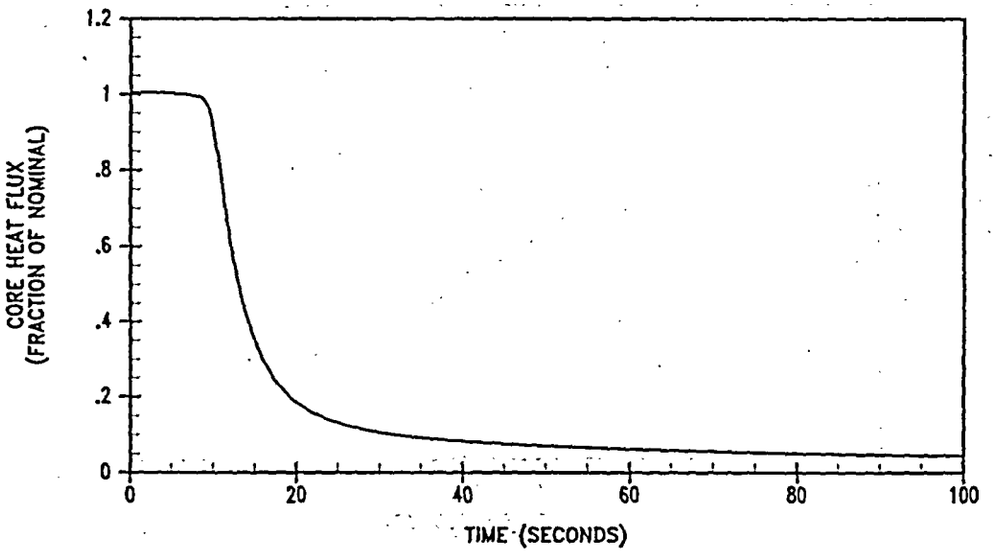
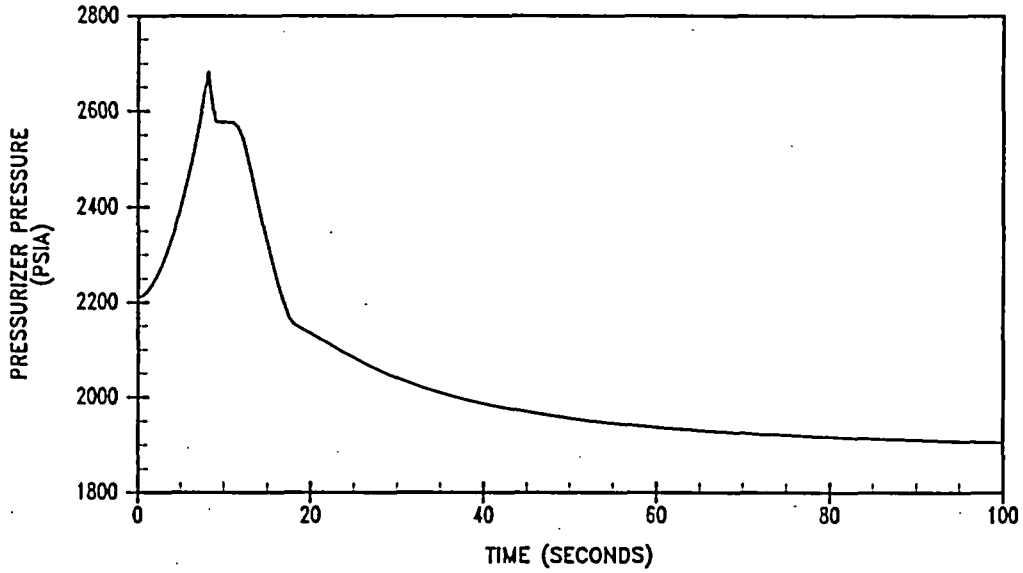


Figure 5.3.6-5A
BVPS-1 Loss of Load/Turbine Trip without Pressure Control
Nuclear Power and Core Heat Flux versus Time



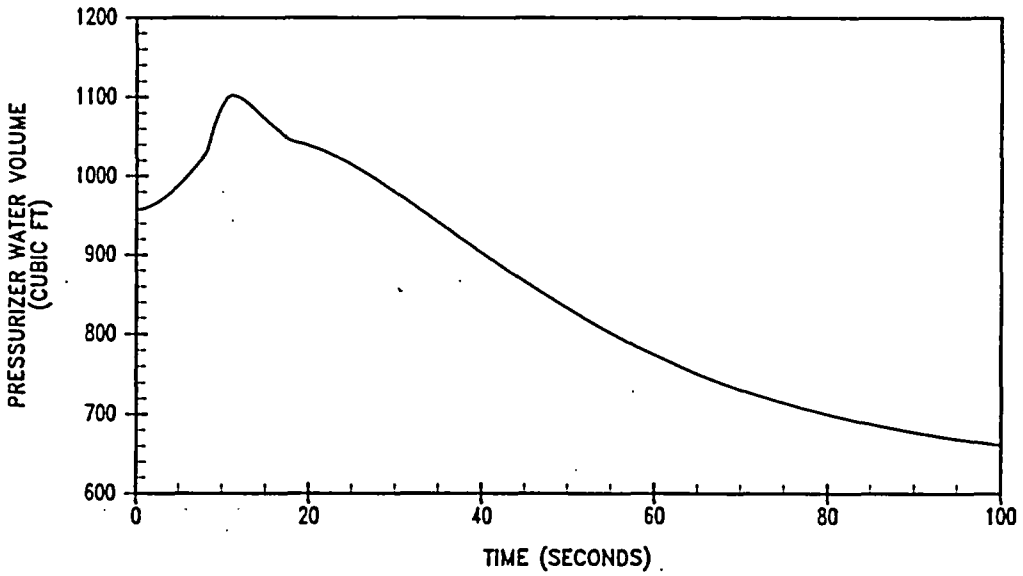
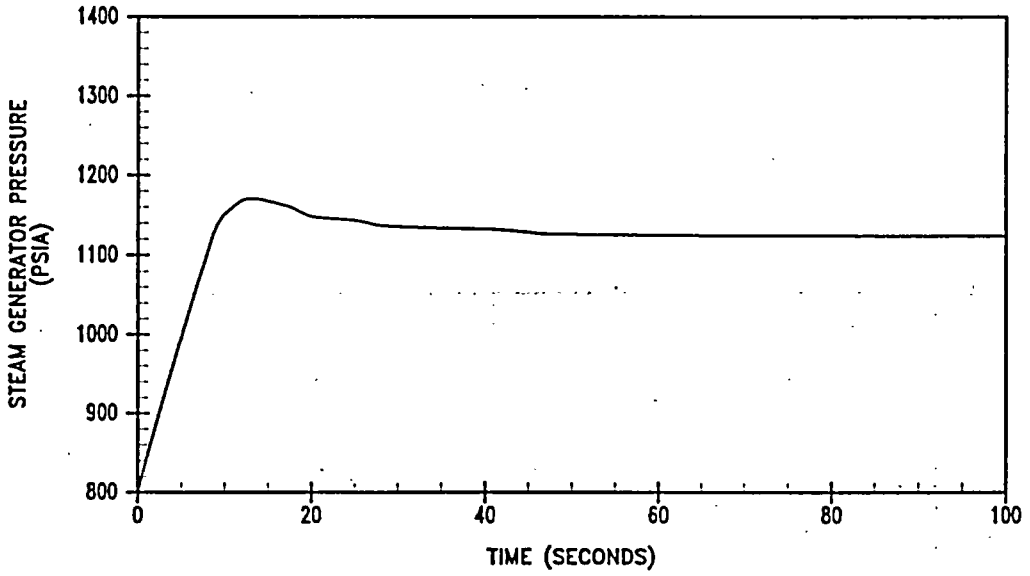


Figure 5.3.6-6A
BVPS-1 Loss of Load/Turbine Trip without Pressure Control
Pressurizer Pressure and Water Volume versus Time



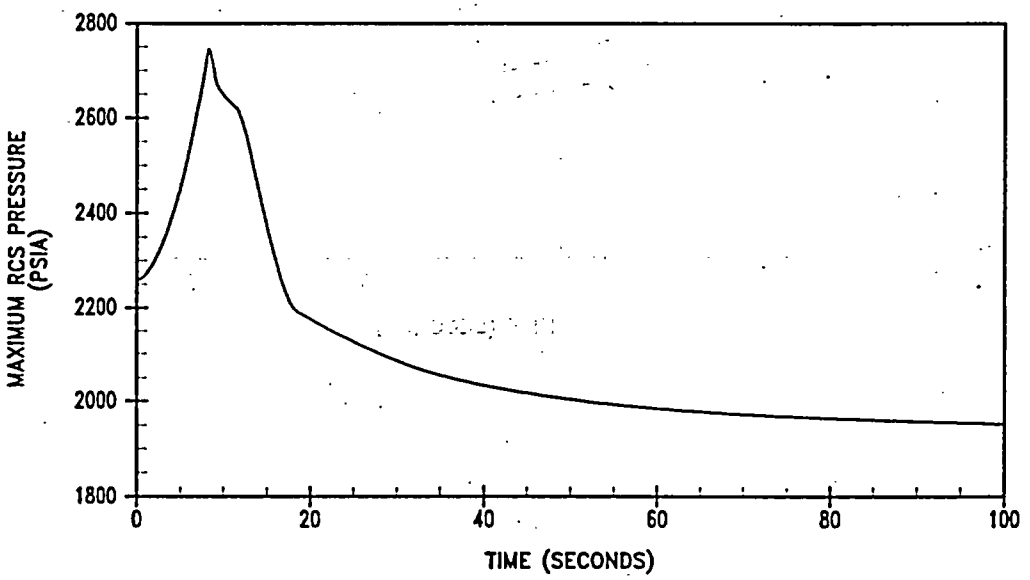


Figure 5.3.6-7A
BVPS-1 Loss of Load/Turbine Trip without Pressure Control
Steam Generator Pressure and Maximum RCS Pressure versus Time

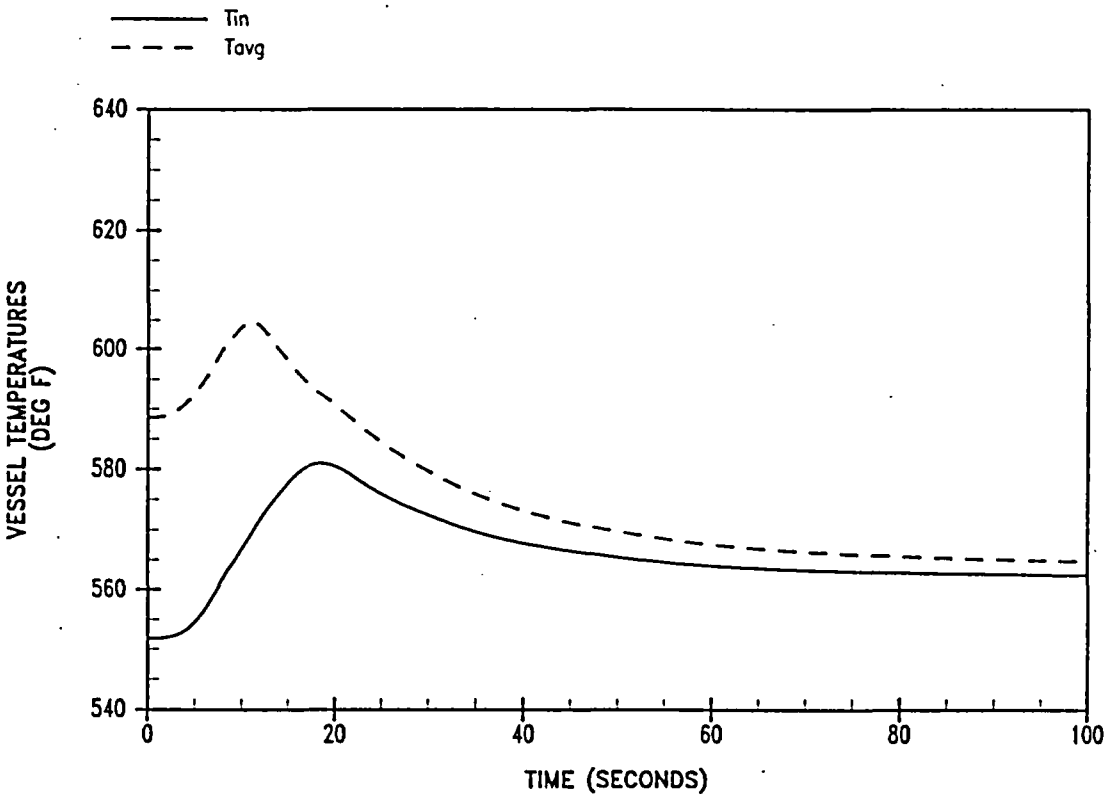


Figure 5.3.6-8A
BVPS-1 Loss of Load/Turbine Trip without Pressure Control
RCS Coolant Temperatures versus Time

5.3.7 Loss of Normal Feedwater

5.3.7.1 Identification of Causes and Accident Description

A loss of normal feedwater (from pump failures, valve malfunctions, or loss of offsite AC power) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If the reactor is not tripped during this accident, core damage would possibly occur as a result of the loss of heat sink while at power. If an alternative supply of feedwater is not supplied to the plant, residual heat following a reactor trip may heat the primary system water to the point where water relief from the pressurizer could occur. A significant loss of water from the RCS could lead to core uncovery and subsequent core damage. However, since a reactor trip occurs well before the steam generator heat transfer capability is reduced, the primary system conditions never approach those that would result in a violation of the limit DNBR.

The loss of normal feedwater that occurs as a result of the loss of AC power is discussed in Section 5.3.8.

The following events occur following the reactor trip for the loss of normal feedwater as a result of main feedwater pump failures or valve malfunctions:

a. As the steam system pressure rises following the trip, the steam system atmospheric relief valves are automatically opened to the atmosphere. Steam dump to the condenser is assumed not to be available. If the atmospheric relief valves are not available, the self-actuated main steam safety valves will lift to dissipate the sensible heat of the fuel and coolant plus the residual heat produced in the reactor.

b. As the no-load temperature is approached, the steam system atmospheric relief valves (or the self-actuated safety valves, if the atmospheric relief valves are not available) are used to dissipate the residual heat and to maintain the plant at the hot standby condition.

The following provide the necessary protection against core damage in the event of a loss of normal feedwater:

a. Reactor trip on low-low water level in any steam generator.

b. Turbine trip-Reactor trip on loss of feedwater in any two-out-of-three feedwater loops via the Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC).

c. Two motor-driven auxiliary feedwater (AFW) pumps that are started on:

   1. Either no bus loss of power, or diesel generator loading sequence signal coincident with any of the following:

      (a) Low-low water level in two out of three steam generators

      (b) Both main feedwater pumps stopped and either control switch for either main feed pump in close and after close position

(c) Safety injection signal

2. Manual actuation

3. Loss of feedwater in any two-out-of-three feedwater loops via the Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC)

d. One turbine-driven AFW pump that is started on:

1. Low-low water level in any steam generator

2. Undervoltage on any two of three reactor coolant pump buses

3. Manual actuation

4. Loss of feedwater in any two-out-of-three feedwater loops via the Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC)

5. Safety injection signal

The analysis shows that following a loss of normal feedwater, the AFW system is capable of removing the stored and residual heat thus preventing overpressurization of the RCS, overpressurization of the secondary side, water relief from the pressurizer, and uncovery of the reactor core.

5.3.7.2 Input Parameters and Assumptions

The following assumptions are made in the analysis:

a. The plant is initially operating at 100.6% of the NSSS power (100.6% of 2910 MWt). A maximum reactor coolant pump heat of 15.0 MWt is included in the analysis. The RCPs are assumed to continuously operate throughout the transient providing a constant reactor coolant volumetric flow equal to the Thermal Design Flow value. Although not assumed in the analysis, the reactor coolant pumps could be manually tripped at some later time in the transient to reduce the heat addition to the RCS caused by the operation of the pumps.

b. The direction of conservatism for both initial reactor vessel average coolant temperature and pressurizer pressure is not consistent from analysis to analysis. As such, cases are considered with the initial temperature and pressure uncertainties applied in each direction. The initial average temperature uncertainty is assumed to be +8.5° and -9.5°F which includes 3.5°F for loop-to-loop average temperature variations. The initial pressurizer pressure uncertainty is conservatively assumed to be ± 40 psi for BVPS-1. For BVPS-1, the worst loss of normal feedwater case is with the temperature uncertainty added to the nominal value and the pressure uncertainty subtracted from the nominal value (i.e., 588.5°F and 2210 psia for BVPS-1).

c. Reactor trip occurs on steam generator low-low water level at 5% of the narrow range span for BVPS-1.

d. It is assumed that two motor-driven AFW pumps are available to supply a minimum flow of 489 gpm for BVPS-1, split equally to all three steam generators, 60 seconds following a low-low steam generator water level signal. (The worst single failure, which is modeled in the analysis, is the loss of the turbine-driven AFW pump.) The AFW line purge volume is conservatively assumed to be 168 ft^3/loop for BVPS-1, and the initial AFW enthalpy is assumed to be 90.77 Btu/lbm.

e. The pressurizer sprays and PORVs are assumed operable. This maximizes the pressurizer water volume. If these control systems did not operate, the pressurizer safety valves would prevent the RCS pressure from exceeding the RCS design pressure limit during this transient. The pressurizer heaters are modeled to exacerbate the heatup and volumetric expansion of the water in the pressurizer.

f. Secondary system steam relief is achieved through the self-actuated main steam safety valves. Note that steam relief will, in fact, be through the steam generator atmospheric relief valves or condenser dump valves for most cases of loss of normal feedwater. However, the condenser dump valves and the atmospheric relief valves are assumed to be unavailable.

g. The main steam safety valves are modeled assuming a 3% tolerance and an accumulation model that assumes that the valves are wide open once the pressure exceeds the setpoint (plus tolerance) by 5 psi (accumulation).

h. Core residual heat generation is based on the 1979 version of ANS 5.1 (Reference 2). ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates. Long-term operation at the initial power level preceding the trip is assumed.

i. Steam generator tube plugging levels of both 0 and 22% are analyzed.

5.3.7.3 Description of Analysis

A detailed analysis using the LOFTRAN (Reference 1) computer code is performed in order to determine the plant transient conditions following a loss of normal feedwater. The code models the core neutron kinetics, RCS including natural circulation, pressurizer, pressurizer PORVs and sprays, steam generators, main steam safety valves, and the auxiliary feedwater system; and computes pertinent variables, including the pressurizer pressure, pressurizer water level, steam generator mass, and reactor coolant average temperature.

5.3.7.4 Acceptance Criteria and Results

Based on its frequency of occurrence, the loss of normal feedwater accident is considered a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this event:

- The critical heat flux shall not be exceeded. This is demonstrated by showing that the DNBR limit is not violated.

- Pressure in the reactor coolant and main steam systems shall be maintained below 110% of the design pressures.

With respect to DNB, the loss of normal feedwater accident is bounded by the loss of load accident reported in Section 5.3.6.

For ease in interpreting the transient results following a loss of normal feedwater, the following restrictive acceptance criterion is used: the pressurizer shall not become water solid.

The calculated sequence of events for this accident is listed in Table 5.3.7-1. Figures 5.3.7-1A through 5.3.7-5A present transient plots of the significant plant parameters following a loss of normal feedwater with the assumptions listed in Section 5.3.7.2.

Following the reactor and turbine trip from full load, the water level in the steam generators will fall due to reduction of the steam generator void fraction and because steam flow through the safety valves continues to dissipate the stored and generated heat. One minute following the initiation of the low-low level trip, the motor-driven AFW pumps automatically start, consequently reducing the rate at which the steam generator water level is decreasing.

The capacity of the motor-driven AFW pumps enables sufficient heat transfer from the three steam generators receiving auxiliary feedwater to dissipate the core residual heat without the pressurizer reaching a water solid condition (as shown in Figure 5.3.7-3A). This precludes any water relief through the RCS pressurizer relief or safety valves.

5.3.7.5 Conclusions

With respect to DNB, the loss of normal feedwater accident is bounded by the loss of load accident (Section 5.3.6) which demonstrates that the minimum DNBR is greater than the safety analysis limit value.

The results of the analysis show that pressurizer does not reach a water solid condition. Therefore, the loss of normal feedwater event does not adversely affect the core, the RCS, or the main steam system.

The results and conclusions of the analysis performed for the loss of normal feedwater for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

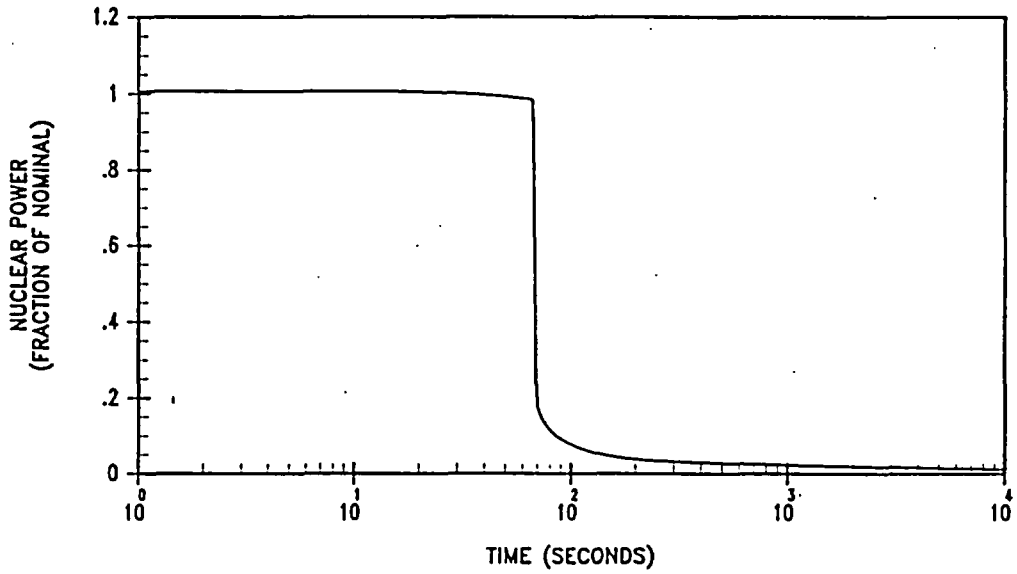
5.3.7.6 References

1. Burnett, T.W.T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.

2. ANSI/ANS-5.1 – 1979, "American National Standard for Decay Heat Power in Light Water Reactors," August 1979.

Table 5.3.7-1
Time Sequence of Events – Loss of Normal Feedwater

Event	BVPS-1 Time (seconds)	BVPS-2 Time (seconds)
Main feedwater flow stops	10	NA
Low-low steam generator water level reactor trip setpoint reached	63.3	NA
Rods begin to drop	65.3	NA
Peak water level in pressurizer occurs	1274.0	NA
Flow from two motor-driven AFW pumps is initiated	123.3	NA
Core decay and RCP heat decreases to AFW heat removal capacity	~ 1100	NA



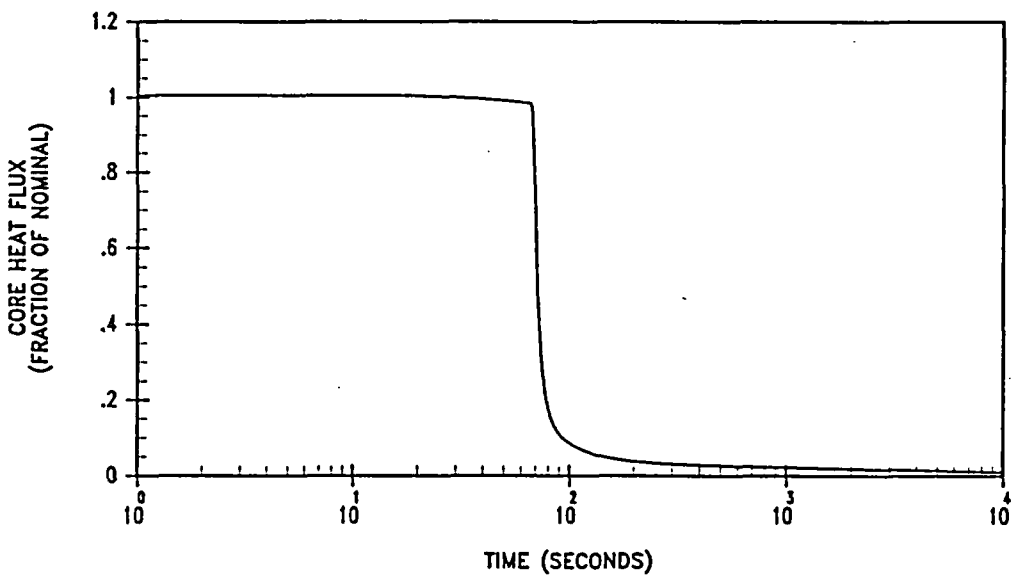
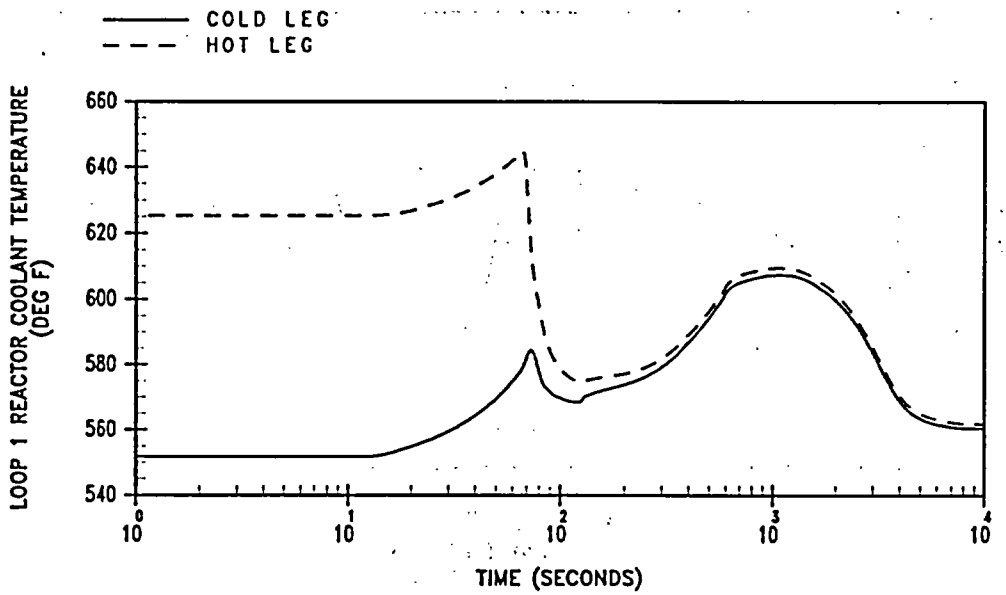


Figure 5.3.7-1A
BVPS-1 Loss of Normal Feedwater
Nuclear Power and Core Average Heat Flux versus Time



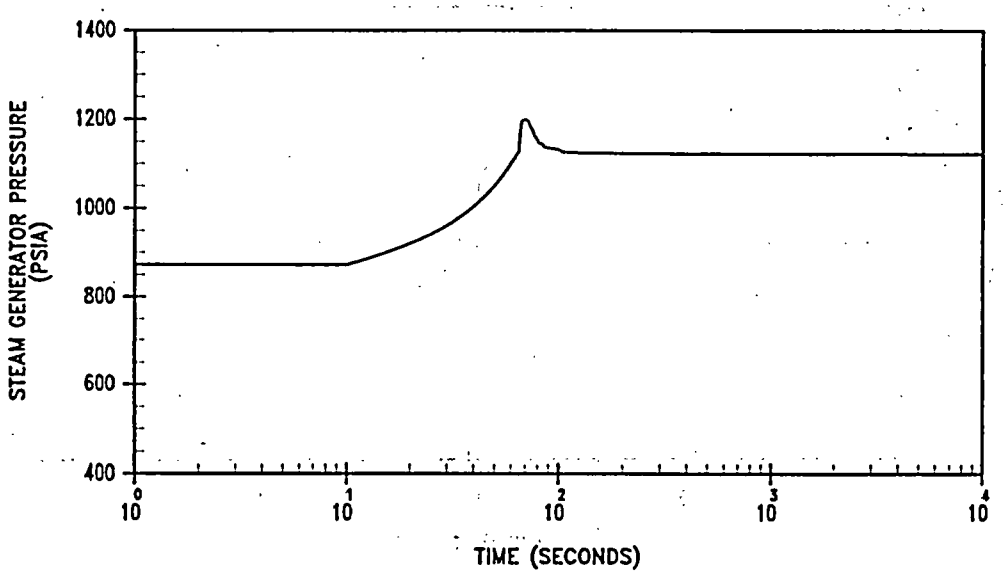
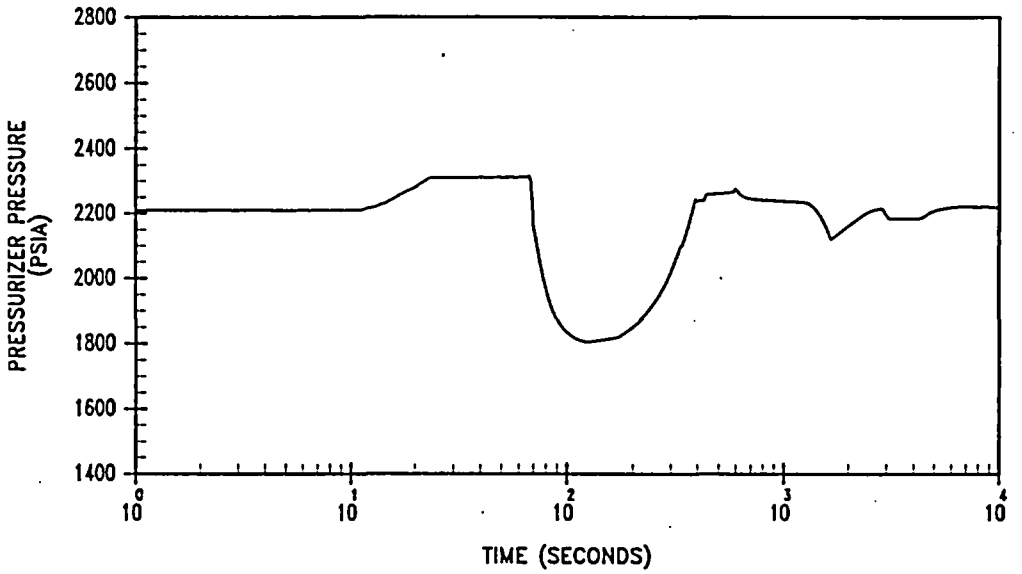


Figure 5.3.7-2A
BVPS-1 Loss of Normal Feedwater
RCS Temperatures and Steam Generator Pressure versus Time



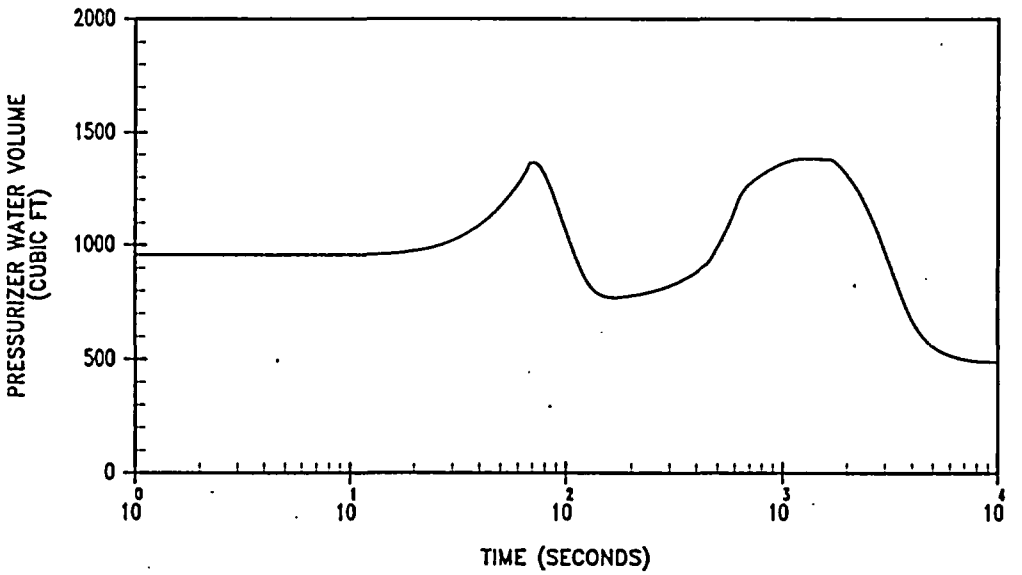
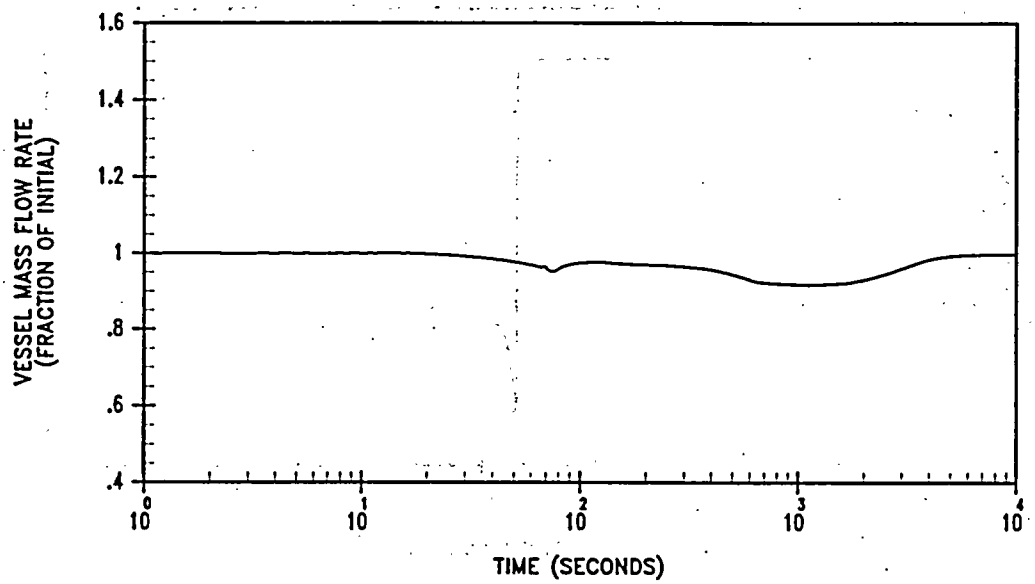


Figure 5.3.7-3A
BVPS-1 Loss of Normal Feedwater
Pressurizer Pressure and Water Volume versus Time



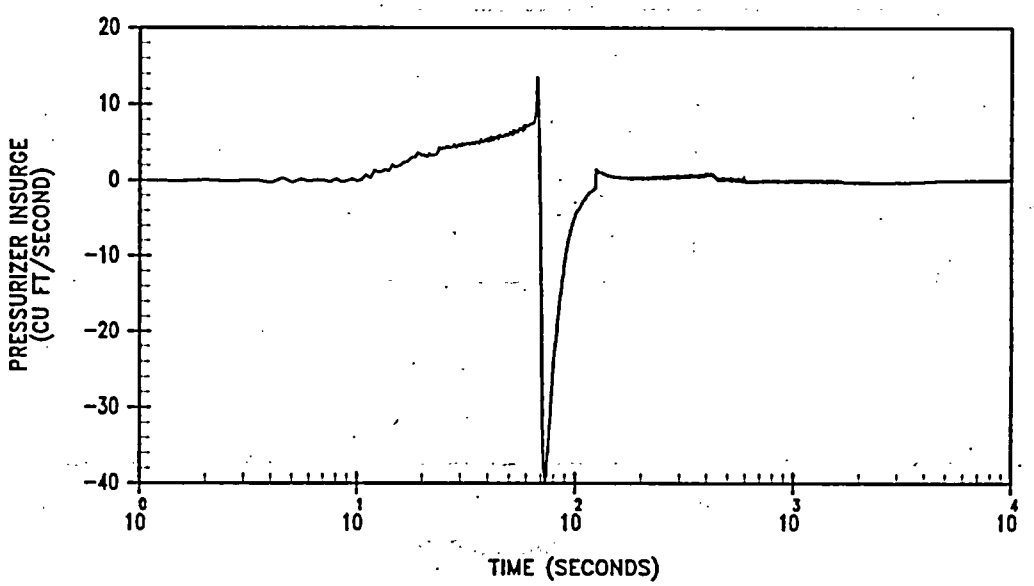
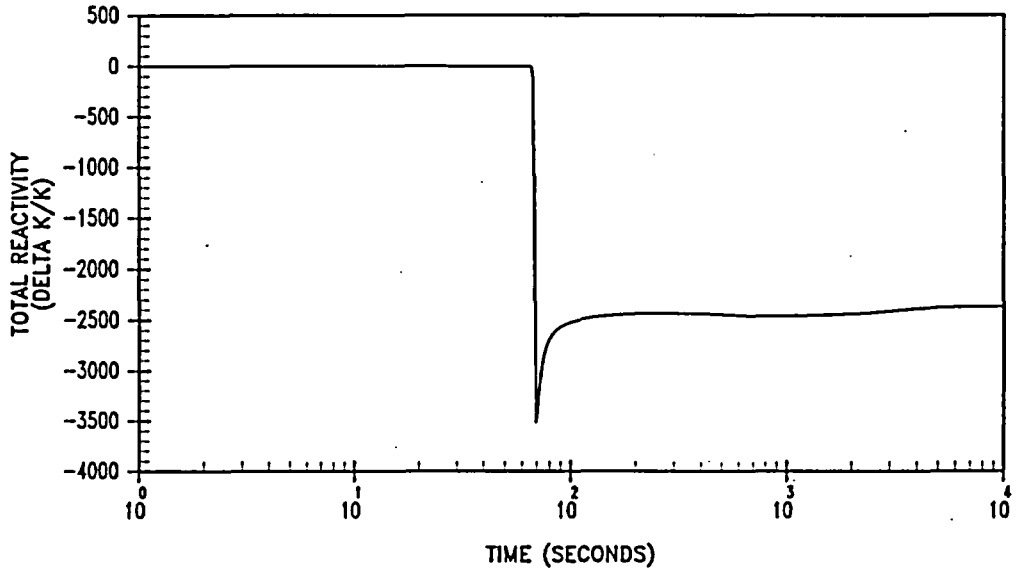


Figure 5.3.7-4A
BVPS-1 Loss of Normal Feedwater
Vessel Mass Flow Rate and Pressurizer Insurge versus Time



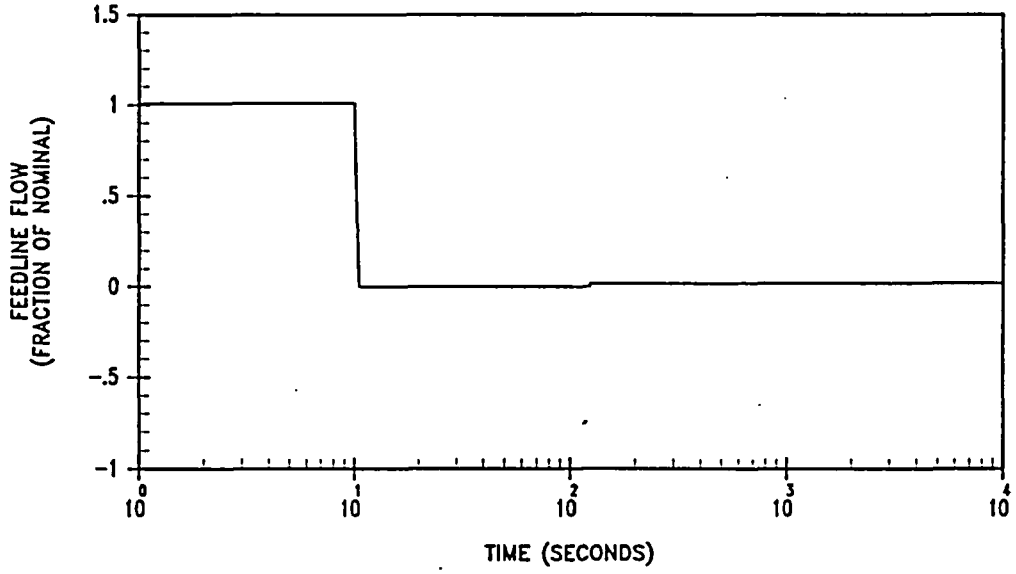


Figure 5.3.7-5A
BVPS-1 Loss of Normal Feedwater
Core Reactivity and Feedline Flow versus Time

5.3.8 Loss of Non-Emergency AC Power to the Plant Auxiliaries

5.3.8.1 Identification of Causes and Accident Description

A complete loss of non-emergency AC power will result in a loss of power to the plant auxiliaries, i.e., the reactor coolant pumps, condensate pumps, etc. The loss of power may be caused by a complete loss of the offsite grid accompanied by a turbine generator trip or by a loss of the onsite AC distribution system. The events following a loss of AC power with turbine and reactor trip are described in the sequence listed below:

a. The emergency diesel generators will start on a loss of voltage on the plant emergency buses and begin to supply plant vital loads.

b. Plant vital instruments are supplied by emergency power sources.

c. As the steam system pressure rises following the trip, the steam system power-operated relief valves are automatically opened to the atmosphere. Steam dump to the condenser is assumed not to be available. If the steam generator power-operated relief valves are not available, the self-actuated main steam safety valves will lift to dissipate the sensible heat of the fuel and coolant plus the residual heat produced in the reactor.

d. As the no-load temperature is approached, the steam system power-operated relief valves (or the self-actuated safety valves, if the power-operated relief valves are not available) are used to dissipate the residual heat and to maintain the plant at the hot standby condition.

The following provide the necessary protection against a loss of all AC power:

a. Reactor trip on low-low water level in any steam generator.

b. Turbine trip-Reactor trip on loss of feedwater in any two-out-of-three feedwater loops via the Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC).

c. Two motor-driven auxiliary feedwater (AFW) pumps that are started on:

   1. Either no bus loss of power, or diesel generator loading sequence signal coincident with any of the following:

      (a) Low-low water level in two out of three steam generators

      (b) Both main feedwater pumps stopped and control switch for either main feed pump in close and after close position

      (c) Safety injection signal

   2. Manual actuation

3. Loss of feedwater in any two-out-of-three feedwater loops via the Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC)

d. One turbine-driven AFW pump that is started on:

1. Low-low water level in any steam generator

2. Undervoltage on any two of three reactor coolant pump buses

3. Manual actuation

4. Loss of feedwater in any two-out-of-three feedwater loops via the Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC)

5. Safety injection signal

The auxiliary feedwater (AFW) system is initiated as discussed in the loss of normal feedwater analysis (Section 5.3.7). The Reactor Trip System and AFW system design provide reactor trip and AFW flow following any loss of normal feedwater.

Following the loss of power to the reactor coolant pumps (RCPs), coolant flow is necessary for core cooling and the removal of residual and decay heat.

Heat removal is maintained by natural circulation in the RCS loops. Following the RCP coastdown, the natural circulation capability of the RCS will remove decay heat from the core, aided by the AFW flow in the secondary system. Demonstrating that acceptable results can be obtained for this event proves that the resultant natural circulation flow in the RCS is adequate to remove decay heat from the core.

The first few seconds after a loss of AC power to the RCPs closely resembles the analysis of the complete loss of flow event (Section 5.3.14) in that the RCS would experience a rapid flow reduction transient. This aspect of the loss of AC power event is bounded by the analysis performed for the complete loss of flow event that demonstrates that the DNB design basis is met. The analysis of the loss of AC power event demonstrates that RCS natural circulation and the AFW system are capable of removing the stored and residual heat, and consequently will prevent RCS or main steam system overpressurization and core uncovery. The plant would therefore be able to return to a safe condition.

5.3.8.2 Input Parameters and Assumptions

The major assumptions used in this analysis are identical to those used in the loss of normal feedwater analysis (Section 5.3.7) with the following exceptions:

a. Loss of AC power is assumed to occur soon after the time of reactor trip on low-low SG water level. No credit is taken for the immediate insertion of the control rods as a result of the loss of AC power to the station auxiliaries.

b. Power is assumed to be lost to the RCPs. To maximize the amount of stored energy in the RCS, the power to the RCPs is not assumed to be lost until after the start of rod motion.

c. A heat transfer coefficient in the steam generators associated with RCS natural circulation is assumed following the RCP coastdown.

d. The RCS flow coastdown is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, the as-built pump characteristics and conservative estimates of system pressure losses.

e. For BVPS-1, the worst loss of non-emergency AC power case is with the temperature and the pressure uncertainties subtracted from the nominal value (i.e., 570.5°F and 2210 psia).

5.3.8.3 Description of Analysis

A detailed analysis using the LOFTRAN (Reference 1) computer code is performed in order to determine the plant transient following a loss of all AC power. The code describes the core neutron kinetics, RCS including natural circulation, pressurizer, pressurizer PORVs and sprays, steam generators, main steam safety valves, and the auxiliary feedwater system, and computes pertinent variables, including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

5.3.8.4 Acceptance Criteria and Results

Based on its frequency of occurrence, the loss of non-emergency AC power accident is considered a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this event:

- The critical heat flux shall not be exceeded. This is demonstrated by showing that the DNBR limit is not violated.
- Pressure in the reactor coolant and main steam systems shall be maintained below 110% of the design pressures.

With respect to DNB, the loss of non-emergency AC power accident is bounded by the loss of flow accident reported in Section 5.3.14.

For ease in interpreting the transient results following a loss of non-emergency AC power, the following restrictive acceptance criterion has been used: the pressurizer shall not become water solid.

Figures 5.3.8-1A through 5.3.8-5A present transient plots of plant parameters following a loss of non-emergency AC power with the assumptions listed in Section 5.3.8.2. The calculated sequence of events for this accident is listed in Table 5.3.8-1.

The first few seconds after the loss of non-emergency AC power to the RCPs, the flow transient for a loss of non-emergency AC power event closely resembles the complete loss of flow incident, where core

damage due to rapidly increasing core temperatures is prevented by the reactor trip, which, for a loss of non-emergency AC power event, is on a low-low steam generator water level signal. After the reactor trip, stored and residual heat must be removed to prevent damage to the core and the reactor coolant and main steam systems. The LOFTRAN code results show that the natural circulation and AFW flow available is sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

Figure 5.3.8-3A illustrates that the pressurizer never reaches a water solid condition. Hence, no water relief from the pressurizer occurs.

5.3.8.5 Conclusions

With respect to DNB, the loss of non-emergency AC power event is bounded by the complete loss of flow event (Section 5.3.14) which demonstrated that the minimum DNBR is greater than the safety analysis limit value.

The results of the analysis show that the pressurizer does not reach a water solid condition. Therefore, the loss of offsite power event does not adversely affect the core, the RCS, or the main steam system.

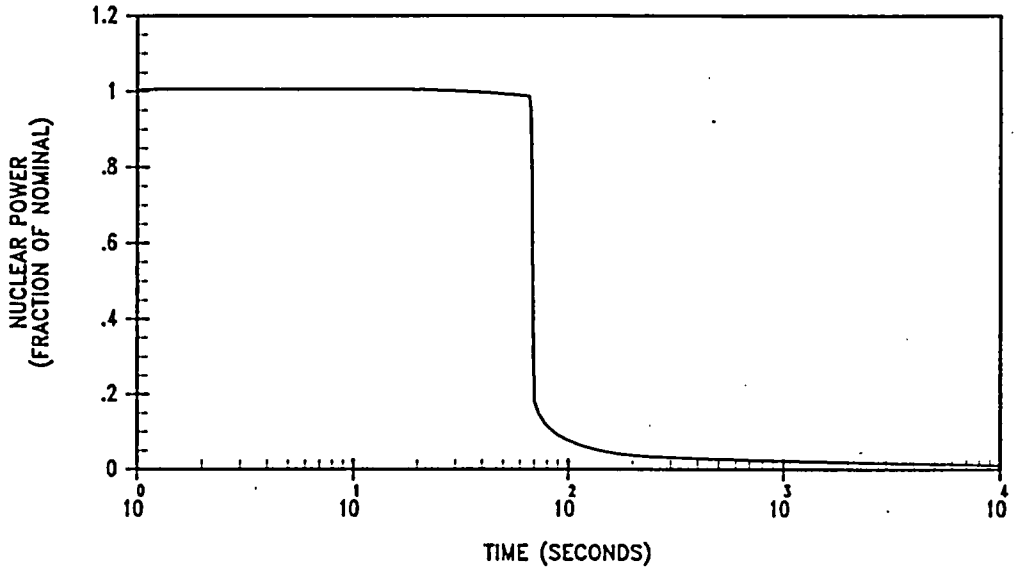
The results and conclusions of the analysis performed for the loss of non-emergency AC power to the plant auxiliaries for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

5.3.8.6 References

1. Burnett, T.W.T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.

Table 5.3.8-1
Time Sequence of Events – Loss of Non-Emergency AC Power to the Plant Auxiliaries

Event	BVPS-1 Time (seconds)	BVPS-2 Time (seconds)
Main feedwater flow stops	10	NA
Low-low steam generator water level reactor trip setpoint reached	63.6	NA
Rods begin to drop	65.6	NA
Reactor coolant pumps begin to coastdown	67.6	NA
Peak water level in pressurizer occurs as a result of decay heat	844.0	NA
Flow from two motor-driven AFW pumps is initiated	123.6	NA
Core decay heat decreases to AFW heat removal capacity	~750	NA



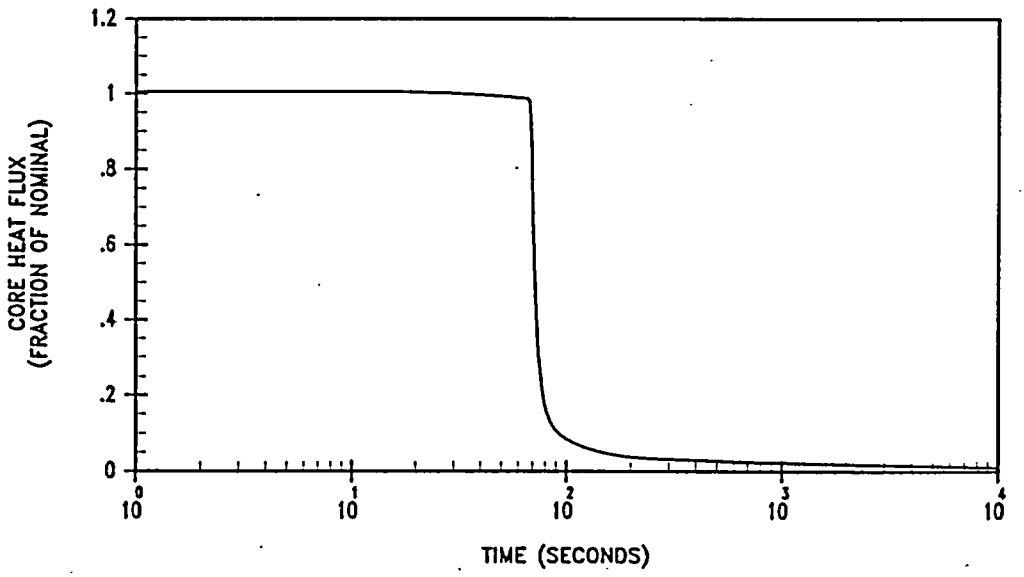


Figure 5.3.8-1A
BVPS-1 Loss of All Offsite AC Power to the Plant Auxiliaries
Nuclear Power and Core Average Heat Flux versus Time

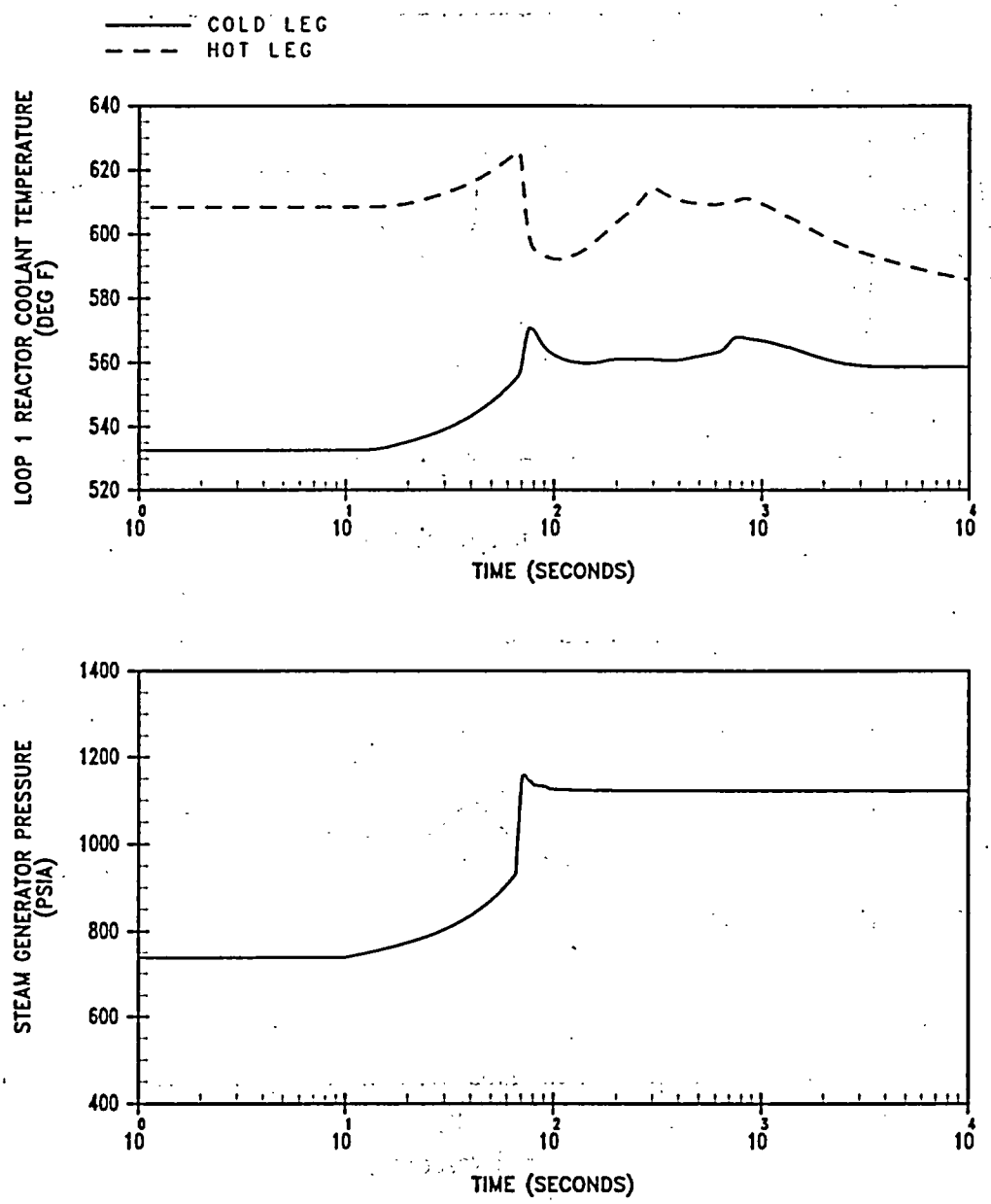
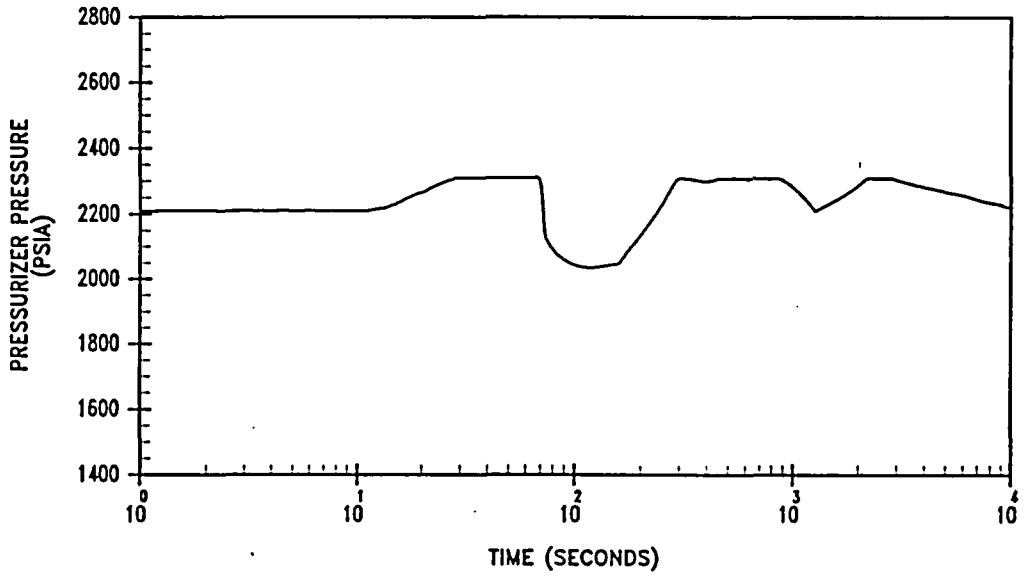


Figure 5.3.8-2A
BVPS-1 Loss of All Offsite AC Power to the Plant Auxiliaries
RCS Temperatures and Steam Generator Pressure versus Time



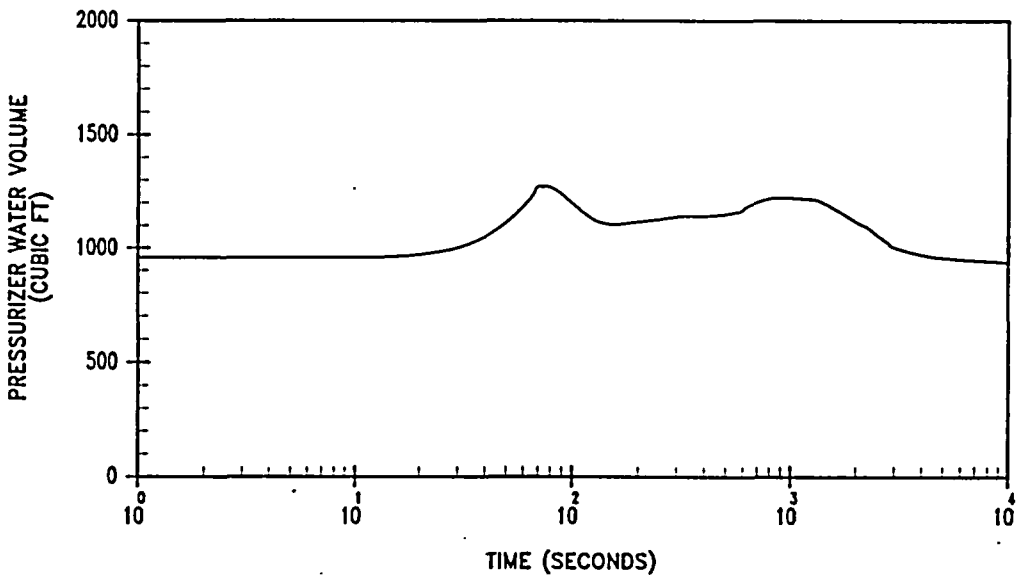
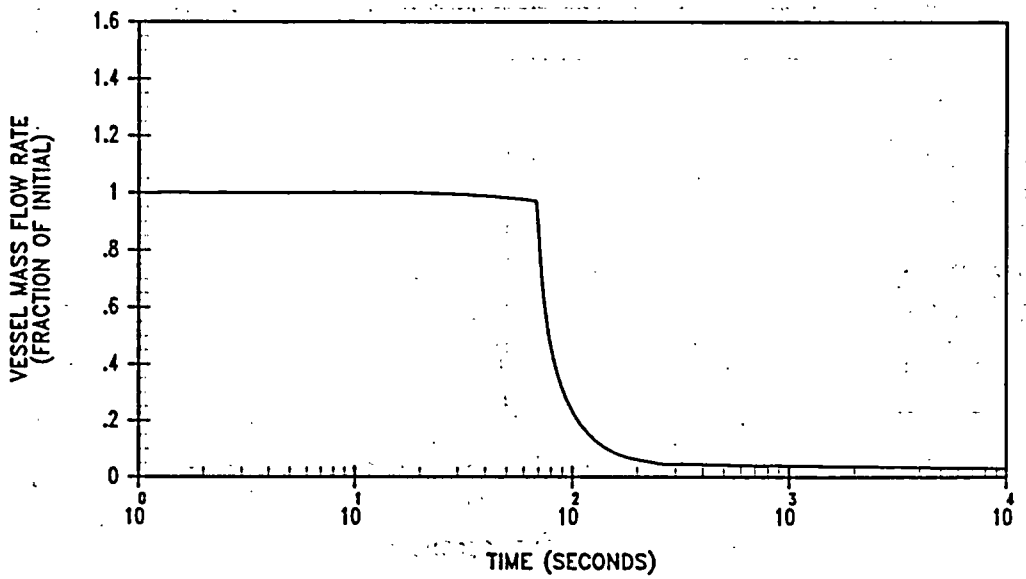


Figure 5.3.8-3A
BVPS-1 Loss of All Offsite AC Power to the Plant Auxiliaries
Pressurizer Pressure and Water Volume versus Time



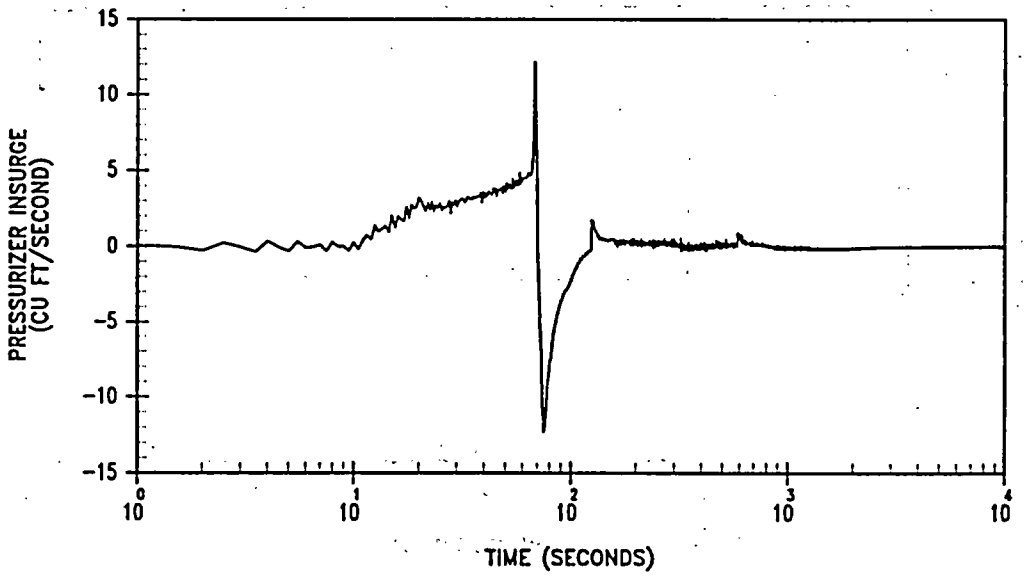
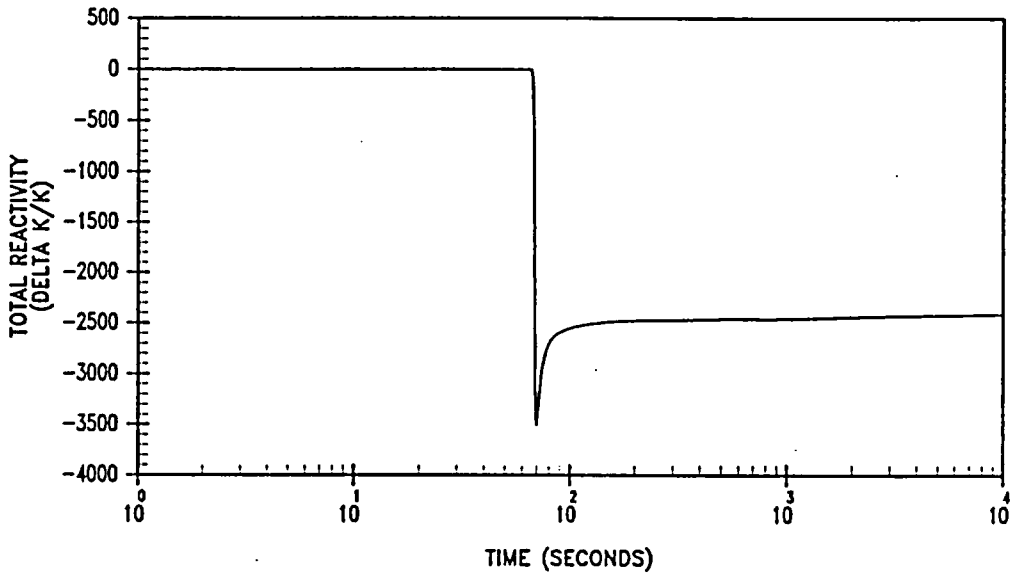


Figure 5.3.8-4A
BVPS-1 Loss of All Offsite AC Power to the Plant Auxiliaries
Vessel Mass Flow Rate and Pressurizer Insurge versus Time



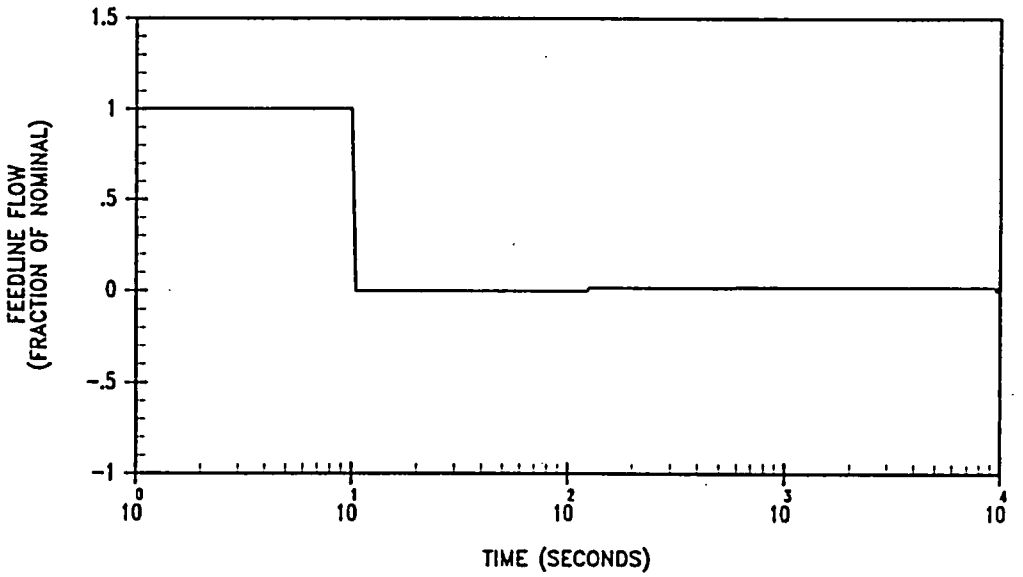


Figure 5.3.8-5A
BVPS-1 Loss of All Offsite AC Power to the Plant Auxiliaries
Core Reactivity and Feedline Flow versus Time

5.3.9 Excessive Heat Removal Due To Feedwater System Malfunctions

5.3.9.1 Identification of Causes and Accident Description

Reductions in feedwater temperature or excessive feedwater additions are means of increasing core power above full power. Such transients are attenuated by the thermal capacity of the RCS and the secondary side of the plant. The overpower/overtemperature protection functions (neutron high flux, overtemperature ΔT, and overpower ΔT trips) prevent any power increase that could lead to a DNBR that is less than the limit value.

An example of excessive feedwater flow would be a full opening of one feedwater control valve due to a feedwater control system malfunction or an operator error. At power, this excess flow causes a greater load demand on the RCS due to increased subcooling in the steam generator. With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in RCS temperature and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient of reactivity. Continuous excessive feedwater addition is prevented by the steam generator high-high water level trip.

A second example of excess heat removal is the transient associated with failure of the low-pressure heaters' bypass valve resulting in an immediate reduction in feedwater temperature. At power, this increased subcooling will create a greater load demand on the RCS.

5.3.9.2 Input Parameters and Assumptions

The reactivity insertion rate following a feedwater system malfunction, attributed to the cooldown of the RCS, is calculated with the following assumptions:

a. This accident is analyzed with the Revised Thermal Design Procedure as described in Reference 1. Initial reactor power, RCS pressure, and RCS temperature are assumed to be at their nominal values, adjusted to account for any applicable measurement biases, consistent with steady-state full power operation. Minimum Measured Flow is modeled. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 1.

b. The analyses are done at the NSSS power level of 2910 MWt.

c. For the feedwater control valve accident at full-power conditions that result in an increase in feedwater flow to one steam generator, one feedwater control valve is assumed to malfunction resulting in a step increase to 162% for BVPS-1 of nominal full power feedwater flow to one steam generator.

d. The increase in feedwater flow rate results in a decrease in the feedwater temperature due to the reduced efficiency of the feedwater heaters. For the hot full power cases, a 51.4°F for BVPS-1 decrease in the feedwater temperature is assumed to occur coincident with the feedwater flow increase.

e. For the feedwater control valve accident at zero-load conditions that result in an increase in feedwater flow to one steam generator, one feedwater control valve is assumed to malfunction

resulting in a step increase to 187% for BVPS-1 of the nominal full-load value for one steam generator.

f. For cases at zero-load conditions, a feedwater temperature is at a conservatively low 32°F.

g. The initial water level in all the steam generators is a conservatively low level.

h. No credit is taken for the heat capacity of the RCS and steam generator metal mass in attenuating the resulting plant cooldown.

i. The feedwater flow resulting from a fully open control valve is terminated by the steam generator high-high water level signal that closes all feedwater main control and feedwater control-bypass valves, indirectly closes all feedwater pump discharge valves, and trips the main feedwater pumps and turbine generator.

The reactor protection system features, including Power-Range High Neutron Flux, Overpower ΔT, and Turbine Trip on High-High Steam Generator Water Level, are available to provide mitigation of the feedwater system malfunction transient.

Normal reactor control systems and engineered safety systems (e.g., SI) are not assumed to function. The reactor protection system may actuate to trip the reactor due to an overpower condition. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

5.3.9.3 Description of Analysis

The excessive heat removal due to a feedwater system malfunction transient is analyzed with the LOFTRAN (Reference 2) computer code. This code simulates a multiloop system, neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and main steam safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The excessive feedwater flow event assumes an accidental opening of one feedwater control valve with the reactor at both full and zero power conditions with both automatic and manual rod control. Both the automatic and manual rod control cases assume a conservatively large moderator density coefficient characteristic of EOL conditions.

The feedwater temperature reduction event assumes the accidental opening of the low-pressure heaters' bypass valve, resulting in a decrease in feedwater temperature to all three steam generators. The analysis assumes a conservatively large moderator density coefficient characteristic of EOL conditions. This event is similar to the excessive feedwater flow event in that it creates an increased thermal load on the RCS.

5.3.9.4 Acceptance Criteria and Results

Based on its frequency of occurrence, the feedwater system malfunction event is considered a Condition II event as defined by the American Nuclear Society (ANS). Even though DNB is the primary

concern in the analysis of the Feedwater Malfunction event, the following three items summarize the criteria associated with this transient:

- The critical heat flux shall not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the reactor coolant and main steam systems shall be maintained below 110% of the design pressures.
- The peak linear heat generation rate should not exceed a value that would cause fuel centerline melt.

The excessive feedwater flow full-power case (EOL maximum reactivity feedback with automatic rod control) gives the largest reactivity feedback and results in the greatest power increase. A turbine trip, which results in a reactor trip, is actuated when the steam generator water level in the affected steam generator reaches the high-high water level setpoint. However, the trips are not required to meet the DNBR criterion. Assuming the reactor to be in manual rod control results in a slightly less severe transient. The rod control system is not required to function for this event; however, assuming that the rod control system is operable yields a slightly more limiting transient.

The case initiated at hot zero power conditions with manual rod control, is less limiting than the full power case. Therefore, the results for this case are not presented.

For all cases of excessive feedwater flow, continuous addition of cold feedwater is prevented by automatic closure of all feedwater control and isolation valves, closure of all feedwater bypass valves, a trip of the feedwater pumps, and a turbine trip on high-high steam generator water level. In addition, the feedwater pump discharge isolation valves will automatically close upon receipt of the feedwater pump trip signal.

Following turbine trip, the reactor will automatically be tripped, either directly due to the turbine trip or due to one of the reactor trip signals discussed in Section 5.3.6 (Loss of External Electrical Load and/or Turbine Trip). If the reactor was in automatic rod control, the control rods would be inserted at the maximum rate following the turbine trip, and the resulting transient would not be limiting in terms of peak RCS pressure.

The effects of the RTDP methodology, including rod control system response characteristics were incorporated into the analysis. Table 5.3.9-1 shows the time sequence of events for the hot full power feedwater malfunction transient. Figures 5.3.9-1A and 5.3.9-2A show transient responses for various system parameters during a feedwater system malfunction initiated from hot full power conditions with automatic rod control.

The accidental opening of the low-pressure heaters' bypass valve causes a reduction in the feedwater temperature which increases the thermal load on the primary system. The increased thermal load would result in a transient very similar to the feedwater flow increase discussed above with exception of reactor trip, which is provided by the Overpower ΔT function. An evaluation has been performed that shows that

all applicable Condition II acceptance criteria are met for a feedwater system malfunction event which results in a decrease in the feedwater enthalpy.

5.3.9.5 Conclusions

For the excessive feedwater addition at power transient, the results show that the DNBRs encountered are above the limit value; hence, no fuel damage is predicted.

The decrease in feedwater temperature transient due to the failure of one or more low-pressure heaters is similar to the feedwater flow increase event discussed in detail in this section.

The protection features presented in Section 5.3.9.2 provide mitigation of the feedwater system malfunction transient such that the above criteria are satisfied.

The results and conclusions of the analysis performed for the excessive heat removal due to feedwater system malfunction for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

5.3.9.6 References

1. Friedland, A. J., and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), April 1989.

2. Burnett, T.W.T. et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-Proprietary)," April 1984.

Table 5.3.9-1
Time Sequence of Events – Excessive Heat Removal Due to Feedwater System Malfunctions

Event	BVPS-1 Time (seconds)	BVPS-2 Time (seconds)
One main feedwater control valve fails full open	0	NA
Minimum DNBR occurs	111.0	NA
Hi-Hi steam generator water level trip setpoint is reached	108.9	NA
Turbine trip occurs due to hi-hi steam generator level	111.4	NA
Rod motion begins	113.4	NA
Feedwater isolation valves begin to close	118.9	NA

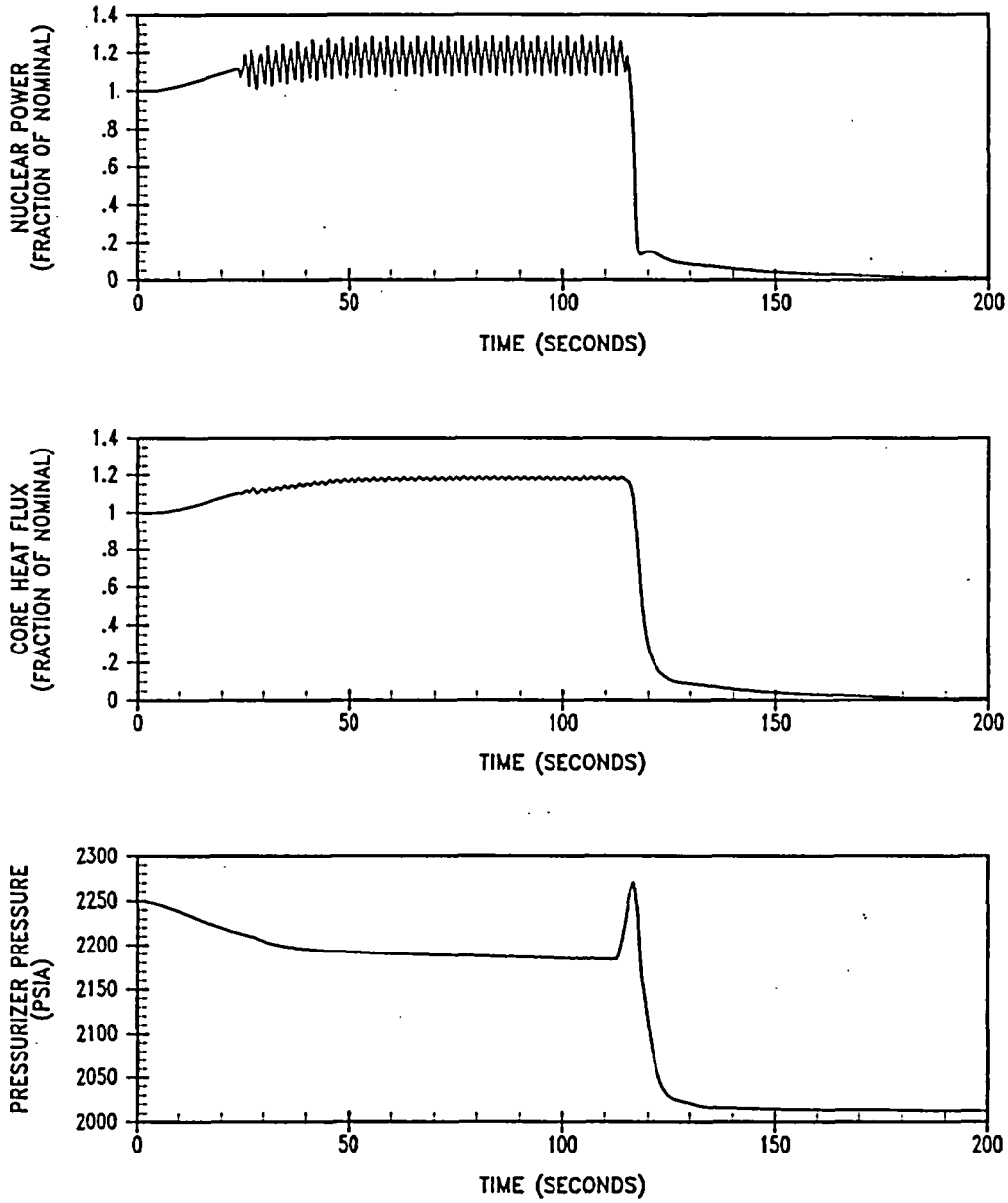


Figure 5.3.9-1A
BVPS-1 Feedwater System Malfunction at Full Power
Nuclear Power, Core Heat Flux and Pressurizer Pressure versus Time

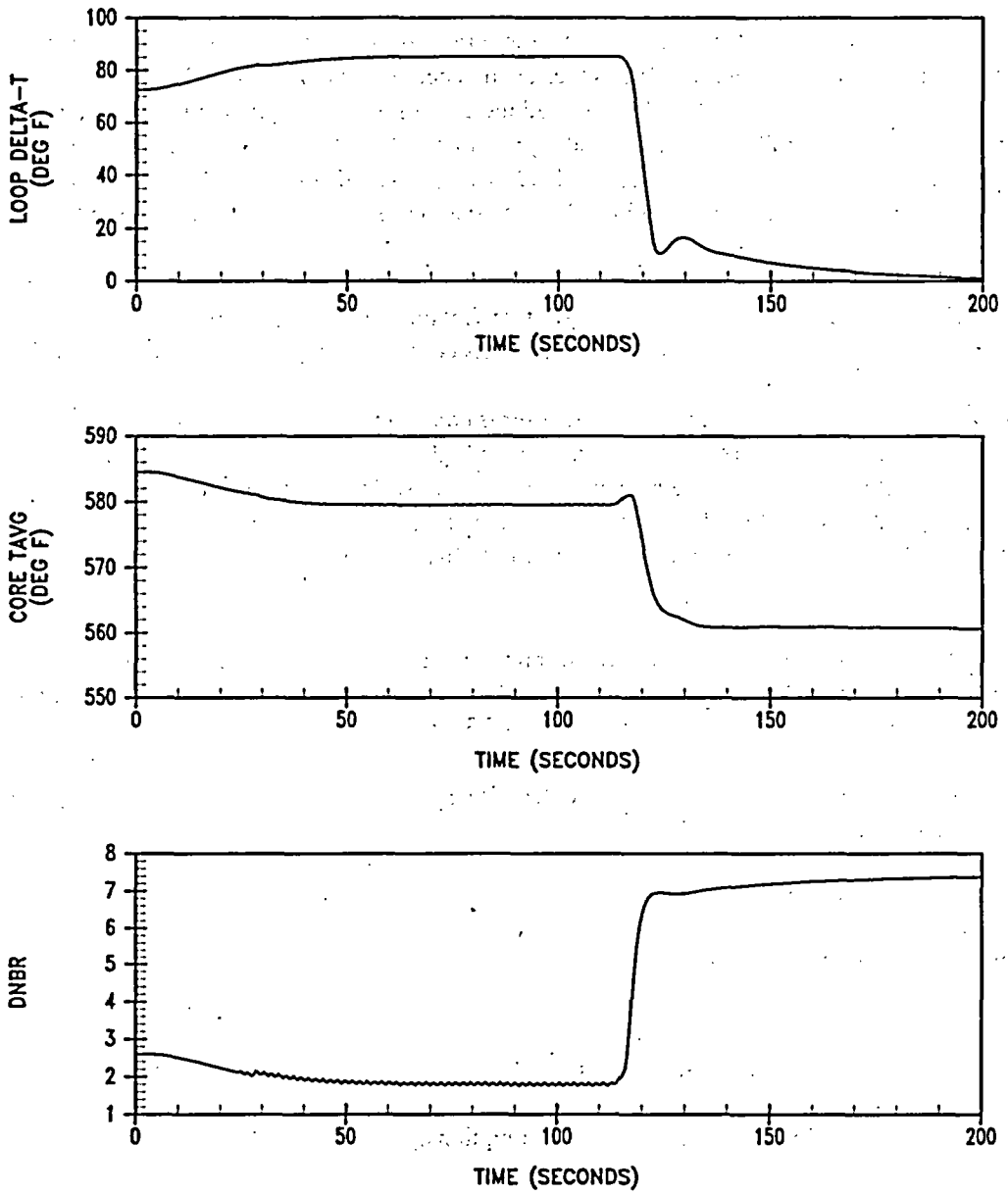


Figure 5.3.9-2A
BVPS-1 Feedwater System Malfunction at Full Power
Loop Delta-T, Core Average Temperature and DNBR versus Time

5.3.10 Excessive Load Increase Incident

5.3.10.1 Identification of Cause and Accident Description

An excessive load increase incident is defined as a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a 10% step-load increase or a 5% per minute ramp-load increase in the range of 15 to 100% of full power. Any loading rate in excess of these values may cause a reactor trip actuated by the reactor protection system. If the load increase exceeds the capability of the reactor control system, the transient would be terminated in sufficient time to prevent the DNB design basis from being violated.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam bypass control system or turbine speed control.

During power operation, steam dump to the condenser is controlled by comparing the RCS temperature to a reference temperature based on turbine power, where a high temperature difference in conjunction with a loss of load or turbine trip indicates a need for steam dump. A single controller malfunction does not cause steam dump valves to open. Interlocks are provided to block the opening of the valves unless a large turbine load decrease or a turbine trip has occurred. In addition, the reference temperature and loss of load signals are developed by independent sensors.

Regardless of the rate of load increase, the reactor protection system will trip the reactor in time to prevent the DNBR from going below the limit value. Increases in steam load to more than design flow are analyzed as the steam line rupture event in Section 5.3.12.

Protection against an excessive load increase accident, if necessary, is provided by the following reactor protection system signals:

- Overtemperature ΔT
- Overpower ΔT
- Power range high neutron flux
- Low pressurizer pressure

5.3.10.2 Input Parameters and Assumptions

The analysis includes the following conservative assumptions:

- This accident is analyzed with the Revised Thermal Design Procedure as described in Reference 1. Initial reactor power, RCS pressure and RCS temperature are assumed to be at their nominal values, adjusted to account for any applicable measurement biases, consistent with steady-state full power operation. Minimum Measured Flow is modeled. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 1.

- The evaluation is performed for a step load increase of 10% steam flow from 100% of NSSS thermal power.

- This event is analyzed in both automatic and manual rod control.

- The excessive load increase event is analyzed for both the beginning-of-life (minimum reactivity feedback) and end-of-life (maximum reactivity feedback) conditions. A small (zero) moderator density coefficient at beginning of life and a large value at end of life are used. A positive moderator temperature coefficient is not assumed since this would provide a transient benefit. For all cases, a small (absolute value) Doppler coefficient of reactivity is assumed.

5.3.10.3 Description of Analysis

Historically, four cases are analyzed, and presented in the UFSAR, to demonstrate the plant behavior following a 10% step-load increase from 100% load. These cases are as follows:

- Reactor in manual rod control with BOL (minimum moderator) reactivity feedback
- Reactor in manual rod control with EOL (maximum moderator) reactivity feedback
- Reactor in automatic rod control with BOL (minimum moderator) reactivity feedback
- Reactor in automatic rod control with EOL (maximum moderator) reactivity feedback

At BOL, minimum moderator feedback cases, the core has the least-negative moderator temperature coefficient of reactivity and the least-negative Doppler only power coefficient curve; therefore, the least-inherent transient response capability. Since a positive moderator temperature coefficient would provide a transient benefit, a zero moderator temperature coefficient is assumed in the minimum feedback cases. For the EOL maximum moderator feedback cases, the moderator temperature coefficient of reactivity has its most-negative value and the most-negative Doppler only power coefficient curve. This results in the largest amount of reactivity feedback due to changes in coolant temperature. Normal reactor control systems and engineered safety systems are not required to function. A 10% step increase in steam demand is assumed and the analysis does not take credit for the operation of the pressurizer heaters. The cases which assume automatic rod control are analyzed to ensure that the worst case is presented. The automatic function is not required. The reactor protection system is assumed to be operable; however, reactor trip is not encountered for the cases analyzed. No single active failure in any system or component required for mitigation will adversely affect the consequences of this accident. Given the non-limiting nature of this event with respect to the DNBR safety analysis criterion, an explicit LOFTRAN analysis was not performed as part of the EPU. Instead, an evaluation of this event was performed. The evaluation model consists of the generation of statepoints based on generic conservative data. The statepoints are then compared to the core thermal limits to ensure that the DNBR limit is not violated. A total of three cases are included in the evaluation. These are:

- Reactor in manual rod control with BOL (minimum moderator) reactivity feedback
- Reactor in manual rod control with EOL (maximum moderator) reactivity feedback
- Reactor in automatic rod control (both minimum/maximum moderator)

5.3.10.4 Acceptance Criteria and Results

Based on its frequency of occurrence, the excessive load increase accident is considered a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this event:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the reactor coolant and main steam systems should be maintained below 110% of the design pressures.
- The peak linear heat generation rate (expressed in kw/ft) should not exceed a value which would cause fuel centerline melt.

The evaluation confirms that for an excessive load increase, the minimum DNBR during the transient will not go below the safety analysis limit value and the peak linear heat generation does not exceed the limit value; thus demonstrating that the applicable acceptance criteria for critical heat flux and fuel centerline melt are met. Following the initial load increase, the plant reaches a stabilized condition. With respect to peak pressure, the excessive load increase accident is bounded by the loss of electrical load/turbine trip analysis. The loss of electrical load/turbine trip analysis is described in Section 5.3.6.

5.3.10.5 Conclusions

The evaluation performed for the EPU demonstrates that, for an excessive load increase incident, the DNBR does not decrease below the safety analysis limit value at any time during the transient; thus, no fuel or clad damage is predicted. The peak primary and secondary system pressures remain below their respective limits at all times. All applicable acceptance criteria are therefore met.

The protection features presented in Section 5.3.10.1 provide mitigation for the excessive load increase.. incident such that the above criteria are satisfied.

The results and conclusions of the analysis performed for the excessive load increase incident for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

5.3.10.6 References

1. Friedland, A. J., and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A, (Proprietary), WCAP-11397-A (Non-proprietary), April 1989.

5.3.11 Accidental Depressurization of the RCS

5.3.11.1 Identification of Causes and Accident Description

An accidental depressurization of the reactor coolant system (RCS) could occur as a result of an inadvertent opening of a pressurizer relief valve. To conservatively bound this scenario, the

Westinghouse methodology models the failure of a pressurizer safety valve since a safety valve is sized to relieve approximately twice the steam flowrate of a relief valve and will allow a much more rapid depressurization upon opening. This yields the most-severe core conditions resulting from an accidental depressurization of the RCS. Initially, the event results in a rapidly decreasing RCS pressure, which could reach hot leg saturation conditions without reactor protection system intervention. If saturated conditions are reached, the rate of depressurization is slowed considerably. However, the pressure continues to decrease throughout the event. The effect of the pressure decrease is to increase power via the moderator density feedback (note that a positive moderator temperature coefficient is assumed). However, if the plant is in the automatic mode, the rod control system functions to maintain the power essentially constant throughout the initial stages of the transient. The average coolant temperature remains approximately the same, but the pressurizer level increases until reactor trip because of the decreased reactor coolant density.

The reactor may be tripped by the following reactor protection system signals:

a. Low pressurizer pressure
b. Overtemperature ΔT

5.3.11.2 Input Parameters and Assumptions

In order to produce conservative results in calculating the DNBR during the transient, the following assumptions are made:

a. The accident is analyzed using the Revised Thermal Design Procedure (Reference 1). Initial core power, RCS pressure and RCS temperature are assumed to be at their nominal values, adjusted to account for any applicable measurement biases, consistent with steady-state full power operation. Minimum Measured Flow is modeled. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 1. The initial power level assumed is 2910 MWt consistent with the EPU.

b. A +5 pcm/°F moderator temperature coefficient of reactivity is assumed in order to provide a conservatively high amount of positive reactivity feedback due to changes in the moderator temperature.

c. A small (absolute value) Doppler coefficient of reactivity is assumed, such that the resultant amount of negative feedback is conservatively low in order to maximize any power increase due to moderator feedback.

d. The spatial effect of voids resulting from local or subcooled boiling is not considered in the analysis with respect to reactivity feedback or core power shape. In fact, it should be noted, the power peaking factors are kept constant at their design values, while the void formation and resulting core feedback effects would result in considerable flattening of the power distribution. Although this would significantly increase the calculated DNBR, no credit is taken for this effect.

5.3.11.3 Description of Analysis

The purpose of this analysis is to demonstrate the manner in which the protection functions described above actuate to mitigate the consequences of the RCS depressurization event.

The accident is analyzed by using the detailed digital computer code LOFTRAN (Reference 2). This code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

5.3.11.4 Acceptance Criteria and Results

Based on its frequency of occurrence, the accidental depressurization for the RCS accident is considered a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this event:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the reactor coolant and main steam systems should be maintained below 110% of the design pressures.

The system response to an inadvertent opening of a pressurizer safety valve is shown in Figures 5.3.11-1A through 5.3.11-3A. Figure 5.3.11-1A illustrates the nuclear power transient following the depressurization. Nuclear power increases slowly until the reactor trip occurs on low pressurizer pressure. The pressurizer pressure transient is illustrated in Figure 5.3.11-2A. Pressure decreases continuously throughout the transient, however, pressure decreases more rapidly after core heat generation is reduced via the reactor trip. If the saturation temperature is reached in the hot leg the pressure decrease slows. Also illustrated in Figure 5.3.11-2A is the core average temperature transient. Core average temperature is maintained at approximately the initial value until the reactor trip occurs on low pressurizer pressure. The DNBR decreases initially, but increases rapidly following the reactor trip as demonstrated in Figure 5.3.11-3A. The DNBR remains above the limit value throughout the transient.

The calculated sequence of events is shown in Table 5.3.11-1.

5.3.11.5 Conclusions

The results of the analysis show that the pressurizer low pressure and OTΔT reactor protection system signals provide adequate protection against the RCS depressurization event since the minimum DNBR remains above the safety analysis limit throughout the transient. Thus no cladding damage or release of fission products to the RCS is predicted for this event.

The protection features described in Section 5.3.11.1 provide mitigation of the effects of the accidental depressurization of the RCS transient such that the above criteria are satisfied.

The results and conclusions of the analysis performed for the accidental depressurization of the RCS for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

5.3.11.6 References

1. A. J. Friedland and S. Ray, "Revised Thermal Design Procedure," WCAP-11397-P-A, April 1989.

2. T.W.T. Burnett, et al., "LOFTRAN Code Description," WCAP-7907-A (Proprietary) and WCAP-7907-A (Non-proprietary), April 1984.

Table 5.3.11-1
Time Sequence of Events – Accidental Depressurization of the RCS

Event	BVPS-1 Time (sec)	BVPS-2 Time (sec)
Inadvertent opening of one RCS relief valve *	0.0	NA
Low Pressurizer Pressure reactor trip setpoint reached	16.9	NA
Rods begin to drop	18.9	NA
Minimum DNBR occurs	19.8	NA

* Relief capacity of a pressurizer safety valve is conservatively assumed.

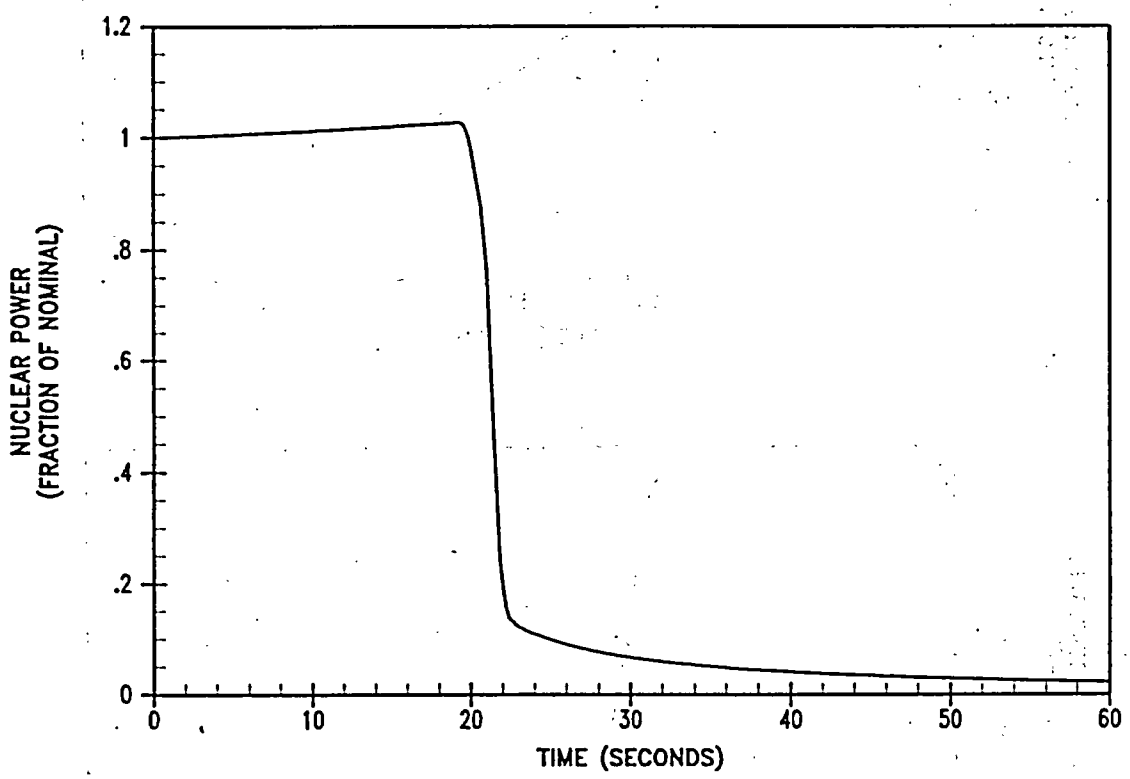
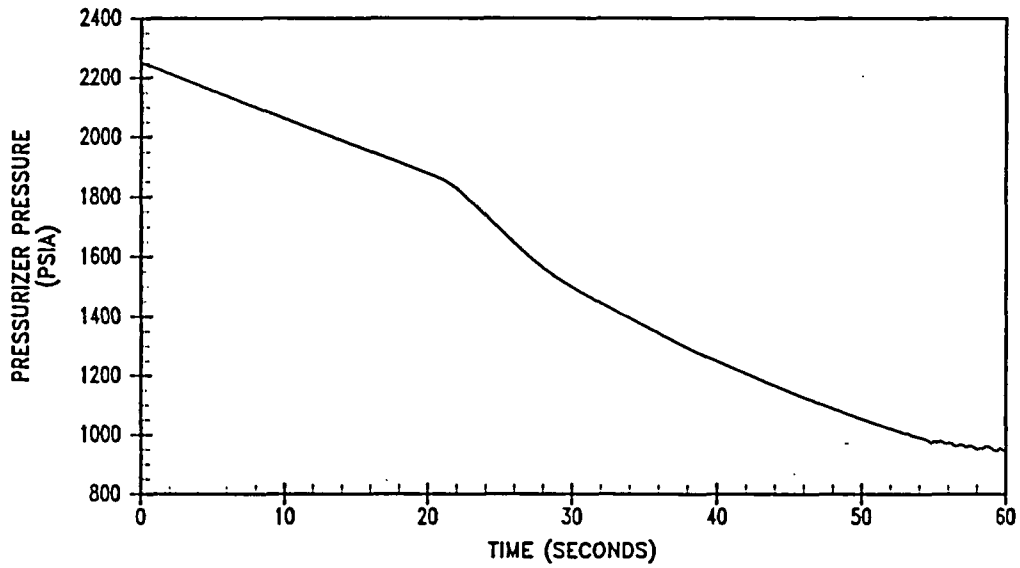


Figure 5.3.11-1A
BVPS-1 RCS Depressurization
Nuclear Power versus Time



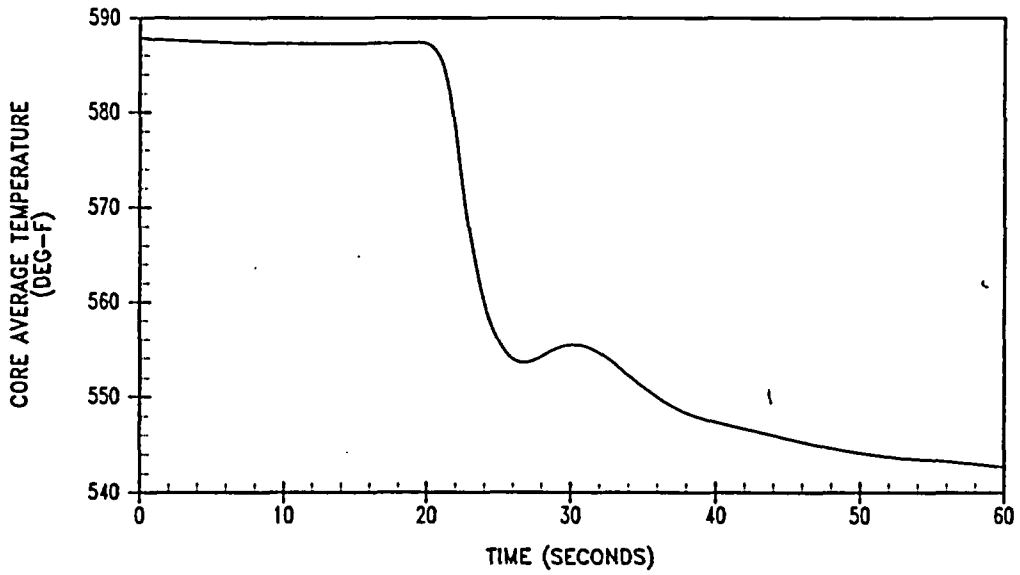


Figure 5.3.11-2A
BVPS-1 RCS Depressurization
Pressurizer Pressure and Core Average Temperature versus Time

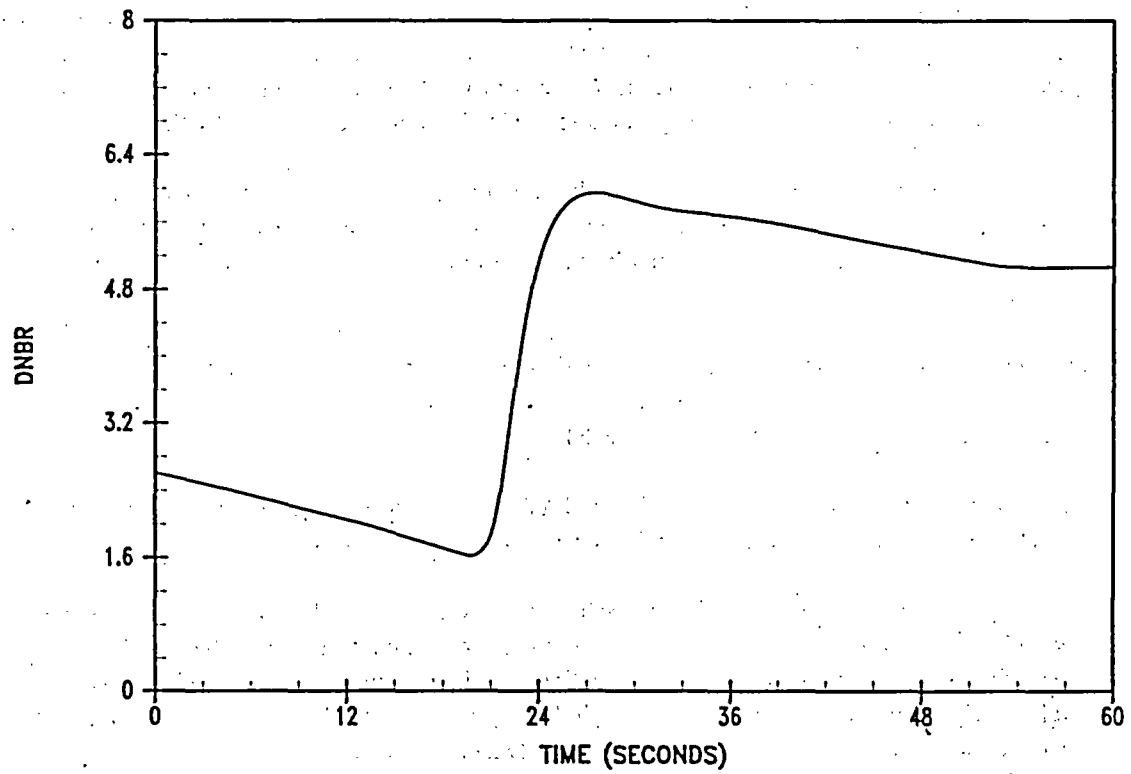


Figure 5.3.11-3A
BVPS-1 RCS Depressurization
DNBR versus Time

5.3.12 Major Rupture of a Main Steam Pipe

5.3.12.1 Identification of Causes and Accident Description

The steam release arising from a major rupture of a main steam pipe will result in an initial increase in steam flow that decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of reactor coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a positive reactivity insertion and subsequent reduction in core shutdown margin. If the most-reactive RCCA is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam pipe rupture is a concern primarily because of the high power peaking factors that would exist assuming the most-reactive RCCA to be stuck in its fully withdrawn position. The core is ultimately shut down by boric acid injection delivered by the ECCS.

The major rupture of a main steam pipe is the most-limiting cooldown transient. It is analyzed at hot zero power conditions with no decay heat (decay heat would retard the cooldown, thus reducing the return to power). A detailed discussion of this transient with the most limiting break size (a double-ended rupture) is presented below.

The following functions provide the necessary protection to mitigate a steam pipe rupture:

a. Actuation of the safety injection system (SIS)

b. The overpower reactor trips (neutron flux and ΔT), low pressurizer pressure reactor trip, and the reactor trip occurring in conjunction with receipt of the Safety Injection (SI) signal.

c. Redundant isolation of the main feedwater lines to prevent sustained high feedwater flow that would cause additional cooldown. In addition to the normal control action which will close the main feedwater control valves, a safety injection signal will rapidly close all feedwater control valves, trip the main feedwater pumps, and indirectly close the feedwater isolation valves that backup the control valves. A trip of the main feedwater pumps results in automatic closure of the respective pump discharge isolation valve.

d. Trip of the fast-acting Main Steamline Isolation Valves (MSIVs), assumed to occur in less than 8 seconds for BVPS-1 following initiation of any of the following signals:

- Low steamline pressure
- High negative steam pressure rate in any loop
- High-2 containment pressure

For any break (in any location), no more than one steam generator would experience an uncontrolled blowdown even if one of the MSIVs fails to close. For breaks downstream of the MSIVs, closure of all MSIVs will completely terminate the blowdown of all steam generators. The MSIVs are signal-actuated valves that close to prevent flow in the normal (forward) flow direction. The valves on all three steam lines are closed to isolate the other steam generators. Thus, only one steam generator can blow down, minimizing the potential steam release and resultant RCS cooldown. The remaining two steam generators

would still be available for dissipation of decay heat after the initial transient is over. In the case assuming a loss of offsite power, the decay heat is removed to the atmosphere via the atmospheric relief valves that have been sized to handle this accident scenario.

Following blowdown of the faulted steam generator, the unit can be brought to a stabilized hot standby condition through control of the auxiliary feedwater flow and SI flow as described by plant operating procedures. The operating procedures would call for operator action to limit RCS pressure and pressurizer level by terminating SI flow and to control steam generator level and RCS coolant temperature using the AFWS.

5.3.12.2 Input Parameters and Assumptions

The following summarizes the major input parameters and/or assumptions used in the main steam line rupture event:

a. Hot zero power conditions were modeled with and without offsite power available.

b. For BVPS-1, a 1.4 ft^2 break was analyzed for the Model 54F RSGs since they are designed with a flow restrictor built into the steam exit nozzle. The assumed steam generator tube plugging level is 0%.

c. For BVPS-1, separate cases were analyzed assuming unisolatable steam paths that could potentially occur after receiving a steam line isolation signal and achieving full closure of the MSIVs. The piping for the atmospheric steam dumps, the residual heat release valve supply line, and the supply line for the turbine-driven auxiliary feedwater pump branch off of the main steam line upstream of the MSIVs. These lines may not be isolated as a result of the steam line isolation signal.

d. All control rods are inserted except the most reactive RCCA, which is assumed to be stuck out of the core.

e. The shutdown margin is 1.77% $\Delta k/k$.

5.3.12.3 Description of Analysis

A detailed analysis using the LOFTRAN (Reference 1) computer code is performed in order to determine the plant transient conditions following a main steam line break. The code models the core neutron kinetics, RCS, pressurizer, steam generators, safety injection system and the auxiliary feedwater system; and computes pertinent variables, including the core heat flux, RCS temperature and pressure. A conservative selection of those conditions are then used to develop core models which provide input to the detailed thermal and hydraulic digital computer code, VIPRE (Reference 2), to determine if the DNB design basis is met.

5.3.12.4 Acceptance Criteria and Results

A major break in a steam system pipe is classified as an ANS Condition IV event. Minor secondary system pipe breaks are classified as ANS Condition III events. All of these events are analyzed to meet Condition II criteria.

The only criterion that may be challenged during this event is the one that states that the critical heat flux should not be exceeded. The analysis demonstrates that this criterion is met by showing that the minimum DNBR does not go below the limit value at any time during the transient.

For BVPS-1, the most limiting main steamline rupture case is the case in which offsite power is assumed to be available.

The calculated sequence of events for the most limiting case is shown in Table 5.3.12-1A for BVPS-1.

Figures 5.3.12-1A through 5.3.12-5A show the transient results for the most limiting case for BVPS-1. These figures show transient results following a main steamline rupture (complete severance of a pipe) at initial no-load conditions with offsite power available. Since offsite power is assumed available, full reactor coolant flow exists.

Should the core be critical at near zero power when the rupture occurs, the initiation of SI via a low steam line pressure signal will trip the reactor. Steam release from more than one steam generator will be prevented by automatic trip of the fast acting isolation valves in the steam lines by high containment pressure signals or by low steam line pressure signals. The steamline isolation valves are assumed to fully close in less than 8 seconds for BVPS-1 from initiation of an isolation signal.

As shown in Figure 5.3.12-4A for BVPS-1, the core attains criticality with the RCCAs inserted (i.e., with the plant shutdown assuming one stuck RCCA) before boron solution from the ECCS enters the RCS.

A DNB analysis was performed for the limiting point in the transient which determined that the DNB design basis is met.

5.3.12.5 Conclusions

The results of the major rupture of a main steam pipe event indicate that the DNB design basis is met. Therefore, this event does not adversely affect the core or the RCS, and all applicable acceptance criteria are met.

The results and conclusions of the analysis performed for the major rupture of a main steam pipe for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

5.3.12.6 References

1. Burnett, T.W.T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.

2. Sung, Y. X. et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), October 1999.

Table 5.3.12-1A
BVPS-1 Time Sequence of Events – Rupture of a Main Steam Pipe

Case	Event	Time (sec)
Reactor at hot zero power with offsite power available (Unisolatable steam release paths case)	Double-ended guillotine break occurs	0.0
	Low Steam Pressure SIS actuation setpoint reached	0.7
	MSIVs closed 8 seconds after SIS actuation signal	8.7
	High-head SI pump at rated speed 27 seconds after SIS actuation signal	27.7
	Main Feedwater flow isolated 30 seconds after SIS actuation signal	30.7
	Reactor becomes critical	32.4
	Time of minimum DNBR	359.4
	Power reaches maximum level	352.4
	Reactor returns subcritical	396.0

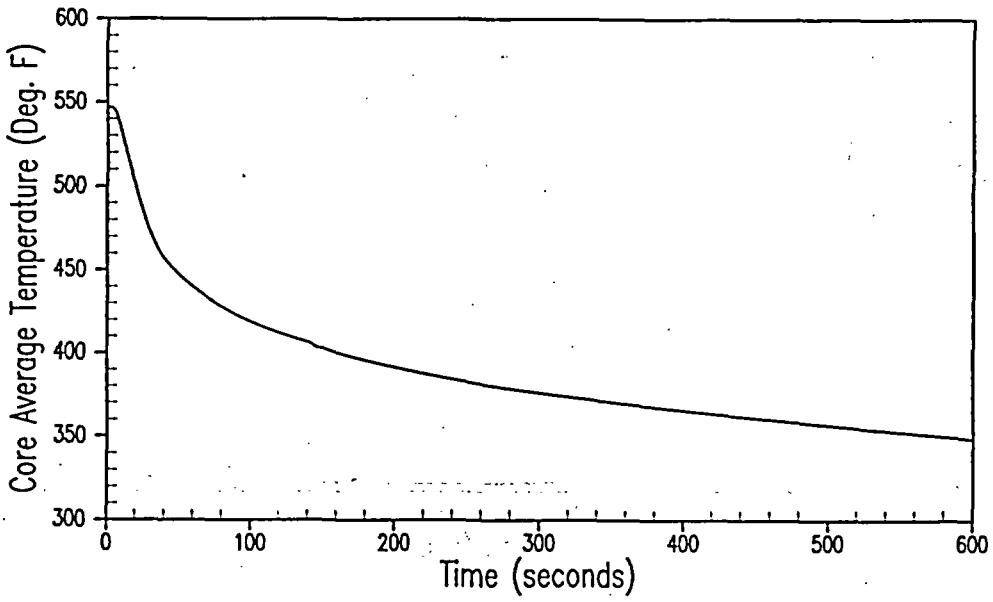


Figure 5.3.12-1A
BVPS-1
1.4 ft^2 Steamline Rupture at Hot Zero Power
(with Offsite Power Available, Unisolatable Steam Paths)
Core Average Temperature versus Time

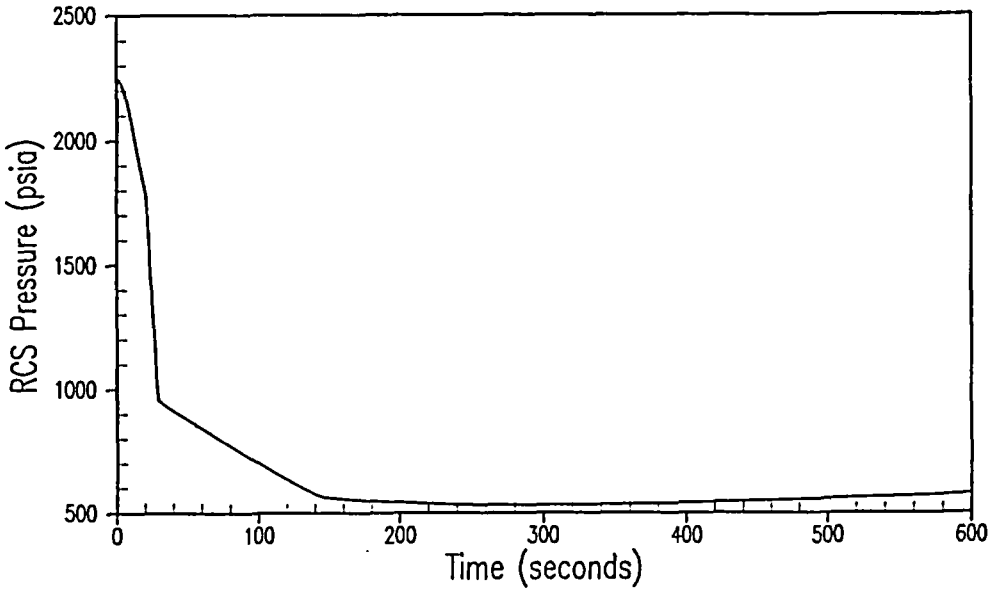


Figure 5.3.12-2A
BVPS-1
1.4 ft^2 Steamline Rupture at Hot Zero Power
(with Offsite Power Available, Unisolatable Steam Paths)
RCS Pressure versus Time

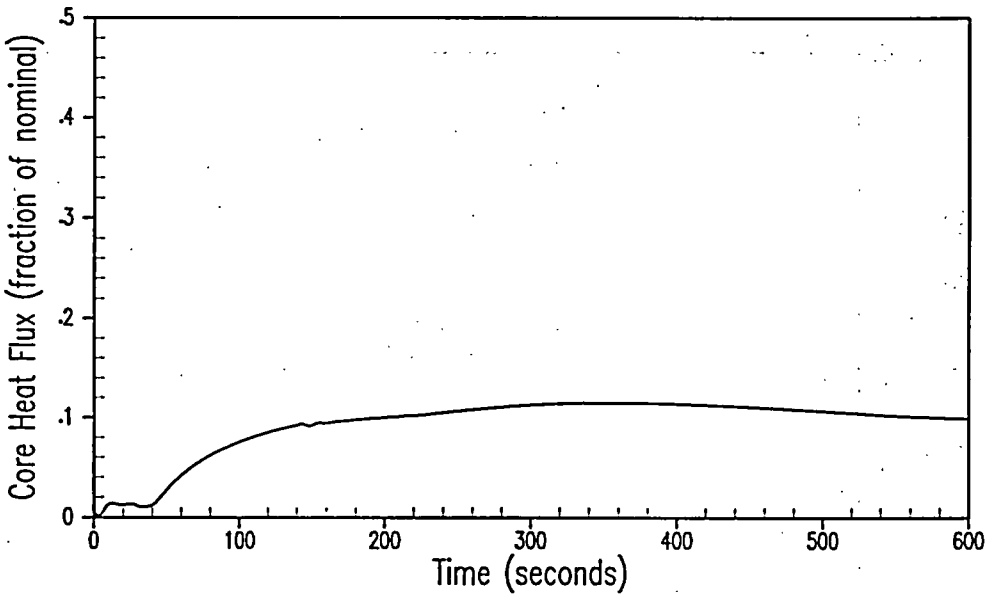


Figure 5.3.12-3A
BVPS-1
1.4 ft^2 Steamline Rupture at Hot Zero Power
(with Offsite Power Available, Unisolatable Steam Paths)
Core Heat Flux versus Time

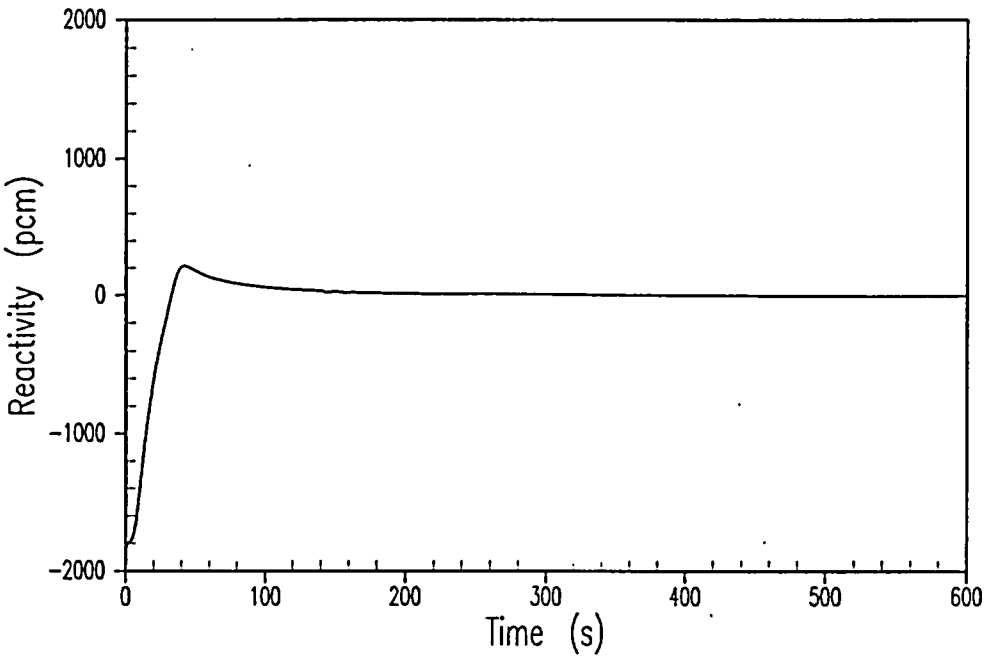


Figure 5.3.12-4A
BVPS-1
1.4 ft^2 Steamline Rupture at Hot Zero Power
(with Offsite Power Available, Unisolatable Steam Paths)
Reactivity versus Time

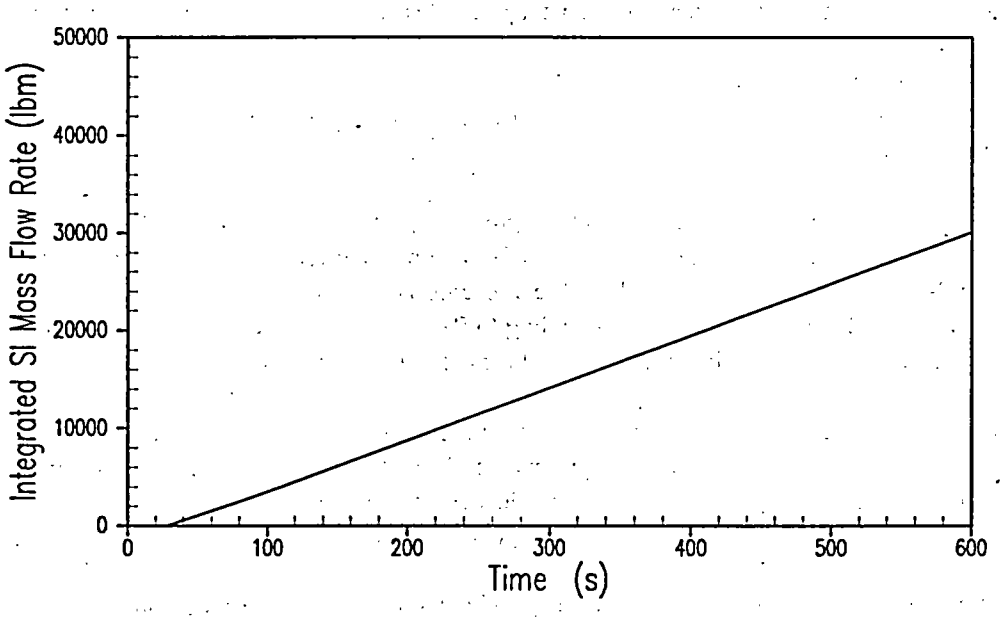


Figure 5.3.12-5A
BVPS-1
1.4 ft^2 Steamline Rupture at Hot Zero Power
(with Offsite Power Available, Unisolatable Steam Paths)
Integrated SI Flow Rate versus Time

5.3.13 Partial Loss of Forced Reactor Coolant Flow

5.3.13.1 Identification of Causes and Accident Description

A partial loss of forced coolant flow accident may result from a mechanical or electrical failure in a reactor coolant pump (RCP), or from a fault in the power supply to these pumps. If the reactor is at power at the time of the event, the immediate effect from the loss of forced coolant flow is a rapid increase in the coolant temperature. This increase in coolant temperature could result in a violation of the departure from nucleate boiling ratio (DNBR) limit, with subsequent fuel damage, if the reactor is not promptly tripped.

The following signals provide protection against a partial loss of forced reactor coolant flow incident:

- Low reactor coolant loop flow
- Undervoltage or underfrequency on reactor coolant pump power supply buses
- Pump circuit breaker opening

The reactor trip on low primary coolant loop flow provides protection against loss of flow conditions. This function is generated by two-out-of-three low flow signals per reactor coolant loop. Above Permissive P-8, low flow in any loop will actuate a reactor trip. Between approximately 10% power (Permissive P-7) and the power level corresponding to Permissive P-8, low flow in any two loops will actuate a reactor trip. Reactor trip on low flow is blocked below Permissive P-7.

The reactor trip on reactor coolant pump undervoltage is provided to protect against conditions which can cause a loss of voltage to all reactor coolant pumps, i.e., loss of offsite power. An RCP undervoltage reactor trip serves as an anticipatory backup to the low reactor coolant loop flow trip. The undervoltage trip function is blocked below approximately 10% power (Permissive P-7).

The reactor coolant pump underfrequency trip is provided to trip the reactor for an underfrequency condition resulting from frequency disturbances on the power grid. The RCP underfrequency reactor trip function is blocked below P-7. In addition, the underfrequency function will open all RCP breakers whenever an underfrequency condition occurs (no P-7 or P-8 interlock) to provide adequate RCP coastdown. This trip function also serves as an anticipatory backup to the low reactor coolant loop flow trip.

A reactor trip from pump breaker position is provided as a backup to the low flow signal. Above P-7, a breaker open signal from any two pumps will actuate a reactor trip. Reactor trip on reactor coolant pump breakers open is blocked below Permissive P-7.

5.3.13.2 Input Parameters and Assumptions

This accident is analyzed using the Revised Thermal Design Procedure (Reference 1). Initial core power is assumed to be at its nominal value consistent with steady-state, full-power operation. RCS pressure is at its nominal value for BVPS-1. RCS vessel average temperature is at its nominal value plus a 4.5°F bias. Uncertainties in initial conditions are included in the departure from nucleate boiling ratio (DNBR) limit value as described in Reference 1.

A conservatively large absolute value of the Doppler only power coefficient is used. A moderator temperature coefficient of 0 pcm/°F is assumed since this results in the maximum core power and hot spot heat flux during the initial part of the transient when the minimum DNBR is reached.

Normal reactor control systems and engineered safety systems (e.g., Safety Injection) are not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

The effects of asymmetric RCS flow (maximum loop-to-loop flow asymmetry of 5%) on the Partial Loss of Flow transient was also evaluated.

5.3.13.3 Description of Analysis

A partial loss of flow involving the loss of one reactor coolant pump with three loops in operation was analyzed.

The transient was analyzed using three digital computer codes. First, the LOFTRAN code (Reference 2) was used to calculate the loop and core flow transients, the nuclear power transient, and the primary system pressure and temperature transients. This code simulates a multiloop system, neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray, the steam generators, and main steam safety valves. The flow coastdown analysis performed by LOFTRAN is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, and the as-built pump characteristics, and is based on conservative system pressure loss estimates.

The FACTRAN code (Reference 3) was then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the VIPRE code (Reference 4) was used to calculate the DNBR during the transient based on the heat flux from FACTRAN and the flow from LOFTRAN. The DNBR results are based on the minimum of the typical and thimble cells.

5.3.13.4 Acceptance Criteria and Results

A partial loss of forced reactor coolant flow incident is classified by the American Nuclear Society (ANS) as a Condition II event. The immediate effect from a partial loss of forced reactor coolant flow is a rapid increase in the reactor coolant temperature and subsequent increase in reactor coolant system (RCS) pressure. The following three items summarize the criteria associated with this event:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the reactor coolant and main steam systems should be maintained below 110% of their respective design pressures.
- The peak linear heat generation rate should not exceed a value which would cause fuel centerline melt.

The partial loss of forced reactor coolant flow event is the least DNB-limiting transient among all of the loss of flow cases. Reactor trip for the partial loss of flow case occurs on a loop low flow signal. The VIPRE (Reference 4) analysis for this scenario confirmed that the minimum DNBR acceptance criterion is met. Fuel clad damage criteria are not challenged in the partial loss of forced reactor coolant flow case since the DNB criterion is met.

The analysis of the partial loss of flow event also demonstrates that the peak Reactor Coolant System and Main Steam System pressures are well below their respective limits.

The transient results for this case are presented in Figures 5.3.13-1A through 5.3.13-4A for BVPS-1. The sequence of events for this case is presented in Table 5.3.13-1.

5.3.13.5 Conclusions

The analysis performed for the EPU demonstrates that, for the partial loss of flow incident, the DNBR does not decrease below the safety analysis limit value at any time during the transient; thus, no fuel or clad damage is predicted. The peak primary and secondary system pressures remain below their respective limits at all times. All applicable acceptance criteria are therefore met.

The protection features presented in Section 5.3.13.1 provide mitigation for the partial loss of forced reactor coolant flow transient such that the above criteria are satisfied.

The results and conclusions of the analysis performed for the partial loss of forced reactor coolant flow for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt. Furthermore, the results and conclusions of this analysis will be confirmed on a cycle specific basis as part of the normal reload process.

5.3.13.6 References

1. Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), April 1989.

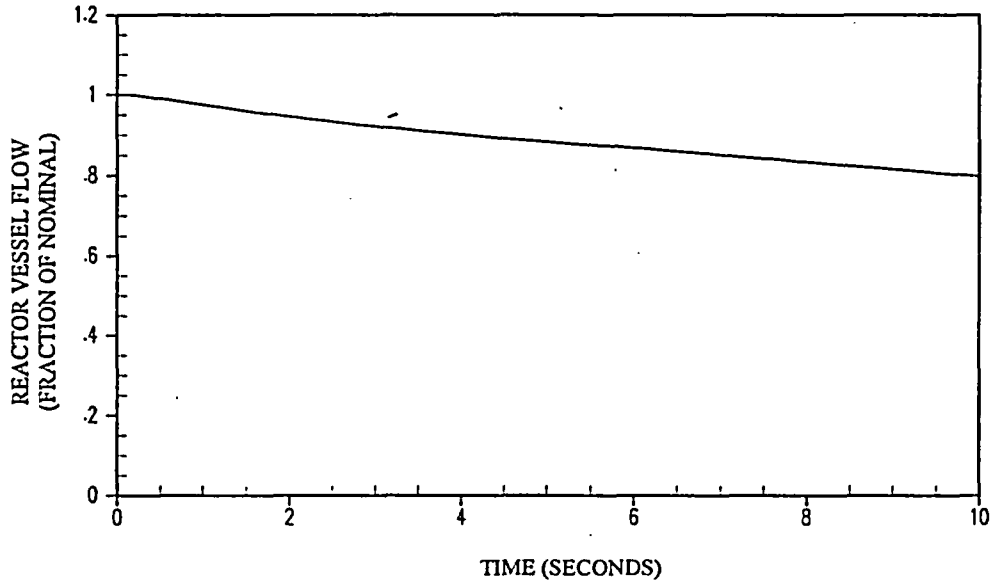
2. Burnett, T.W.T. et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.

3. Hargrove, H. G., "FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO2 Fuel Rod," WCAP-7908-A, December 1989.

4. Sung, Y. X. et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), October 1999.

Table 5.3.13-1
Time Sequence of Events – Partial Loss of Forced Reactor Coolant Flow

Case	Event	Unit 1 Time (sec)	Unit 2 Time (sec)
Three loops operating, one pump coasting down	Coastdown begins	0.0	NA
	Low flow reactor trip	1.6	NA
	Rods begin to drop	2.6	NA
	Minimum DNBR occurs	3.7	NA



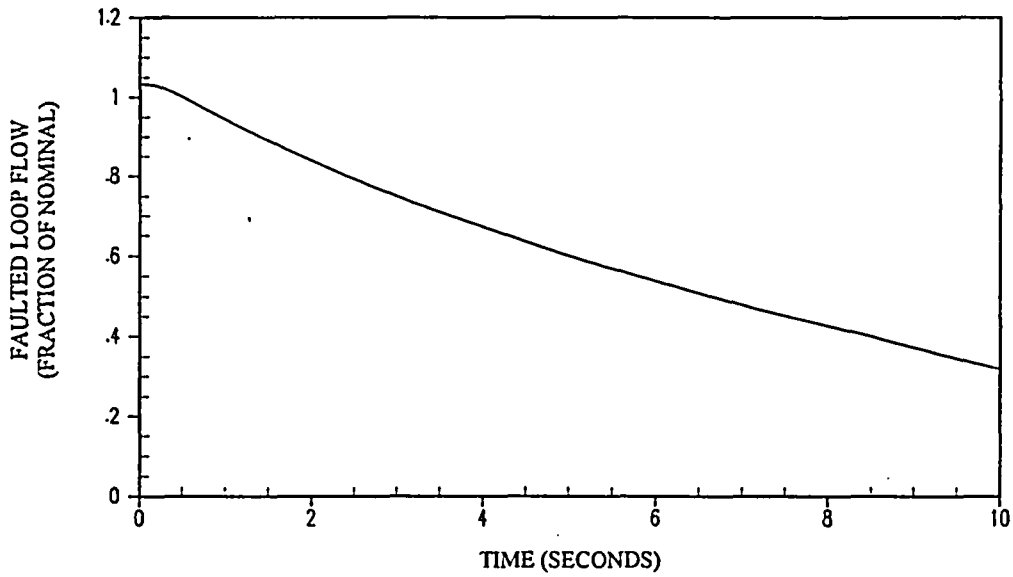
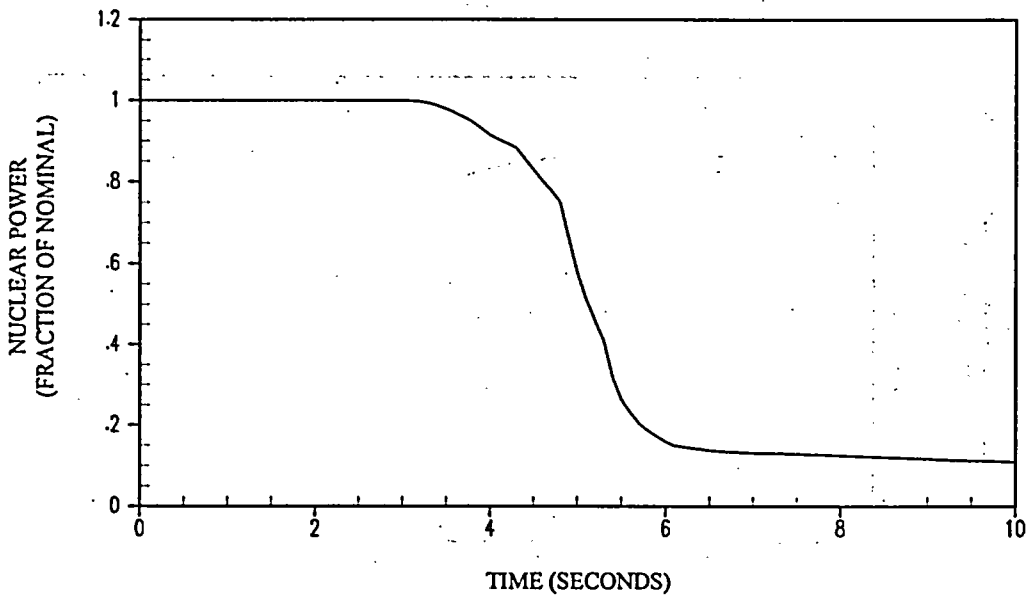


Figure 5.3.13-1A
BVPS-1 Partial Loss of Forced Reactor Coolant Flow
Reactor Vessel Flow and Faulted Loop Flow versus Time



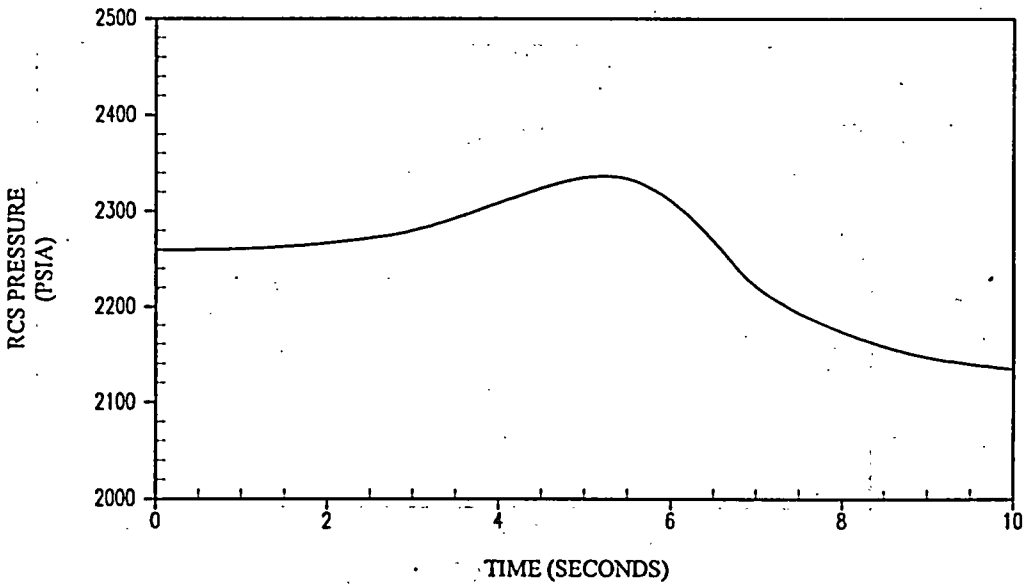
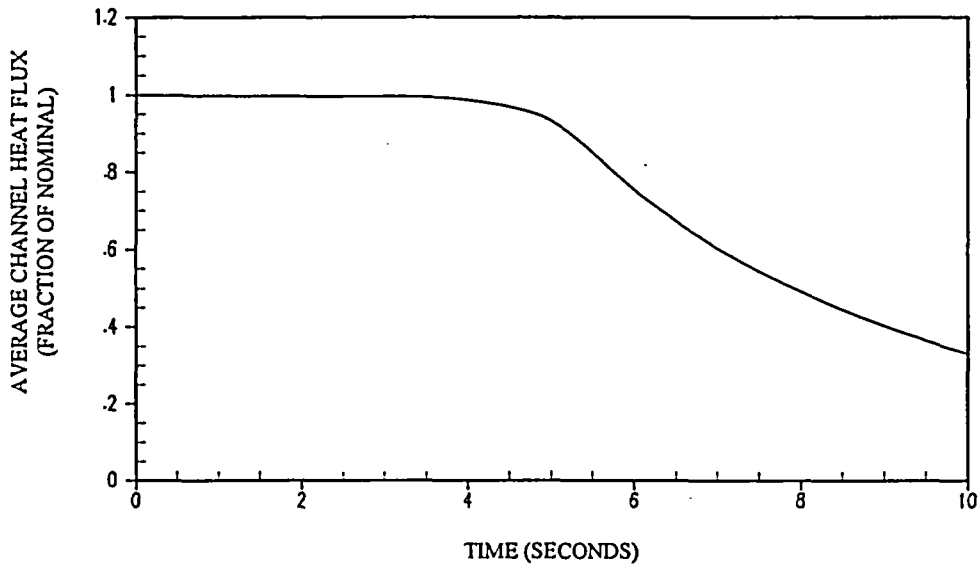


Figure 5.3.13-2A
BVPS-1 Partial Loss of Forced Reactor Coolant Flow
Nuclear Power and RCS Pressure versus Time



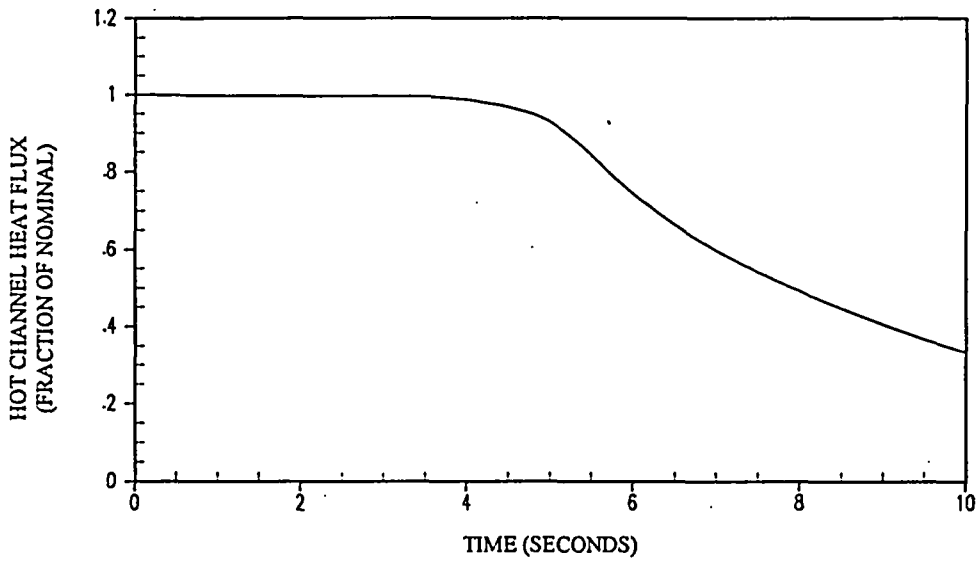


Figure 5.3.13-3A
BVPS-1 Partial Loss of Forced Reactor Coolant Flow
Average Channel and Hot Channel Heat Flux versus Time

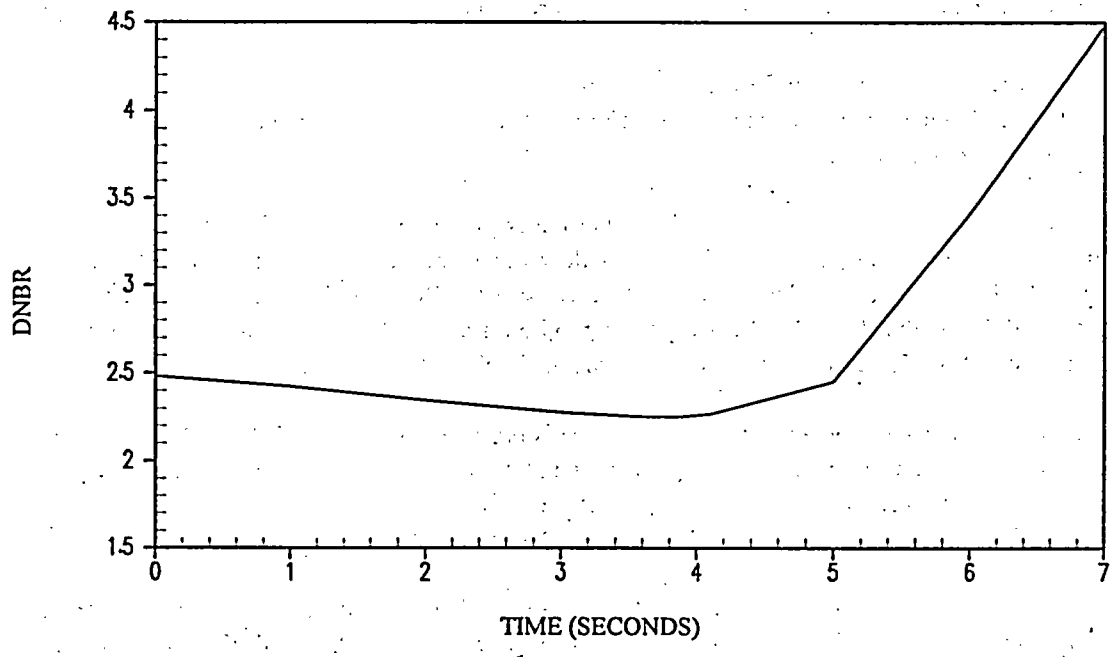


Figure 5.3.13-4A
BVPS-1 Partial Loss of Forced Reactor Coolant Flow
DNBR versus Time

5.3.14 Complete Loss of Forced Reactor Coolant Flow

5.3.14.1 Identification of Causes and Accident Description

A complete loss of forced coolant flow accident may result from a simultaneous loss of electrical power supply or a reduction in power supply frequency to all of the reactor coolant pumps (RCPs). If the reactor is at power at the time of the event, the immediate effect from the loss of forced coolant flow is a rapid increase in the coolant temperature. This increase in coolant temperature could result in a violation of the departure from nucleate boiling ratio (DNBR) limit, with subsequent fuel damage, if the reactor is not promptly tripped.

The following signals provide protection against a complete loss of forced reactor coolant flow incident:

- Low reactor coolant loop flow
- Undervoltage or underfrequency on reactor coolant pump power supply buses
- Pump circuit breaker opening

The reactor trip on low primary coolant loop flow provides protection against loss of flow conditions. This function is generated by two-out-of-three low flow signals per reactor coolant loop. Above Permissive P-8, low flow in any loop will actuate a reactor trip. Between approximately 10% power (Permissive P-7) and the power level corresponding to Permissive P-8, low flow in any two loops will actuate a reactor trip. Reactor trip on low flow is blocked below Permissive P-7.

The reactor trip on reactor coolant pump undervoltage is provided to protect against conditions which can cause a loss of voltage to all reactor coolant pumps, i.e., loss of offsite power. An undervoltage reactor trip serves as an anticipatory backup to the low reactor coolant loop flow trip. The undervoltage trip function is blocked below approximately 10% power (Permissive P-7).

The reactor coolant pump underfrequency reactor trip is provided to trip the reactor for an underfrequency condition resulting from frequency disturbances on the power grid. The RCP underfrequency reactor trip function is blocked below P-7. In addition, the underfrequency function will open all RCP breakers whenever an underfrequency condition occurs (no P-7 or P-8 interlock) to provide adequate RCP coastdown. This trip function also serves as an anticipatory backup to the low reactor coolant loop flow trip.

A reactor trip from pump breaker position is provided as a backup to the low flow signal. Above P-7, a breaker open signal from any two pumps will actuate a reactor trip. Reactor trip on reactor coolant pump breakers open is blocked below Permissive P-7.

5.3.14.2 Input Parameters and Assumptions

This accident is analyzed using the Revised Thermal Design Procedure (Reference 1). Initial core power is assumed to be at its nominal value consistent with steady-state, full-power operation. RCS pressure is at its nominal value for BVPS-1. RCS vessel average temperature is at its nominal value plus a 4.5°F bias. Uncertainties in initial conditions are included in the departure from nucleate boiling ratio (DNBR) limit value as described in Reference 1.

A conservatively large absolute value of the Doppler only power coefficient is used. The analysis also assumes a conservatively large moderator temperature coefficient (MTC) of zero pcm/°F at hot full power conditions. This results in the maximum core power and hot spot heat flux during the initial part of the transient when the minimum DNBR is reached.

Normal reactor control systems and engineered safety systems (e.g., Safety Injection) are not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

5.3.14.3 Description of Analysis

The following complete loss of forced reactor coolant flow cases were analyzed:

1. Complete loss of all three reactor coolant pumps with three loops in operation
2. Frequency decay event resulting in a complete loss of forced reactor coolant flow

These transients were analyzed by three digital computer codes. First, the LOFTRAN code (Reference 2) was used to calculate the loop and core flow transients, the nuclear power transient, and the primary system pressure and temperature transients. This code simulates a multiloop system, neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray, the steam generators, and main steam safety valves. The flow coastdown analysis performed by LOFTRAN is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, and the as-built pump characteristics and is based on conservative system pressure loss estimates.

The FACTRAN code (Reference 3) was then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the VIPRE code (Reference 4) was used to calculate the DNBR during the transient based on the heat flux from FACTRAN and the flow from LOFTRAN. The DNBR results are based on the minimum of the typical and thimble cells.

5.3.14.4 Acceptance Criteria and Results

A complete loss of forced reactor coolant flow incident is classified by the American Nuclear Society (ANS) as a Condition III event; however, for conservatism, the incident is analyzed to Condition II criteria. The immediate effect from a complete loss of forced reactor coolant flow is a rapid increase in the reactor coolant temperature and subsequent increase in reactor coolant system (RCS) pressure. The following three items summarize the criteria associated with this event:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.

- Pressure in the reactor coolant and main steam systems should be maintained below 110% of their respective design pressures.

- The peak linear heat generation rate should not exceed a value that would cause fuel centerline melt.

Both the Complete Loss of Flow and Frequency Decay cases are assumed to trip on a low reactor coolant loop flow signal. The VIPRE (Reference 4) analysis for these scenarios confirmed that the minimum DNBR acceptance criterion is met. Fuel clad damage criteria are not challenged in either of the complete loss of forced reactor coolant flow cases since the DNB criterion is met.

The analysis of the complete loss of flow event also demonstrates that the peak Reactor Coolant System and Main Steam System pressures are well below their respective limits.

The more limiting of these two cases in terms of the minimum calculated DNBR is the Frequency Decay case. The transient results for this case are presented in Figures 5.3.14-1A through 5.3.14-4A for BVPS-1. The sequence of events for both cases are presented in Table 5.3.14-1.

5.3.14.5 Conclusions

The analysis performed for the EPU demonstrates that, for the aforementioned complete loss of flow cases, the DNBR does not decrease below the safety analysis limit value at any time during the transients; thus, no fuel or clad damage is predicted. The peak primary and secondary system pressures remain below their respective limits at all times. All applicable acceptance criteria are therefore met.

The protection features presented in Section 5.3.14.1 provide mitigation for the complete loss of forced reactor coolant flow transients such that the above criteria are satisfied.

The results and conclusions of the analysis performed for the complete loss of forced reactor coolant flow for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt. Furthermore, the results and conclusions of this analysis will be confirmed on a cycle specific basis as part of the normal reload process.

5.3.14.6 References

1. Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), April 1989.

2. Burnett, T.W.T. et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.

3. Hargrove, H. G., "FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908-A, December 1989.

4. Sung, Y. X. et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), October 1999.

Table 5.3.14-1
Time Sequence of Events – Complete Loss of Forced Reactor Coolant Flow

Case	Event	BVPS-1 Time (sec)	BVPS-2 Time (sec)
Frequency Decay	Frequency decay begins	0.0	NA
	Low reactor coolant flow trip setpoint reached	1.7	NA
	Rods begin to drop	2.7	NA
	Minimum DNBR occurs	4.6	NA
	Maximum primary pressure occurs	5.9	NA
Complete Loss of Forced Reactor Coolant Flow	Flow coastdown begins	0.0	NA
	Low reactor coolant flow trip setpoint reached	1.6	NA
	Rods begin to drop	2.6	NA
	Minimum DNBR occurs	4.3	NA
	Maximum primary pressure occurs	5.5	NA

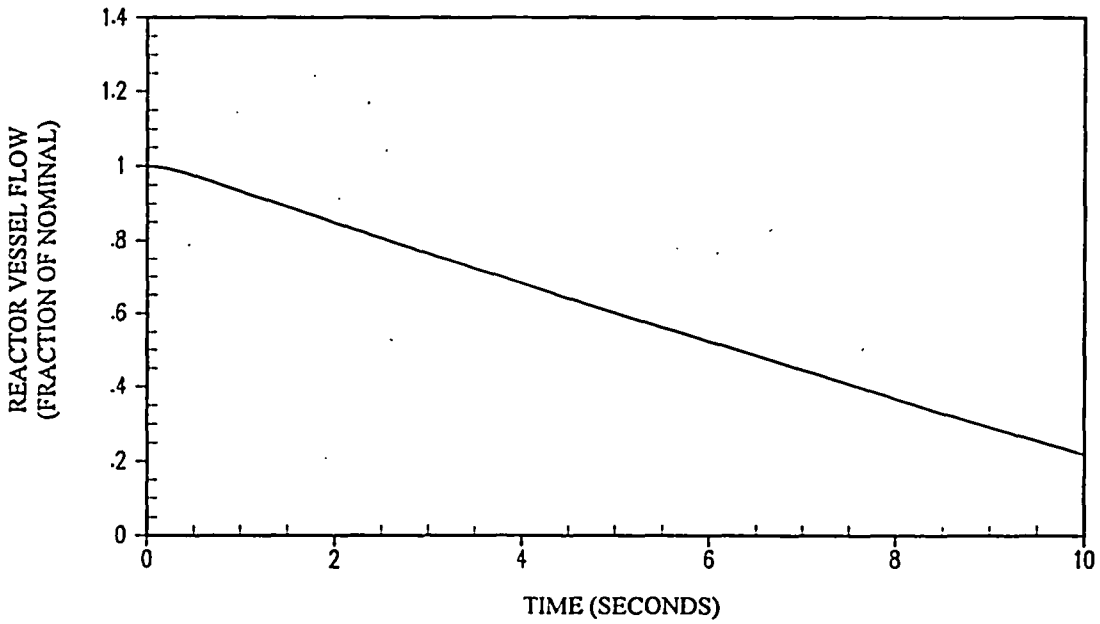
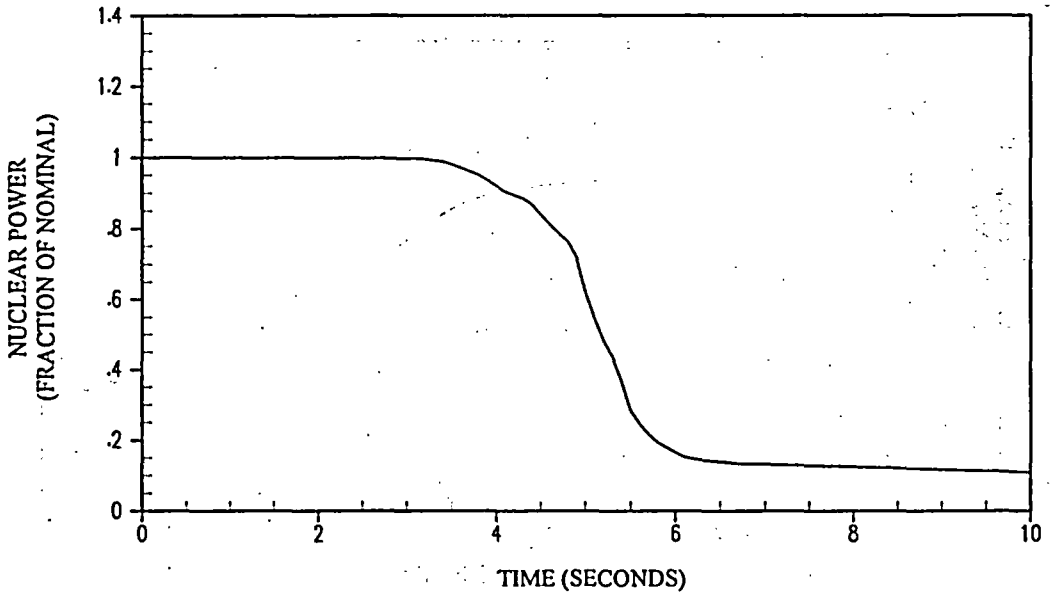


Figure 5.3.14-1A
BVPS-1 Complete Loss of Forced Reactor Coolant Flow – Frequency Decay
Reactor Vessel Flow versus Time



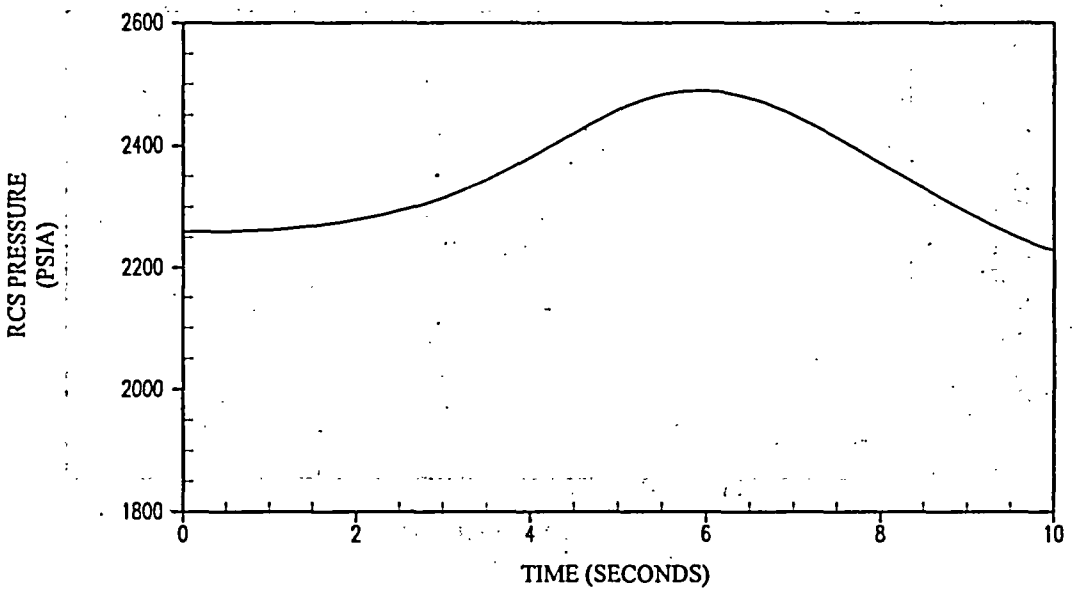
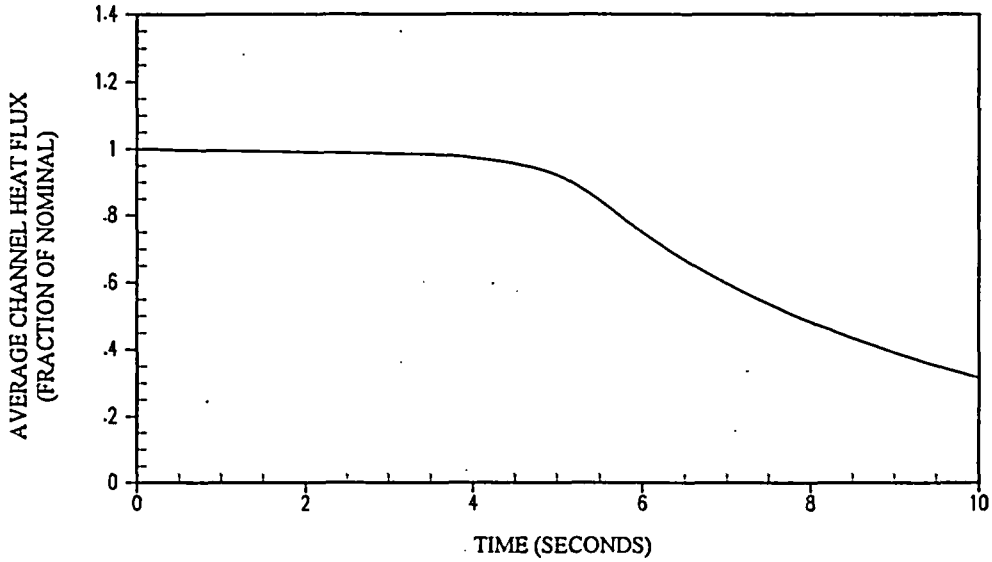


Figure 5.3.14-2A
BVPS-1 Complete Loss of Forced Reactor Coolant Flow – Frequency Decay
Nuclear Power and RCS Pressure versus Time



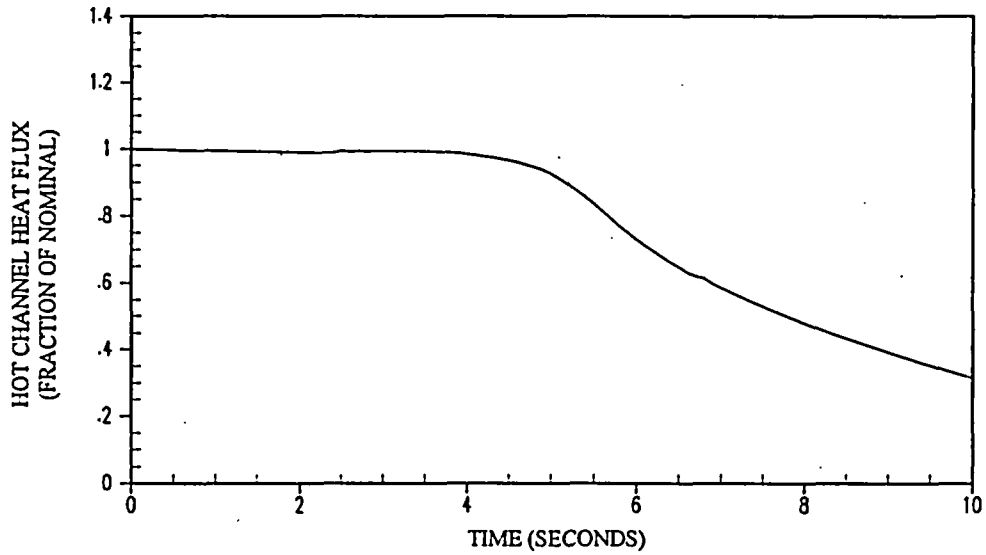


Figure 5.3.14-3A
BVPS-1 Complete Loss of Forced Reactor Coolant Flow – Frequency Decay
Average Channel and Hot Channel Heat Flux versus Time

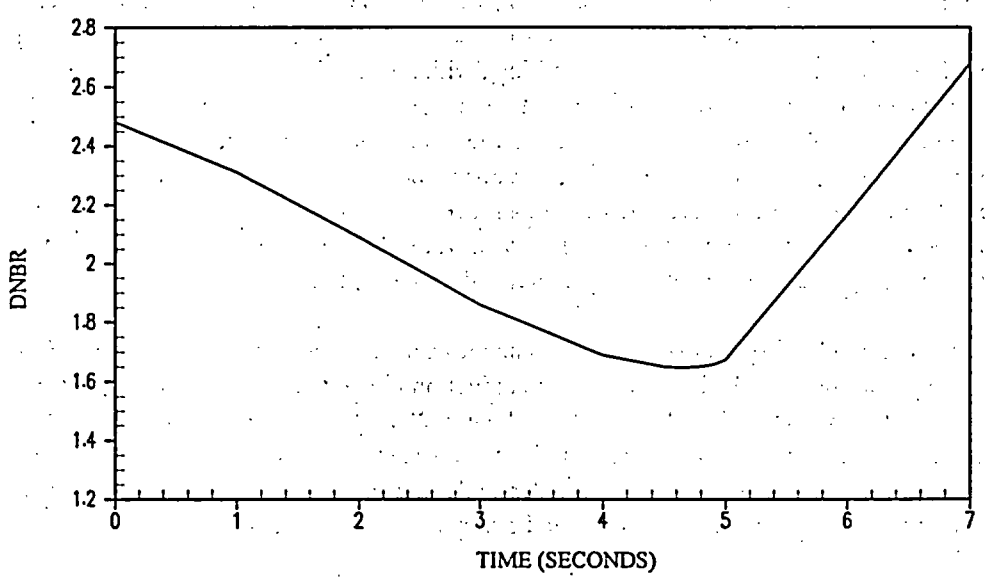


Figure 5.3.14-4A
BVPS-1 Complete Loss of Forced Reactor Coolant Flow – Frequency Decay
DNBR versus Time

5.3.15 Single Reactor Coolant Pump Locked Rotor

5.3.15.1 Identification of Causes and Accident Description

The event postulated is an instantaneous seizure of a reactor coolant pump (RCP) rotor or the sudden break of the shaft of the RCP. Flow through the affected reactor coolant loop is rapidly reduced, leading to initiation of a reactor trip on a low reactor coolant loop flow signal.

Following initiation of the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant causing the coolant to expand. At the same time, heat transfer to the shell side of the steam generators is reduced, first because the reduced flow results in a decreased tube-side film coefficient, and then because the reactor coolant in the tubes cools down while the shell-side temperature increases (turbine steam flow is reduced to zero upon plant trip due to turbine trip on reactor trip). The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam generators, causes an insurge into the pressurizer and a pressure increase throughout the Reactor Coolant System (RCS). The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the power-operated relief valves, and opens the pressurizer safety valves, in that sequence. The three power-operated relief valves are designed for reliable operation and would be expected to function properly during the event. However, for conservatism, their pressure-reducing effect, as well as the pressure-reducing effect of the spray, is not included in the analysis.

The consequences of a locked rotor (i.e., an instantaneous seizure of a pump shaft) are very similar to those of a pump shaft break. The initial rate of the reduction in coolant flow is slightly greater for the locked rotor event. However, with a broken shaft, the impeller could conceivably be free to spin in the reverse direction. The effect of reverse spinning is to decrease the steady-state core flow when compared to the locked rotor scenarios. The analysis considers only one scenario; it represents the most-limiting combination of conditions for the locked rotor and pump shaft break events.

5.3.15.2 Input Parameters and Assumptions

Two cases are evaluated in the analysis. Both assume one locked rotor/shaft break with a total of three loops in operation. The first case maximizes the RCS pressure transient. This is done using the Standard Thermal Design Procedure. Initial core power, reactor coolant temperature, and pressure are assumed to be at their maximum values consistent with full-power conditions including allowances for calibration and instrument errors. This assumption results in a conservative calculation of the coolant insurge into the pressurizer, which in turn results in a maximum calculated peak RCS pressure..

The second case is an evaluation of DNB in the core during the transient. This case is analyzed using the Revised Thermal Design Procedure (Reference 1). Initial core power is assumed to be at its nominal value consistent with steady-state, full-power operation. RCS pressure is at its nominal value for BVPS-1. RCS vessel average temperature is at its nominal value plus a 4.5°F bias. Uncertainties in initial conditions are included in the departure from nucleate boiling ratio (DNBR) limit value as described in Reference 1.

Both the RCS pressure case and the DNB case assume a zero moderator temperature coefficient (MTC) and a conservatively large (absolute value) Doppler-only power coefficient. The negative reactivity from control rod insertion/scram for both cases is based on 4.0% Δk/k trip reactivity from HFP.

Normal reactor control systems and engineered safety systems (e.g., Safety Injection) are not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

The effects of asymmetric RCS flow (maximum loop-to-loop flow asymmetry of 5%) on the Locked Rotor transients were also evaluated.

5.3.15.3 Description of Analysis

The following locked rotor/shaft break cases were analyzed:

1. Peak RCS pressure resulting from a locked rotor/shaft break in one-of-three loops
2. Number of rods-in-DNB resulting from a locked rotor/shaft break in one-of-three loops

The pressure case is analyzed using two digital computer codes. The LOFTRAN code (Reference 2) is used to calculate the resulting loop and core flow transients following the pump seizure, the time of reactor trip based on the loop flow transients, the nuclear power following reactor trip, and the peak RCS pressure. The reactor coolant flow coastdown analysis performed by LOFTRAN is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, the as-built pump characteristics, and is based on conservative system pressure loss estimates. The thermal behavior of the fuel located at the core hot spot is investigated using the FACTRAN code (Reference 3) which uses the core flow and the nuclear power values calculated by LOFTRAN. The FACTRAN code includes a film boiling heat transfer coefficient.

The case analyzed to evaluate core DNB uses LOFTRAN, FACTRAN and the VIPRE code (Reference 4). The LOFTRAN and FACTRAN codes are used in the same manner as in the pressure case. The VIPRE code is used to calculate the DNBR during the transient based on the heat flux from FACTRAN and the flow from LOFTRAN.

For the peak RCS pressure evaluation, the initial pressure is conservatively estimated to be 40 psi for BVPS-1 above the nominal pressure of 2250 psia to allow for initial condition uncertainties in the pressurizer pressure measurement and control channels. This is done to obtain the highest possible rise in the coolant pressure during the transient. To obtain the maximum pressure in the primary side, conservatively high loop pressure drops are added to the calculated pressurizer pressure. The pressure response reported in Table 5.3.15-1 is at the point in the RCS having the maximum pressure, i.e., at the outlet of the RCP in the faulted loop.

For a conservative analysis of fuel rod behavior, the hot spot evaluation assumes that DNB occurs at the initiation of the transient and continues throughout the event. This assumption reduces heat transfer to the coolant and results in conservatively high hot spot temperatures.

Evaluation of the Pressure Transient

No credit is taken for the pressure-reducing effect of the pressurizer power-operated relief valves, pressurizer spray, steam dump or controlled feedwater flow after plant trip. Although these systems are expected to function and would result in a lower peak pressure, an additional degree of conservatism is provided by not including their effect.

The pressurizer safety valve model includes a +3% valve tolerance plus 5 psi accumulation above the nominal setpoint of 2500 psia. An additional 1% setpoint shift as described in Reference 5 does not apply to BVPS-1. An additional delay (0.33 seconds for BVPS-1) is included to account for the time to purge the loop seals as discussed in Reference 5.

Evaluation of DNB in the Core During the Event

For this event, DNB is assumed to occur in the core; therefore, an evaluation of the consequences with respect to fuel rod thermal transients is performed. Results obtained from analysis of this "hot spot" condition represent the upper limit with respect to clad temperature and zirconium-water reaction. In the evaluation, the rod power at the hot spot conservatively considers an F_Q of 2.52. The number of rods-in-DNB are conservatively calculated for use in dose consequence evaluations.

Film Boiling Coefficient

The film boiling coefficient is calculated in the FACTRAN code (Reference 3) using the Bishop-Sandberg-Tong film boiling correlation. The fluid properties are evaluated at the film temperature (average between the wall and bulk temperatures). The program calculates the film coefficient at every time step based upon the actual heat transfer conditions at the time. The neutron flux, system pressure, bulk density, and mass flow rate as a function of time are used as program input.

For this analysis, the initial values of the pressure and the bulk density are used throughout the transient since they are the most conservative with respect to the clad temperature response. As indicated earlier, DNB was assumed to occur from the beginning of the transient.

Fuel Clad Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between the fuel and clad (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between the pellet and clad. For the initial portion of the transient, a high gap coefficient produces higher clad temperatures since the heat stored and generated in the fuel redistributes itself in the cooler cladding. Based on investigations on the effect of the gap coefficient upon the maximum clad temperature during the transient, the gap coefficient was assumed to increase from a steady-state value consistent with initial fuel temperatures to 10,000 Btu/hr-ft^2-°F at the initiation of the transient. Thus, the large amount of energy stored in the fuel is released to the clad at the initiation of the transient.

Zirconium-Steam Reaction

The zirconium-steam reaction can become significant above 1800°F (clad temperature). The Baker-Just parabolic rate equation (Reference 3) is used to define the rate of the zirconium-steam reaction.

The reaction heat is 1510 cal/g. The effect of zirconium-steam reaction is included in the calculation of the "hot spot" clad temperature transient.

5.3.15.4 Acceptance Criteria and Results

The RCP locked rotor accident is classified by the American Nuclear Society (ANS) as a Condition IV event. A RCP locked rotor results in a rapid reduction in forced reactor coolant loop flow that increases the reactor coolant temperature and subsequently causes the fuel cladding temperature and RCS pressure to increase. The following items summarize the criteria associated with this event:

- Fuel cladding damage, including melting, due to increased reactor coolant temperatures must be prevented. This is precluded by demonstrating that the maximum clad temperature at the core hot spot remains below 2700°F, and the zirconium-water reaction at the core hot spot is less than 16 weight percent.

- Pressure in the reactor coolant system should be maintained below that which would cause stresses to exceed the faulted condition stress limits (i.e., Service Level D). Note that since Service Level D requirements do not translate directly to a percentage of the design pressure, Service Level C requirements have been conservatively applied. This corresponds to 120% of the design pressure of 2500 psia or 2997 psia.

- Rods-in DNB (dose calculation) should be less than or equal to 20%.

With respect to the peak RCS pressure, peak clad temperature, zirconium-steam reaction, and maximum predicted rods-in-DNB, the analysis demonstrated that all applicable acceptance criteria are met. The calculated sequence of events is presented in Table 5.3.15-1 for the Locked Rotor event. The results of the calculations (peak pressure, peak clad temperature, and zirconium-steam reaction) are summarized in Table 5.3.15-2. The rods-in-DNB criterion of less than or equal to 20% has also been met. The transient results for the peak pressure/hot spot case are provided in Figures 5.3.15-1A through 5.3.15-4A for BVPS-1.

5.3.15.5 Conclusions

The analysis performed for the EPU demonstrates that, for the Locked Rotor event, the peak clad surface temperature calculated for the hot spot during the worst transient remains considerably less than 2700°F and the amount of zirconium-water reaction is small. Under such conditions, the core will remain in place and intact with no loss of core cooling capability.

The analysis also confirms that the peak RCS pressure reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits, and thereby, the integrity of the primary

coolant system is demonstrated. The rods-in-DNB design criterion is also met. Therefore, the conclusions presented in the UFSAR remain valid.

The protection features described in Section 5.3.15.1 provide mitigation for a locked rotor transient such that the above criteria are satisfied.

The results and conclusions of the analysis performed for the single reactor coolant pump locked rotor for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt. Furthermore, the results and conclusions of this analysis will be confirmed on a cycle specific basis as part of the normal reload process.

5.3.15.6 References

1. Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), April 1989.

2. Burnett, T.W.T. et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.

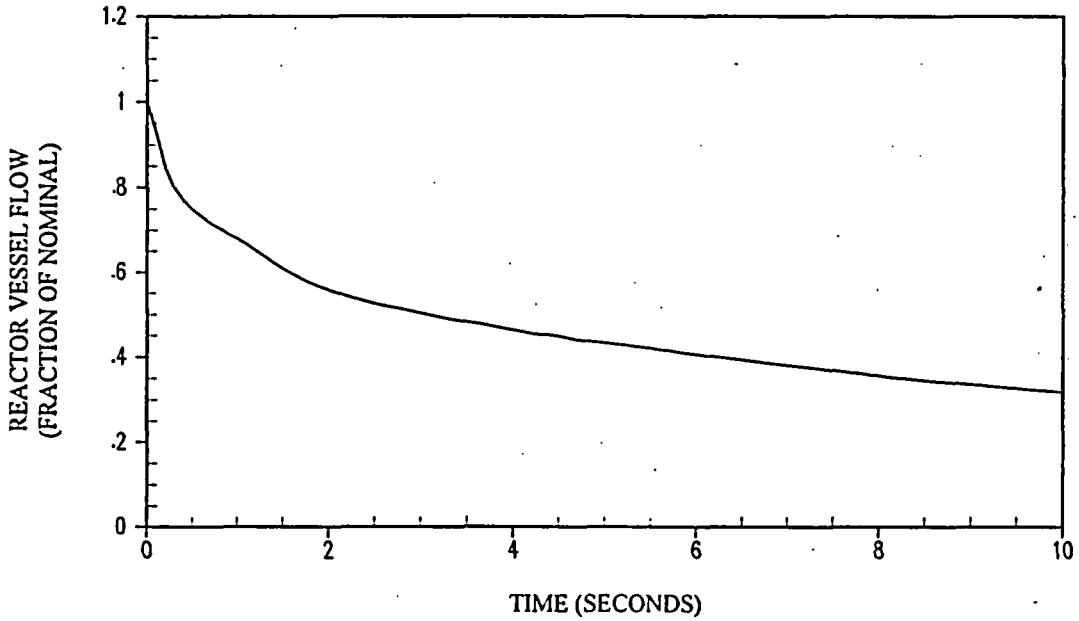
3. Hargrove, H. G., "FACTRAN -- A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908-A, December 1989.

4. Sung, Y. X. et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), October 1999.

5. Barrett, G. O., et al., "Pressurizer Safety Valve Set Pressure Shift," WCAP-12910, March 1991.

Table 5.3.15-1 Time Sequence of Events – Single RCP Locked Rotor		
Event	BVPS-1 Time (sec)	BVPS-2 Time (sec)
Rotor on one pump locked or the shaft breaks	0.0	NA
Low flow reactor trip setpoint reached	0.04	NA
Rods begin to drop	1.04	NA
Remaining pumps lose power and begin to coastdown	1.04	NA
Maximum RCS pressure occurs	3.0	NA
Maximum clad average temperature occurs	3.8	NA
Time of maximum clad oxidation	10.0	NA

Table 5.3.15-2 Summary of Results for Single RCP Locked Rotor			
Criteria	BVPS-1 3 Loops Initially Operating, One Locked Rotor	BVPS-2 3 Loops Initially Operating, One Locked Rotor	Limit
Maximum Clad Temperature at Core Hot Spot, °F	1868	NA	2700
Maximum Zr-H_2O Reaction at Core Hot Spot, wt. %	0.41	NA	16.0
Maximum RCS Pressure, psia	2716	NA	2997



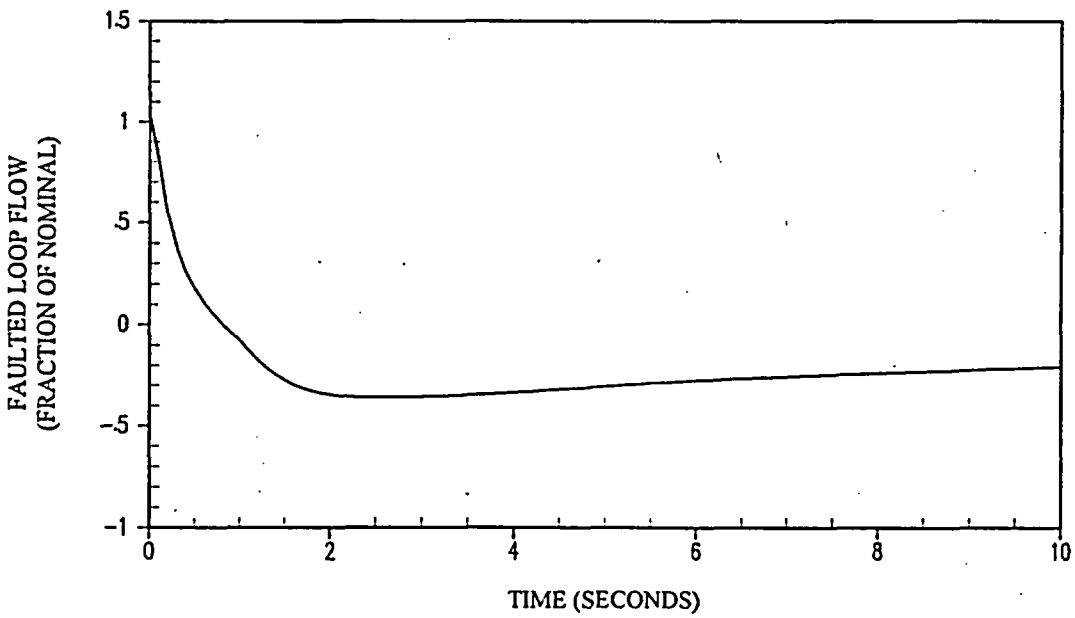
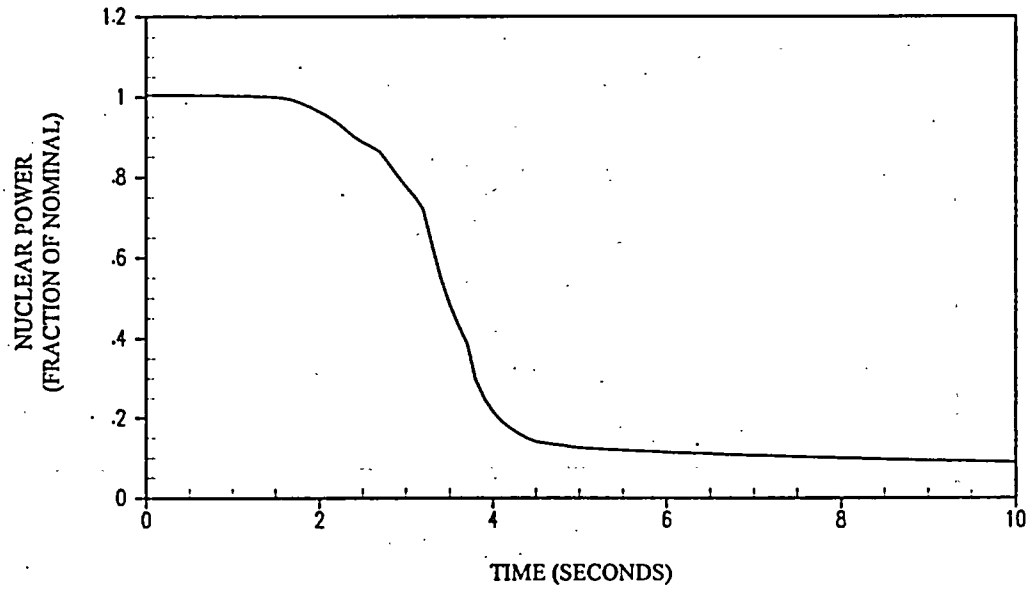


Figure 5.3.15-1A
BVPS-1 Single Reactor Coolant Pump Locked Rotor
Reactor Vessel Flow and Faulted Loop Flow versus Time



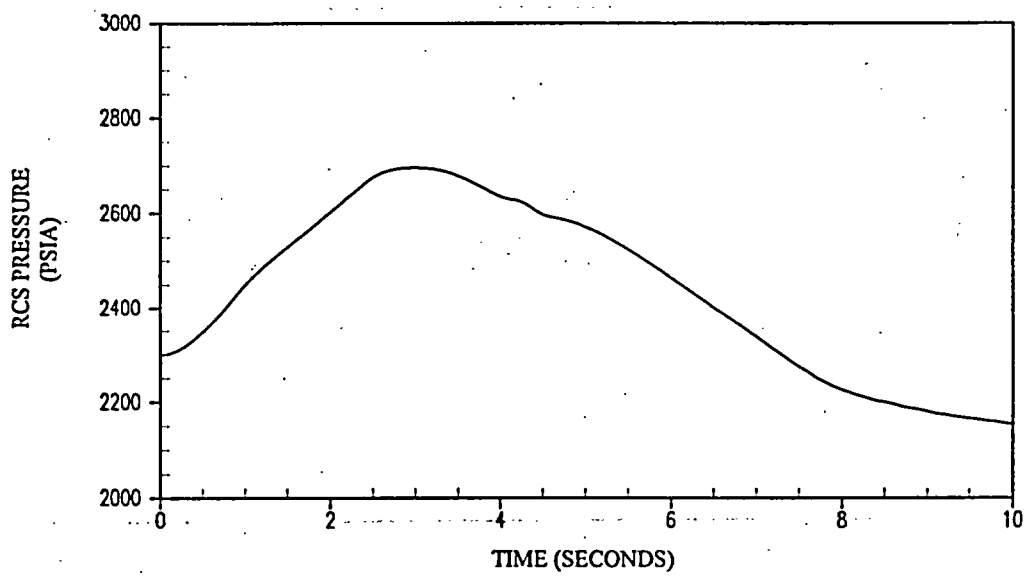
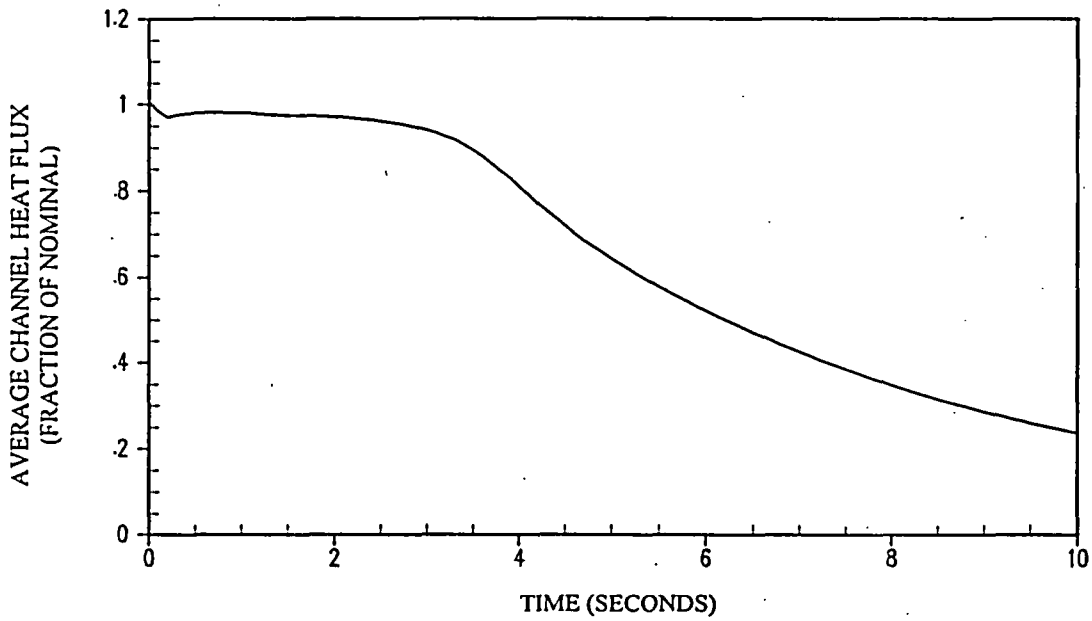


Figure 5.3.15-2A
BVPS-1 Single Reactor Coolant Pump Locked Rotor
Nuclear Power and RCS Pressure versus Time



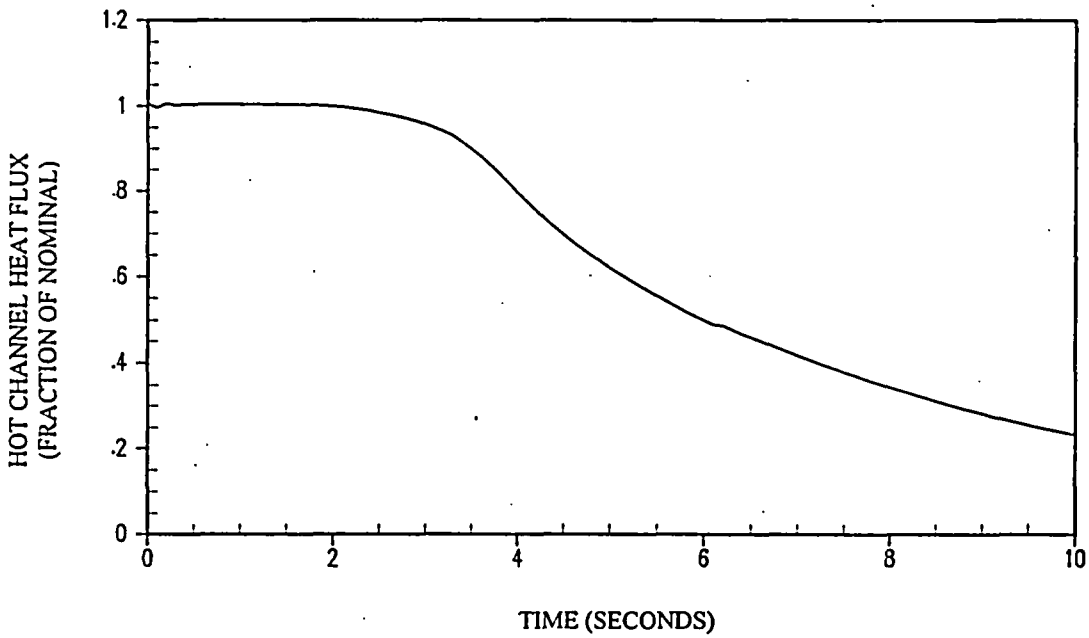
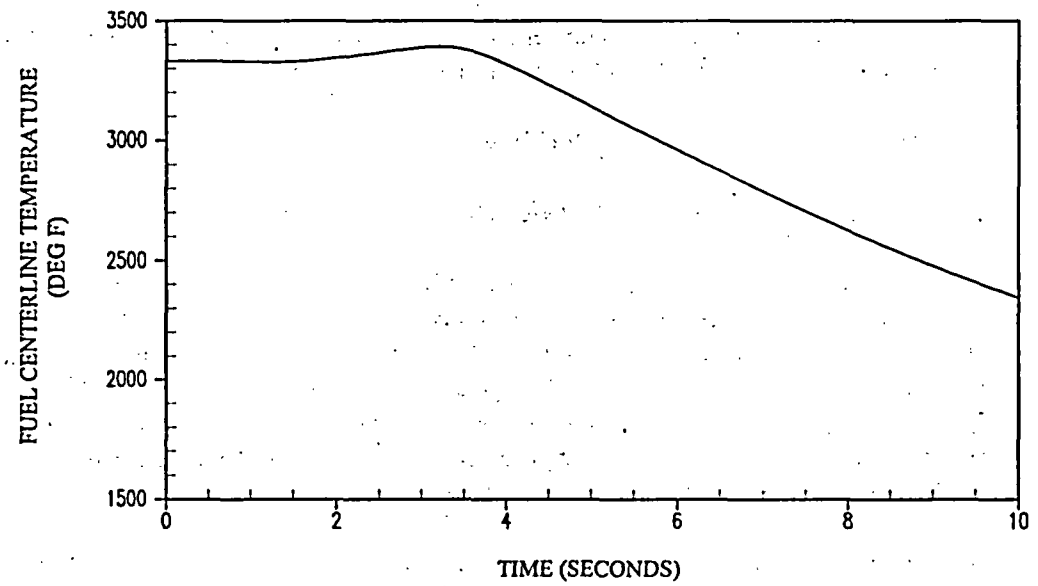


Figure 5.3.15-3A
BVPS-1 Single Reactor Coolant Pump Locked Rotor
Average Channel and Hot Channel Heat Flux versus Time



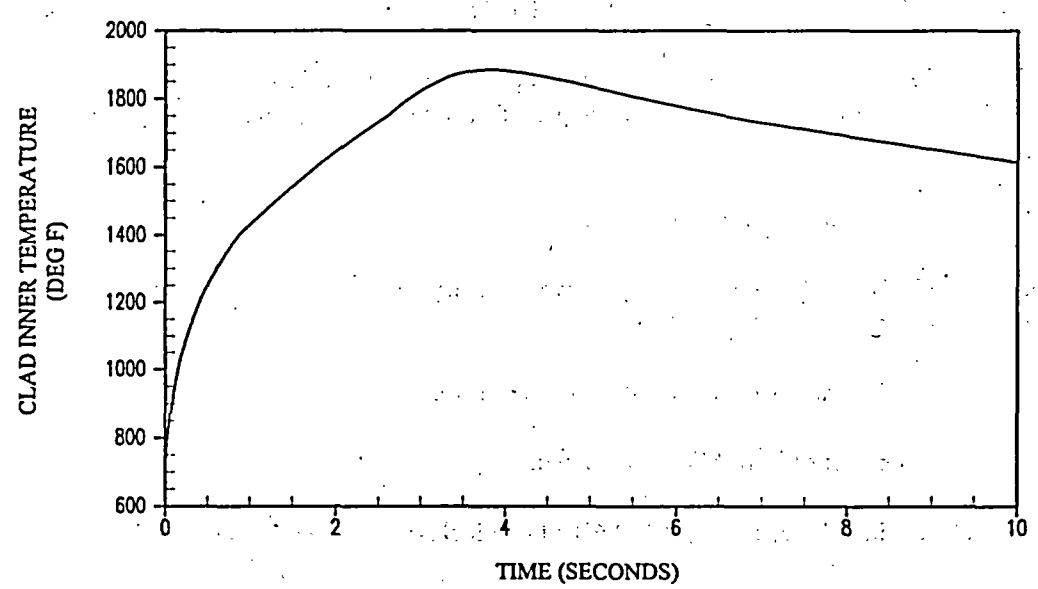


Figure 5.3.15-4A
BVPS-1 Single Reactor Coolant Pump Locked Rotor
Fuel Centerline and Clad Inner Temperatures versus Time

5.3.16 Rupture of a Control Rod Drive Mechanism Housing Rod Cluster Control Assembly Ejection (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.3.17 Major Rupture of a Main Feedwater Pipe

5.3.17.1 Identification of Causes and Accident Description

A major feedwater line rupture is defined as a break in a feedwater pipe large enough to prevent the addition of sufficient feedwater to the steam generators to maintain shell-side fluid inventory in the steam generators. If the break is postulated in a feedline between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. Further, a break in this location could preclude the subsequent addition of auxiliary feedwater to the affected steam generator. A break upstream of the feedline check valve would affect the NSSS only as a loss of feedwater. This case is covered by the loss of normal feedwater analysis presented in Section 5.3.7.

Depending upon the size of the break and the plant operating conditions at the time of the rupture, the break could either cause an RCS heatup or cooldown. The potential RCS cooldown resulting from a secondary pipe rupture is evaluated in the Steamline Break analysis presented in BVPS-1 UFSAR Section 14.2.5.1. Only the RCS heatup effects of a feedline rupture are presented in this section.

A feedline rupture reduces the ability to remove heat generated by the core from the RCS. The Auxiliary Feedwater System is provided to ensure that adequate feedwater will be available to provide decay heat removal.

5.3.17.2 Input Parameters and Assumptions

In support of the EPU, feedline rupture analyses were performed to demonstrate that the feedline rupture acceptance criteria are met (see Section 5.3.17.4).

Several key assumptions are made in the analysis. These are:

- EPU NSSS power of 2910 MWt is assumed.
- The plant is initially operating at 100.6% of nominal NSSS power (1.006 x 2910 MWt).
- The Model 54F replacement steam generators (RSGs) are analyzed for BVPS-1.
- The initial RCS average temperature is 8.5°F above the nominal value to account for initial condition uncertainties and loop-to-loop temperature asymmetry.
- The initial RCS pressure is 40 psi for BVPS-1 below its nominal value to account for initial condition uncertainties.

- Initial pressurizer level is at the nominal full power programmed value plus 7% to account for initial condition uncertainties.

- Initial steam generator water level is at the nominal value plus 10% for BVPS-1 in the faulted steam generator and at the nominal value minus 10% for BVPS-1 in the intact steam generators to account for initial condition uncertainties.

- Main feedwater flow to all steam generators is assumed to be lost at the time the break occurs (all main feedwater spills out through the break).

- The full double-ended main feedwater pipe break is assumed. A break size of 0.922 ft^2 was analyzed for BVPS-1 with Model 54F RSGs.

- The single failure assumption is conservatively set as highest capacity auxiliary feedwater pump (i.e., turbine driven) and one train of SI. SI does not significantly influence the analysis results.

- PORVs are assumed to be available.

- Reactor trip is assumed to be actuated when the steam generator low-low level trip setpoint is reached in the ruptured steam generator. A conservative setpoint of 0% NRS is modeled.

- The following auxiliary feedwater flow assumption is made: 250 gpm of AFW is split equally to two intact SGs prior to isolation of the faulted generator; after manual isolation of the faulted SG, 400 gpm of AFW is split equally to two intact SGs.

- An operator action time of 15 minutes to isolate the faulted SG is assumed.

- No credit is taken for heat energy deposited in the RCS metal during the RCS heatup.

- No credit is taken for charging or letdown.

- Steam generator heat transfer area is assumed to decrease as the shell-side liquid inventory decreases.

- Conservative feedwater line break discharge quality is assumed. This minimizes the heat transfer capability of the faulted steam generator.

- Conservative core residual heat generation is assumed based upon long-term operation at the initial power level preceding the trip.

- No credit is taken for the following potential protection logic signals to mitigate the consequences of the accident:

  a. High pressurizer pressure
  b. High pressurizer level
  c. High containment pressure

5.3.17.3 Description of Analysis

The transient response following a Feedwater Pipe Rupture event is calculated by a detailed digital simulation of the plant. The analysis models a simultaneous loss of main feedwater to all steam generators and subsequent reverse blowdown of the faulted steam generator. The analysis is performed using the LOFTRAN code (Reference 1), which simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The following four cases are analyzed for BVPS-1:

1. Case 1: RSGs, Maximum reactivity feedback, with offsite power, 0.922 ft^2 break
2. Case 2: RSGs, Maximum reactivity feedback, without offsite power, 0.922 ft^2 break
3. Case 3: RSGs, Minimum reactivity feedback, with offsite power, 0.922 ft^2 break
4. Case 4: RSGs, Minimum reactivity feedback, without offsite power, 0.922 ft^2 break

5.3.17.4 Acceptance Criteria and Results

The feedline rupture accident is an ANS Condition IV occurrence. Condition IV events are faults that are not expected to occur, but are postulated because their consequences would include the potential for release of significant amounts of radioactive material.

The specific criteria used in evaluating the consequences of the feedline rupture shall be:

- Pressure in the reactor coolant and main steam systems should be maintained below 110% of the design pressures.
- Any fuel damage that may occur during the transient should be of a sufficiently limited extent so that the core will remain in place and geometrically intact with no loss of core cooling capability.
- Any activity release must be such that the calculated doses at the site boundary are within 10 CFR 50.67.

To conservatively meet these basic criteria, the internal criterion established within Westinghouse is that no bulk boiling occurs in the primary coolant system following a feedline rupture prior to the time that the heat removal capability of the steam generators, being fed auxiliary feedwater, exceeds NSSS residual heat generation.

The results of the feedline rupture cases analyzed show that all acceptance criteria noted above have been met as follows:

- No bulk boiling occurs in the primary coolant system following a feedline rupture prior to the time that the heat removal capability of the steam generators, being fed auxiliary feedwater, exceeds NSSS residual heat generation.
- The RCS and MSS pressures remain below 110% of their respective design pressures.

For BVPS-1, the limiting case is feedline rupture with offsite power available, minimum reactivity feedback and a break size of 0.922 ft^2. The transient results for this case are presented in Figures 5.3.17-1A through 5.3.17-5A. The transient results for the corresponding BVPS-1 case without offsite power available are presented in Figures 5.3.17-6A through 5.3.17-10A. The time sequence of events for both cases are presented in Table 5.3.17-1A.

5.3.17.5 Conclusions

The results of the analyses performed for the EPU show that for the postulated feedwater line rupture, auxiliary feedwater system capacity is adequate to remove decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core.

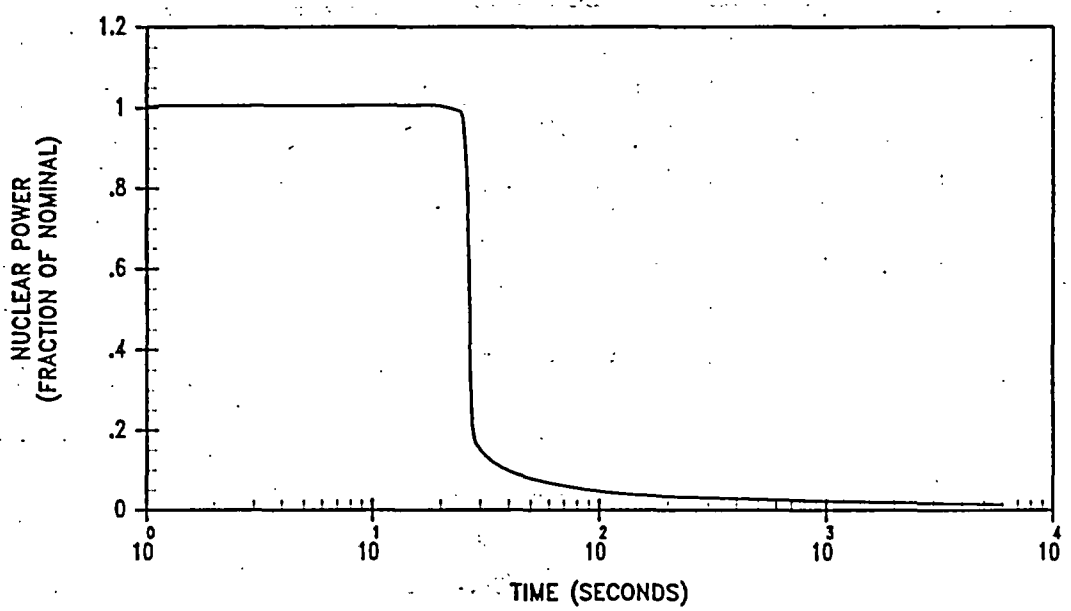
The results and conclusions of the analyses performed for the major rupture of a main feedwater pipe for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

5.3.17.6 References

1. Burnett, T.W.T. et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.

Table 5.3.17-1A
BVPS-1 Time Sequence of Events – Major Rupture of a Main Feedwater Pipe

Case	Event	Time (sec)
Feedline Rupture with offsite power available, Minimum reactivity feedback, Break size of 0.922 ft^2	Main feedline rupture occurs	10.0
	Low steamline pressure setpoint reached in ruptured steam generator	19.0
	Low-low steam generator water level reactor trip setpoint reached in ruptured steam generator	22.0
	Rods begin to drop	24.0
	All main steamline isolation valves close	27.0
	First steam generator safety valve setpoint reached in an intact steam generator	35.6
	Auxiliary feedwater is started	79.0
	Feedwater lines are purged and "cold" auxiliary feedwater is delivered to intact steam generators	804.0
	Hot and Cold Leg temperatures begin to decrease	~2900
Feedline Rupture without offsite power available, Minimum reactivity feedback, Break size of 0.922 ft^2	Main feedline rupture occurs	10.0
	Low steamline pressure setpoint reached in ruptured steam generator	19.0
	Low-low steam generator water level reactor trip setpoint reached in ruptured steam generator	22.0
	Rods begin to drop	24.0
	Reactor coolant pumps begin to coast down	26.0
	All main steamline isolation valves close	27.0
	First steam generator safety valve setpoint reached in an intact steam generator	36.0
	Auxiliary feedwater is started	79.0
	Feedwater lines are purged and "cold" auxiliary feedwater is delivered to intact steam generators	804.0
	Hot and Cold Leg temperatures begin to decrease	~1500



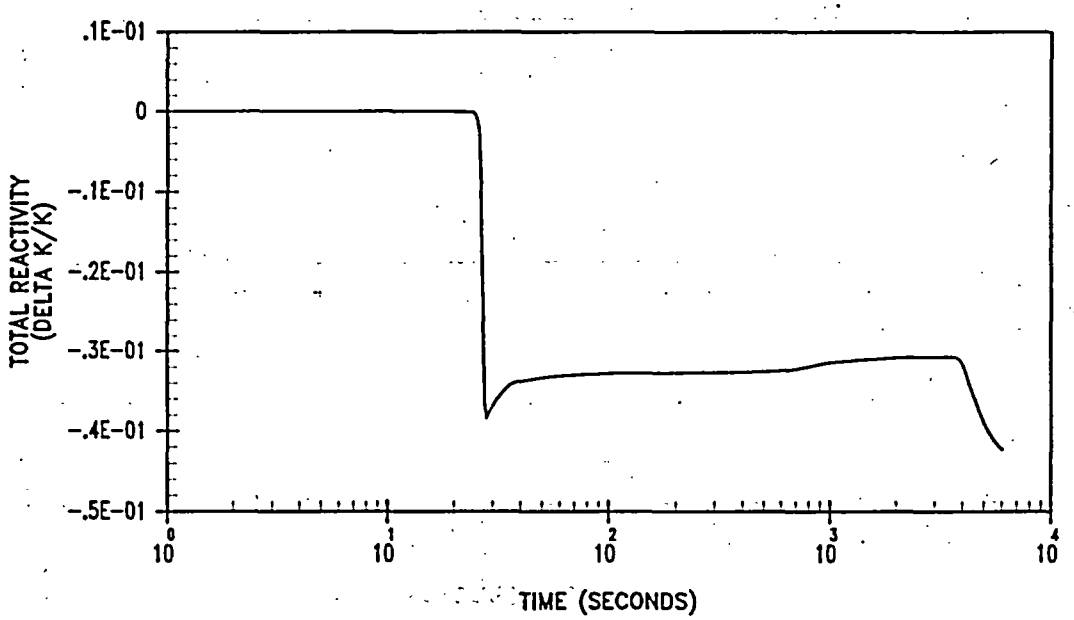
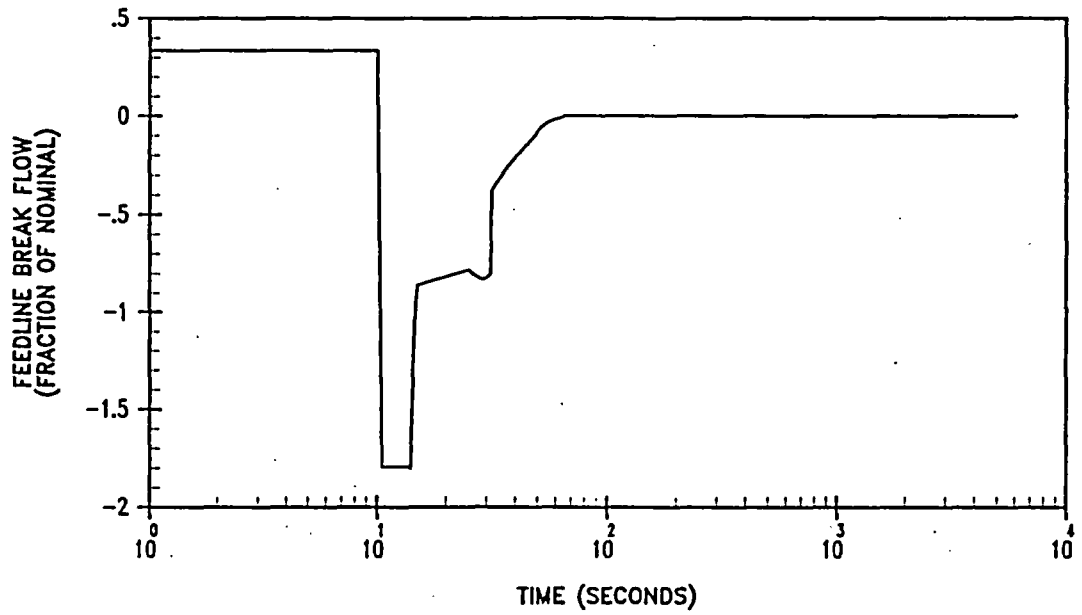


Figure 5.3.17-1A
BVPS-1 Feedline Rupture with Offsite Power Available
Nuclear Power and Total Reactivity versus Time



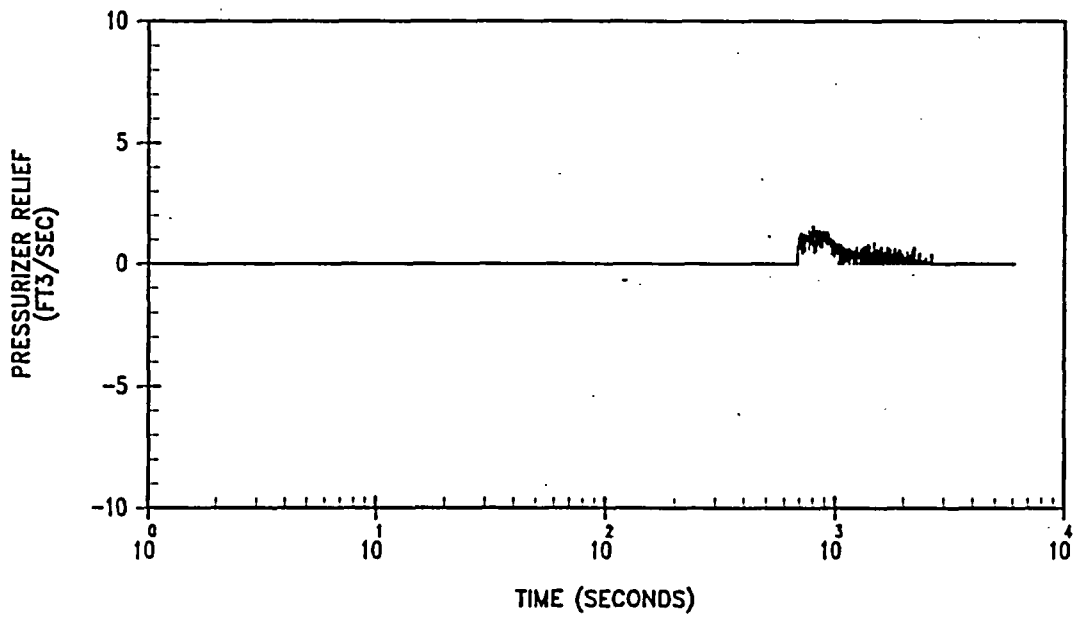
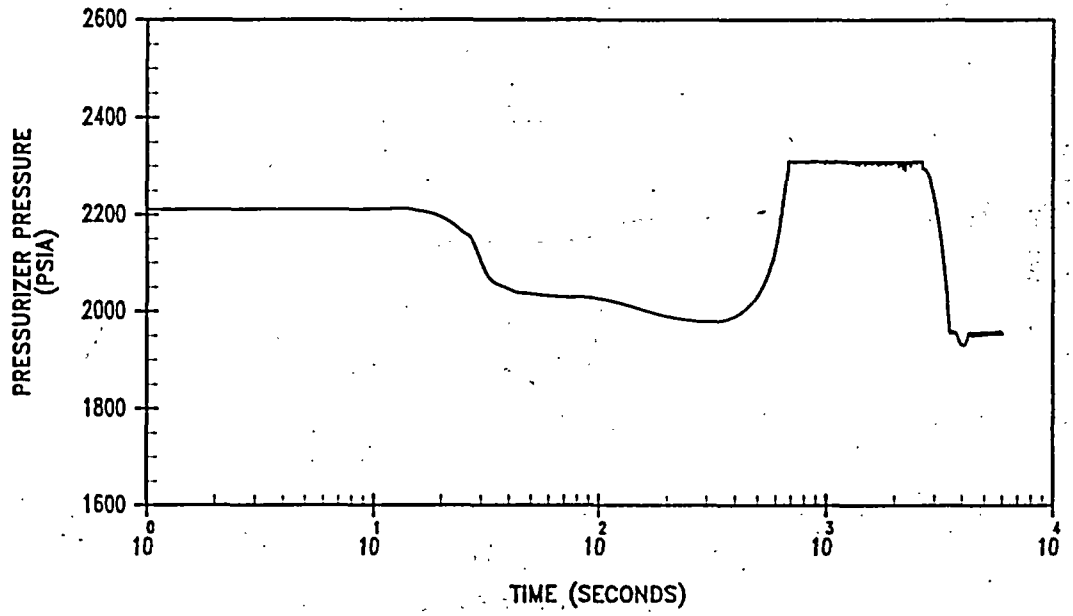


Figure 5.3.17-2A
BVPS-1 Feedline Rupture with Offsite Power Available
Feedline Break Flow and Pressurizer Relief versus Time



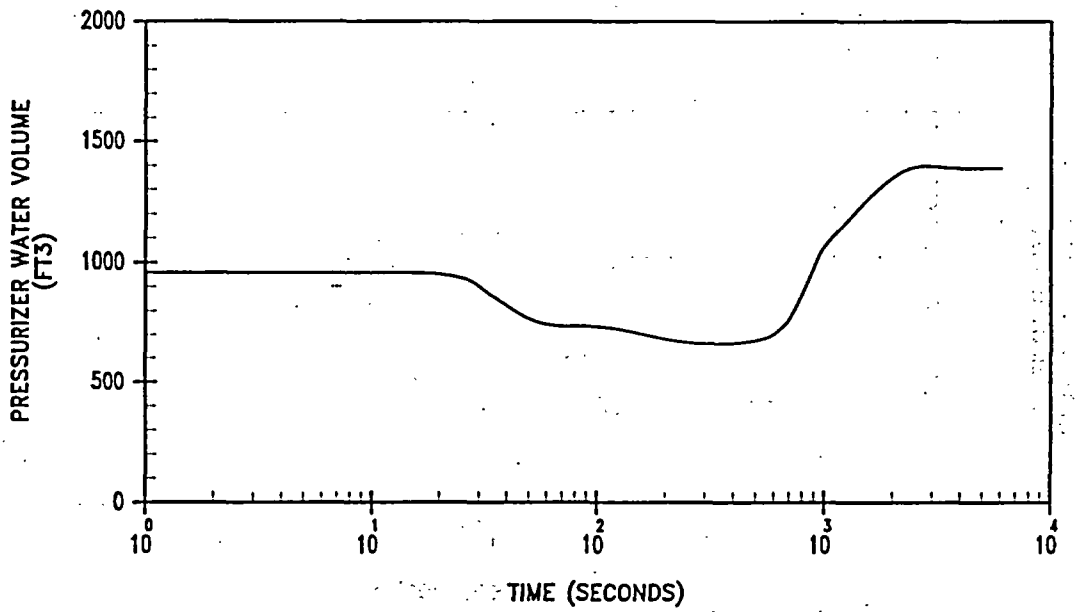
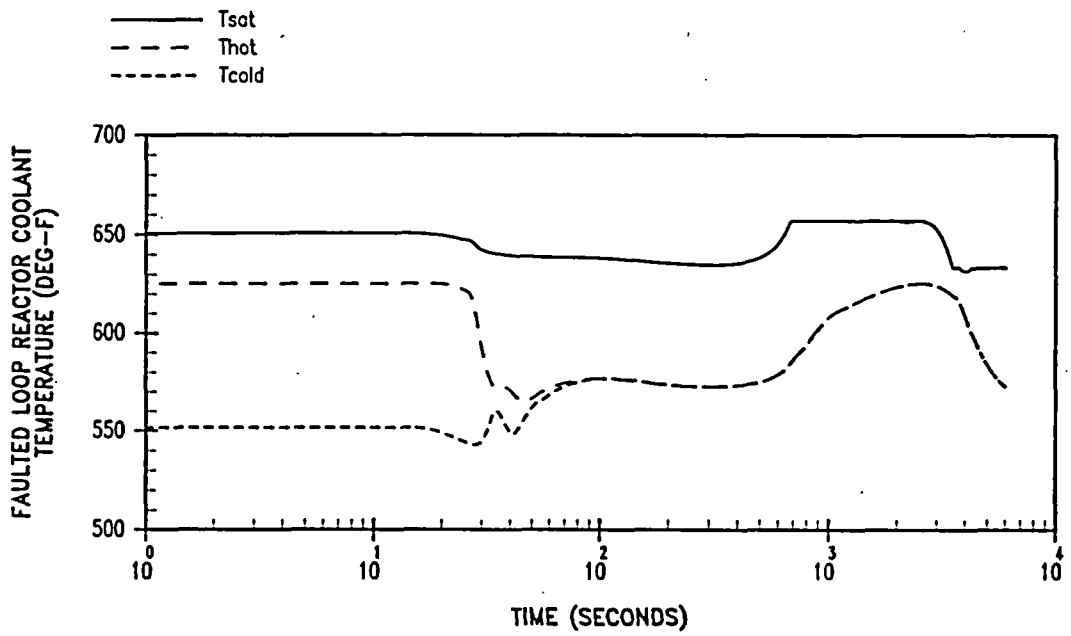


Figure 5.3.17-3A
BVPS-1 Feedline Rupture with Offsite Power Available
Pressurizer Pressure and Pressurizer Water Volume versus Time



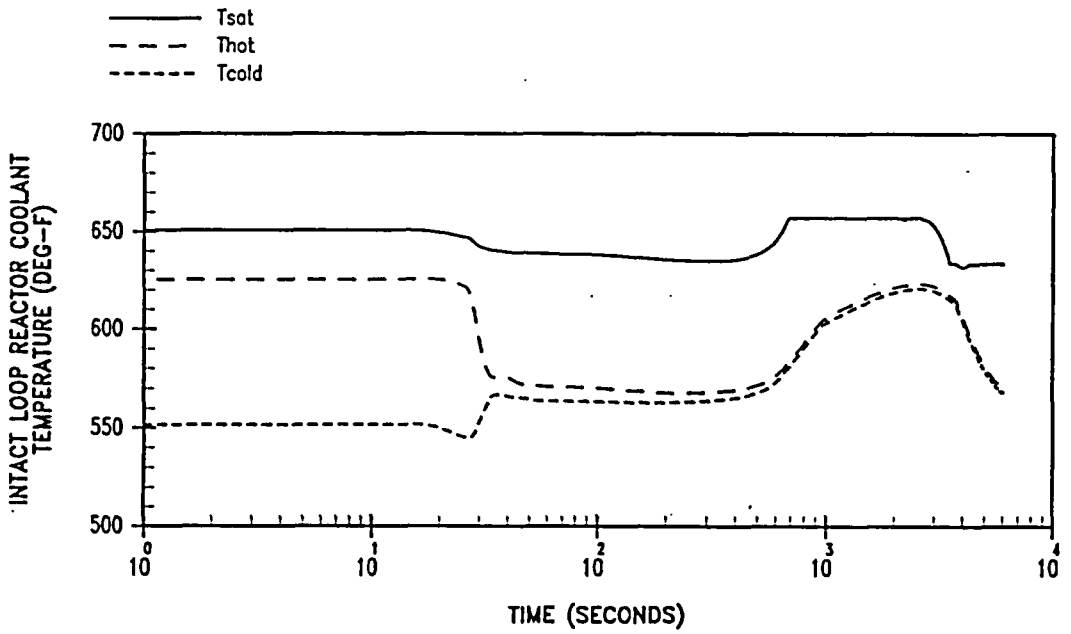
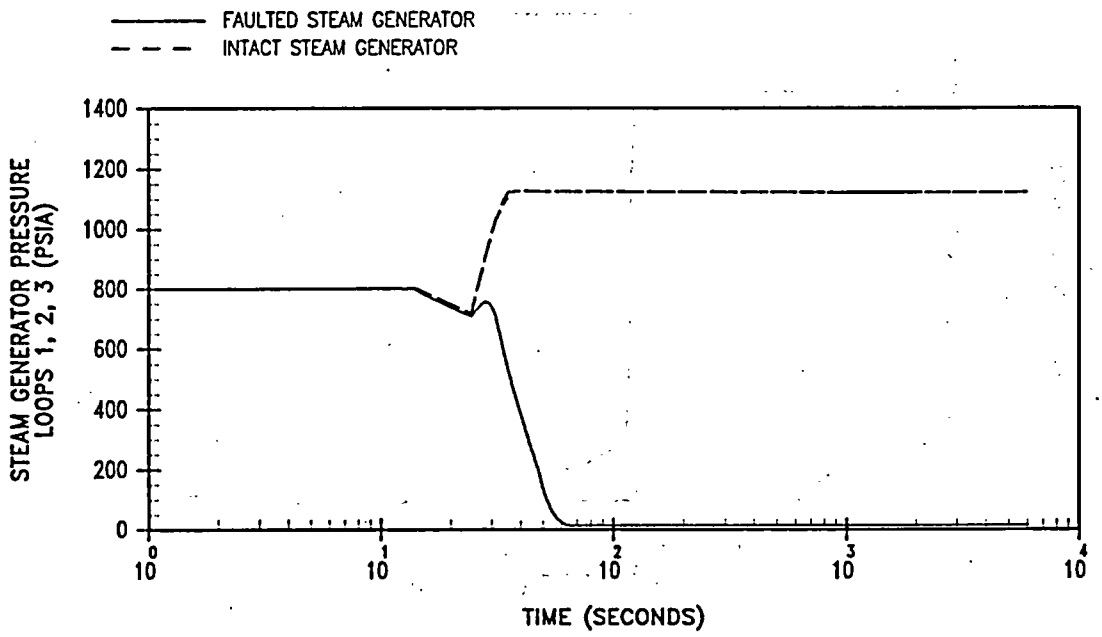


Figure 5.3.17-4A
BVPS-1 Feedline Rupture with Offsite Power Available
Reactor Coolant Temperature versus Time for the Faulted and Intact Loops



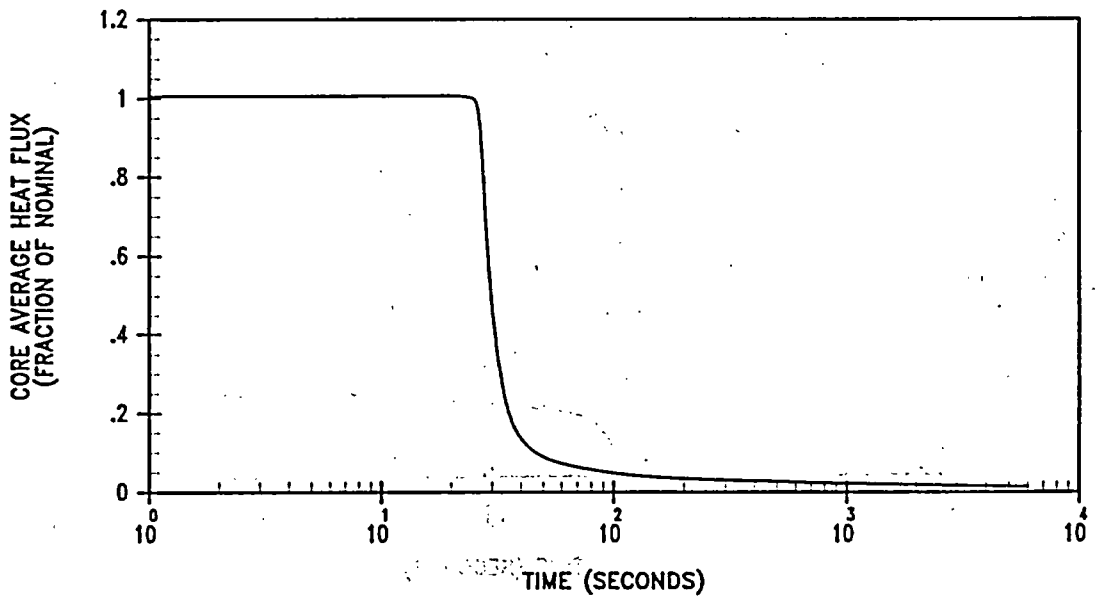
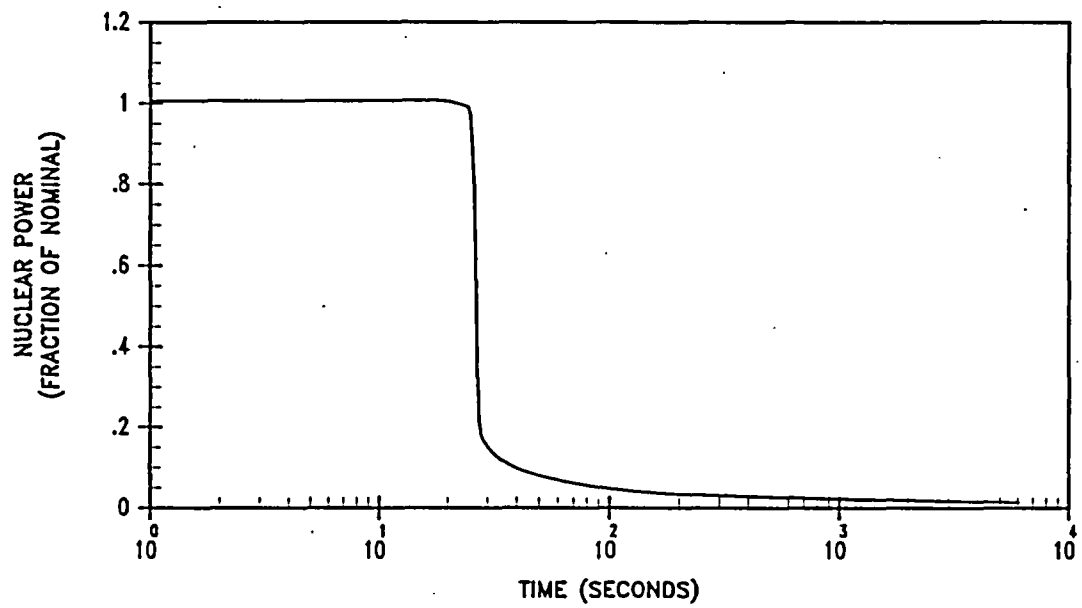


Figure 5.3.17-5A
BVPS-1 Feedline Rupture with Offsite Power Available
Steam Generator Pressure and Core Heat Flux versus Time



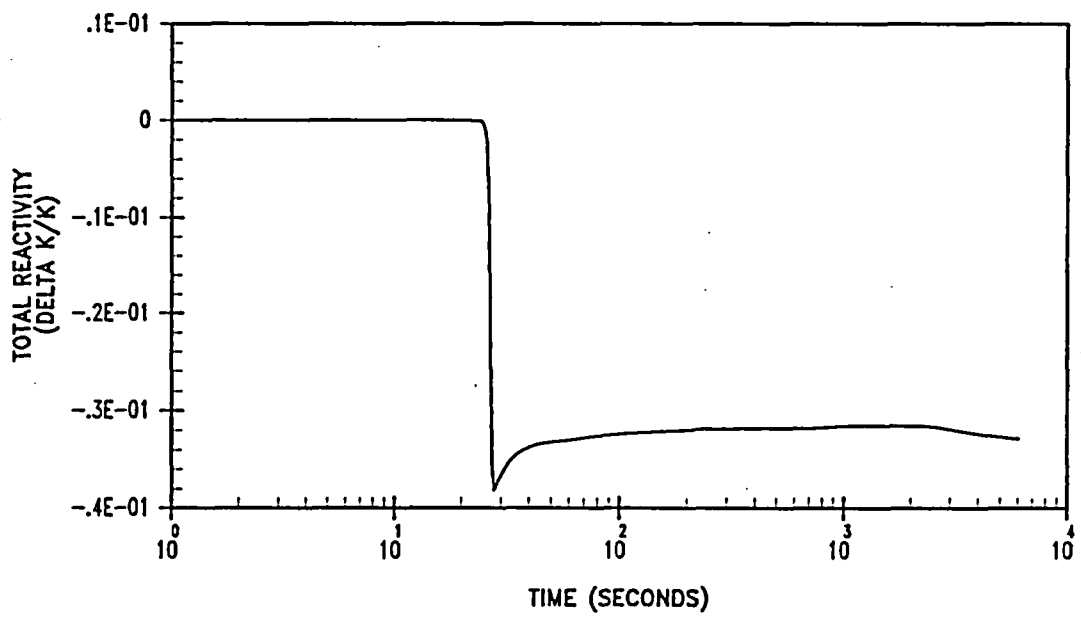
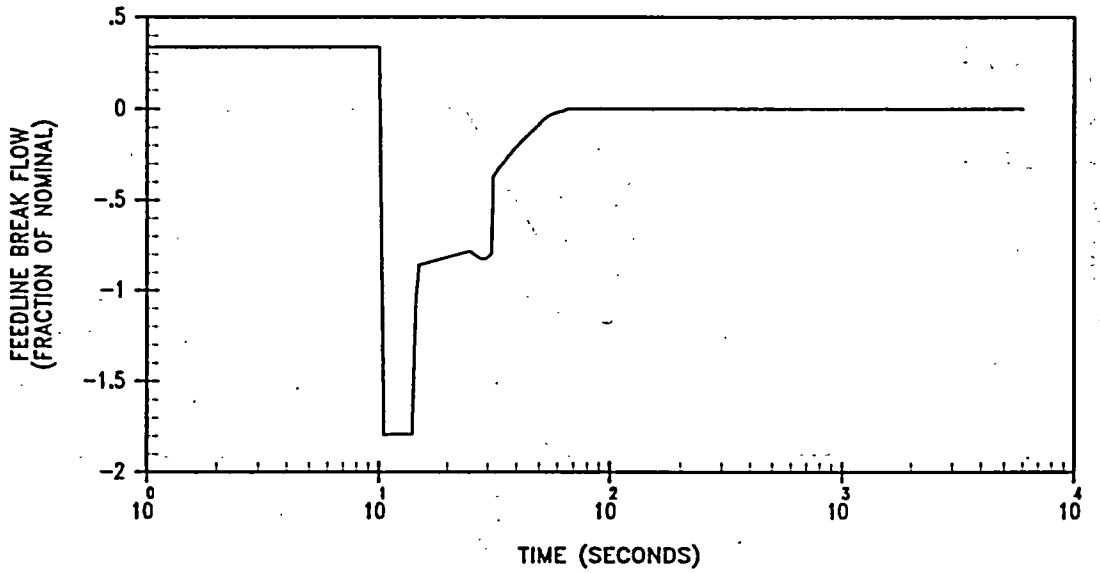


Figure 5.3.17-6A
BVPS-1 Feedline Rupture without Offsite Power Available
Nuclear Power and Total Reactivity versus Time



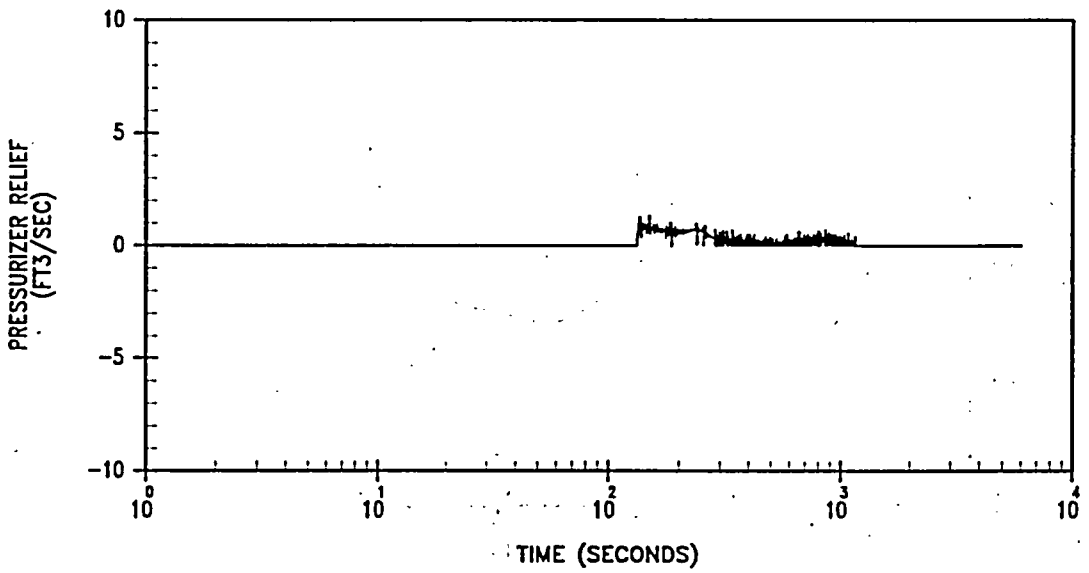
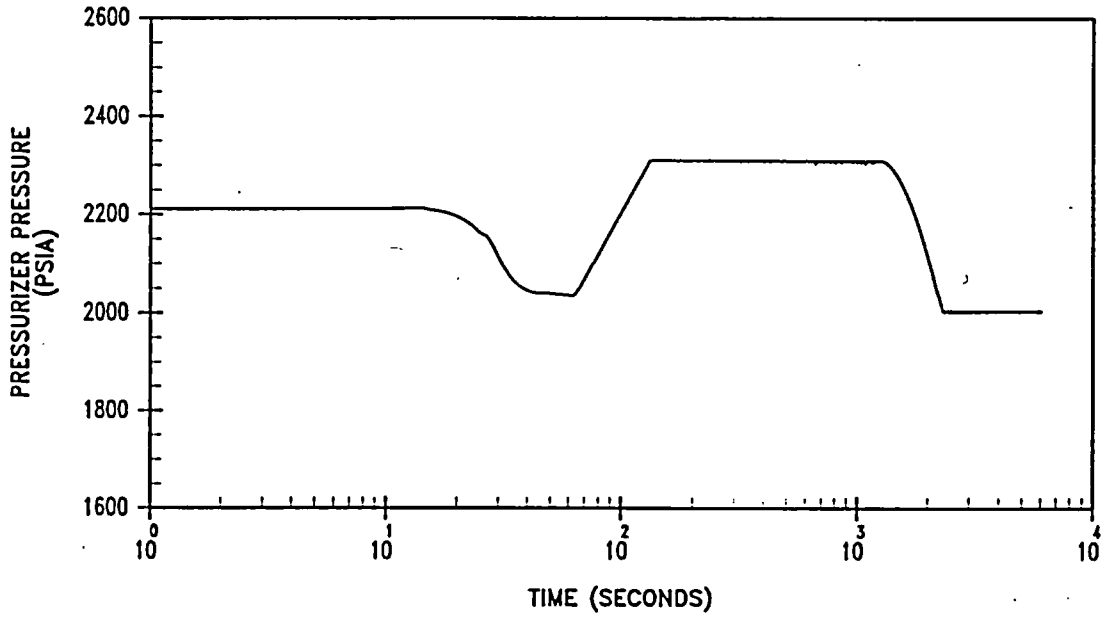


Figure 5.3.17-7A
BVPS-1 Feedline Rupture without Offsite Power Available
Feedline Break Flow and Pressurizer Relief versus Time



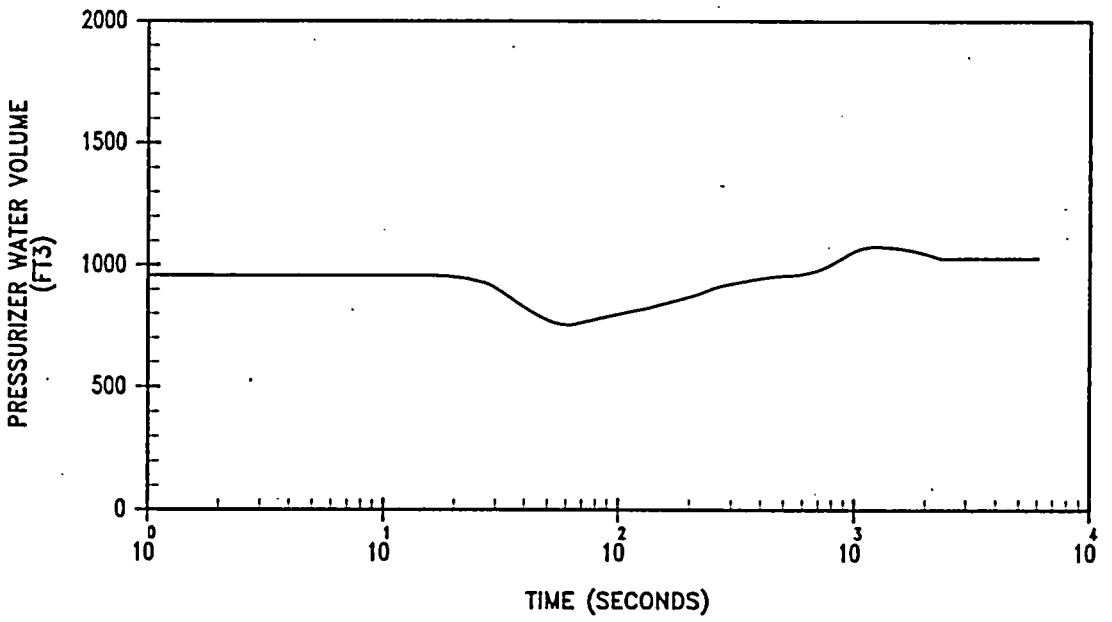
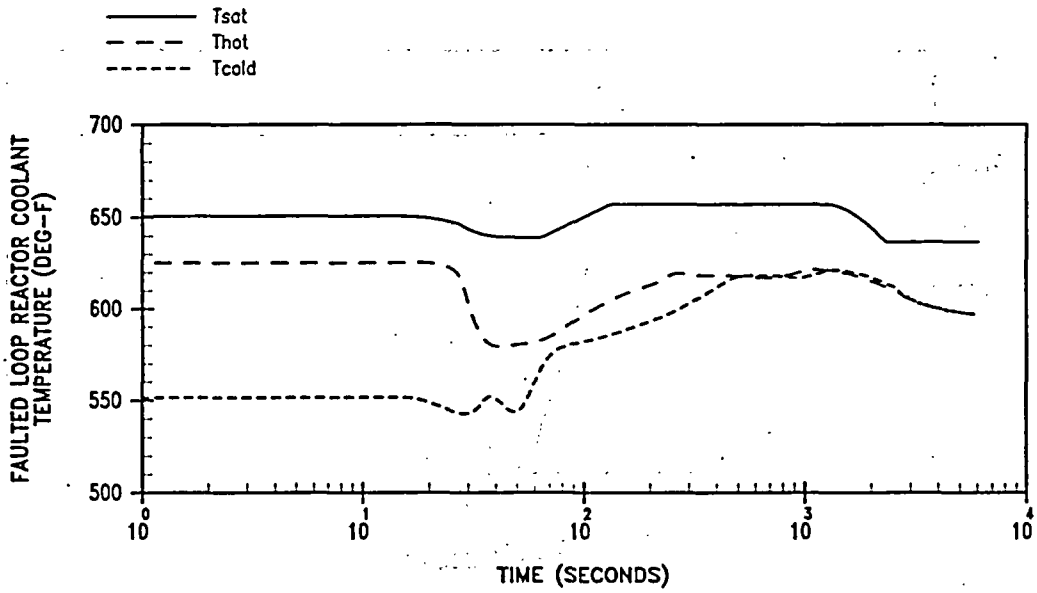


Figure 5.3.17-8A
BVPS-1 Feedline Rupture without Offsite Power Available
Pressurizer Pressure and Pressurizer Water Volume versus Time



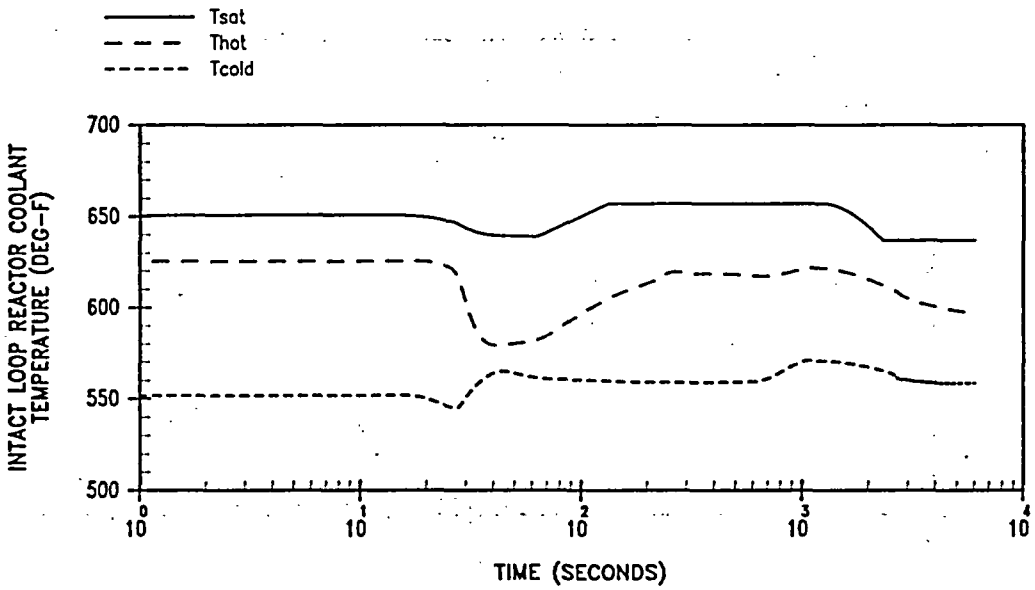
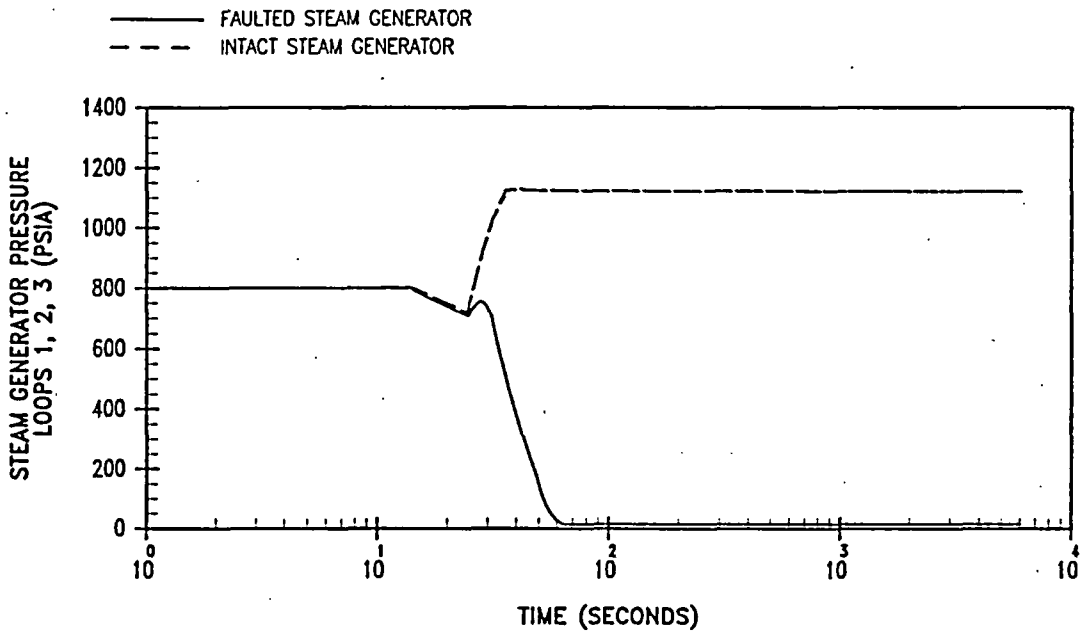


Figure 5.3.17-9A
BVPS-1 Feedline Rupture without Offsite Power Available
Reactor Coolant Temperature versus Time for the Faulted and Intact Loops



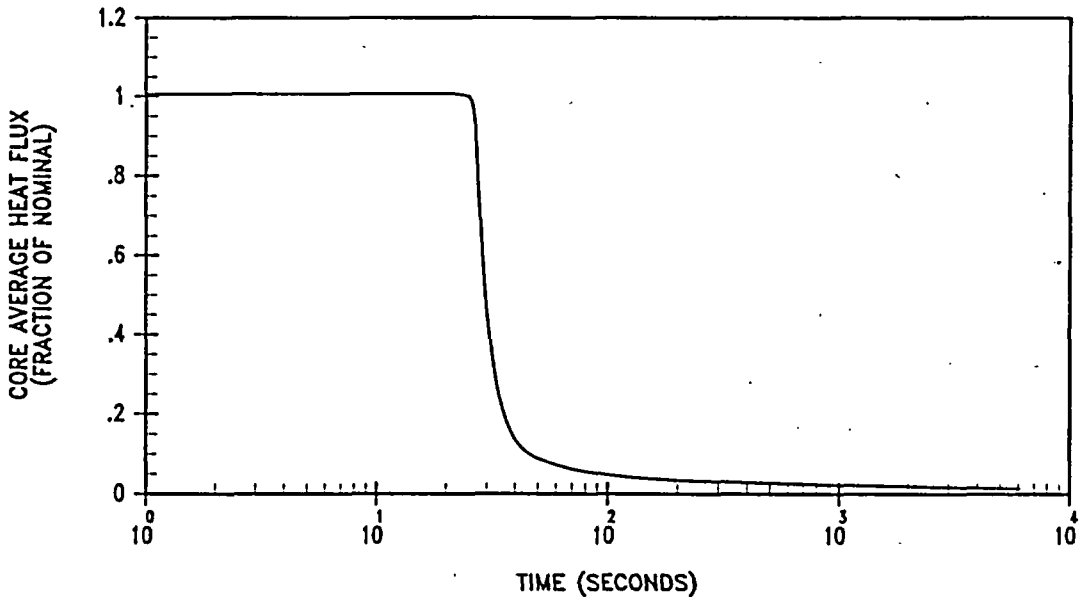


Figure 5.3.17-10A
BVPS-1 Feedline Rupture without Offsite Power Available
Steam Generator Pressure and Core Heat Flux versus Time

5.3.18 Spurious Operation of the Safety Injection System at Power (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.3.19 Steam System Piping Failure at Full Power

5.3.19.1 Identification of Causes and Accident Description

The steam system piping failure accident analysis described in Section 5.3.12 is performed assuming a hot zero power initial condition with the control rods inserted in the core with the exception of the most reactive rod. Such a condition could occur while the reactor is at hot shutdown at the minimum required shutdown margin or after the plant has been tripped automatically by the reactor protection system or manually by the operator. For an at-power steamline break, the analysis of Section 5.3.12 represents the limiting condition with respect to core protection for the time period following reactor trip. The purpose of this section is to describe the analysis of a steam system piping failure occurring from at-power initial conditions to demonstrate that core protection is maintained prior to and immediately following reactor trip.

5.3.19.2 Input Parameters and Assumptions

Limiting transient condition statepoints were generated using the Revised Thermal Design Procedure as described in Reference 3. For RTDP applications, uncertainties on RCS initial conditions (temperature, pressure, and power) are included in the development of the DNBR limit value. When RTDP is not applicable, uncertainties are included in the initial conditions or are conservatively applied to the limiting transient condition in the calculation of the minimum DNBR.

a. Initial conditions – The initial core power, RCS temperature, and RCS pressure are assumed to be at their nominal steady-state full power values when generating the transient statepoints. Uncertainties are explicitly included in the DNBR calculations.

b. RCS Flow – Minimum Measured RCS flow is assumed when generating the transient statepoints. The Thermal Design Flow (TDF) is assumed in the DNBR calculations. The initial loop flows are assumed to be symmetric.

c. RCS Average Temperature – The full power RCS average temperature range is from 566.2° to 580.0°F. Since the full power steamline rupture – core response event is a DNB event, assuming a maximum RCS average temperature of 580.0°F is limiting.

d. Feedwater Temperature – The Main Feedwater analytical temperature range is from 400° to 455°F. A nominal feedwater temperature of 400°F is more limiting with respect to DNB for this event. Thus, a feedwater temperature of 400°F is assumed.

e. SG Model – The Model 54F replacement steam generators (RSGs) are analyzed for BVPS-1.

f. Break size – A spectrum of break sizes (14 break sizes) with break sizes ranging from small breaks starting at 0.1 ft^2, increasing in increments of 0.1 ft^2 up to a break size of 1.4 ft^2 are considered. Once the limiting case, with respect to peak heat flux and minimum DNBR is determined, the limiting break is further defined by using an incremental break area of 0.01 ft^2.

g. Reactivity coefficients – The analysis assumed maximum moderator reactivity feedback and minimum Doppler power feedback to maximize the power increase following the break.

h. Protection system – The protection system features that mitigate the effects of a steamline break are described in Section 5.3.12. This analysis only considers the initial phase of the transient from at-power conditions. Protection in this phase of the transient is provided by reactor trip, if necessary. Section 5.3.12 presents the analysis of the bounding transient following reactor trip, where other protection system features are actuated to mitigate the effects of the steamline break.

i. Control systems – The only control that is assumed to function during a full power steamline rupture – core response event is the main feedwater system. For this event, the feedwater flow is set to match the steam flow.

5.3.19.3 Description of Analysis

The analysis of the steamline break at power for the EPU was performed as follows:

a. The LOFTRAN code (Reference 1) was used to calculate the nuclear power, core heat flux, and reactor coolant system temperature and pressure transients resulting from the cooldown following the steamline break.

b. The core radial and axial peaking factors were determined using the thermal-hydraulic conditions from LOFTRAN as input to the nuclear core models. A detailed thermal-hydraulic code, VIPRE (Reference 2), was used to calculate the DNBR for the limiting time during the transient. The DNBR calculations were performed using the W-3 correlation. Since the initial conditions uncertainties are not statistically included in the W-3 DNBR limit (of 1.30), uncertainties on power, temperature, pressure, etc. were applied to the limiting statepoints and the Thermal Design Flow was assumed in the calculation of the minimum DNBR.

5.3.19.4 Acceptance Criteria and Results

Depending on the size of the break, this event is classified as either a Condition III (infrequent fault) or Condition IV (limiting fault) event, however, the analysis is done to the more conservative Condition II acceptance criteria. The acceptance criteria for this event are consistent with those stated in Subsection 5.3.12.4

For BVPS-1, the limiting break size from the spectrum of break sizes analyzed is 0.6 ft^2. A DNB analysis was performed for the limiting point in the transient which determined that the DNB design basis is met. The sequence of events for the limiting case with a 0.6 ft^2 break is shown in Table 5.3.19-1. Plots for this limiting case are provided in Figures 5.3.19-1A through 5.3.19-4A.

5.3.19.5 Conclusions

For BVPS-1, the 0.6 ft^2 break size is the most limiting break size with respect to peak heat flux and minimum DNBR for the full power steamline rupture – core response event.

The DNB design basis is met. Therefore, this event does not adversely affect the core or RCS, and all applicable criteria are met.

The results and conclusions of the analysis performed for the steam system piping failure at full power for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt. Furthermore, the results and conclusions of this analysis will be confirmed on a cycle specific basis as part of the normal reload process.

5.3.19.6 References

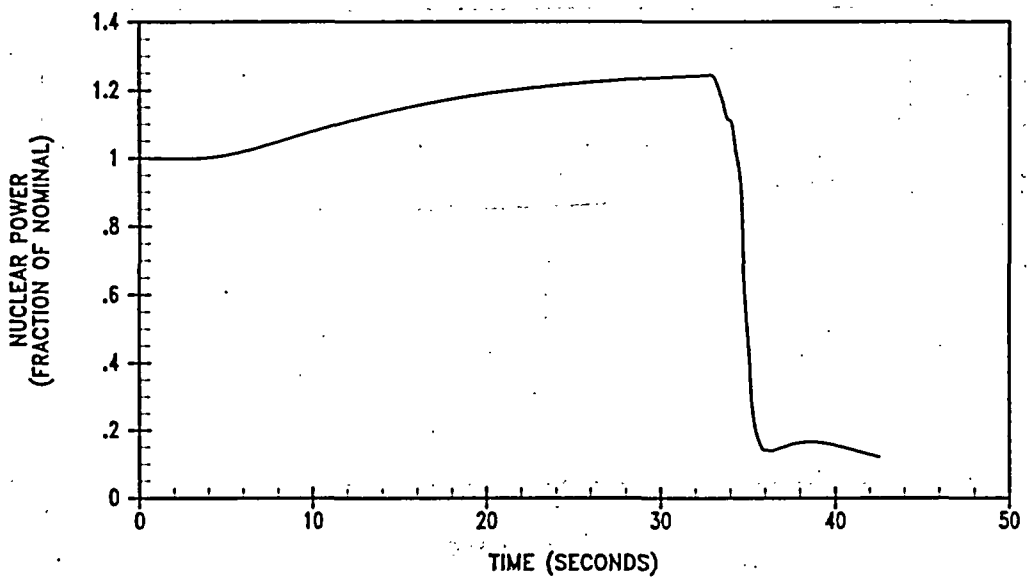
1. Burnett, T.W.T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.

2. Sung, Y. X. et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), October 1999.

3. Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non- Proprietary), April 1989.

Table 5.3.19-1
Time Sequence of Events – Steam System Piping Failure at Full Power (Core Response)

Event	BVPS-1 Time (sec)	BVPS-2 Time (sec)
Steam line ruptures	0.0	NA
Overpower ΔT reactor trip setpoint reached	30.4	NA
Rods begin to drop	32.4	NA
Minimum DNBR occurs	33.0	NA
Peak core heat flux occurs	33.0	NA



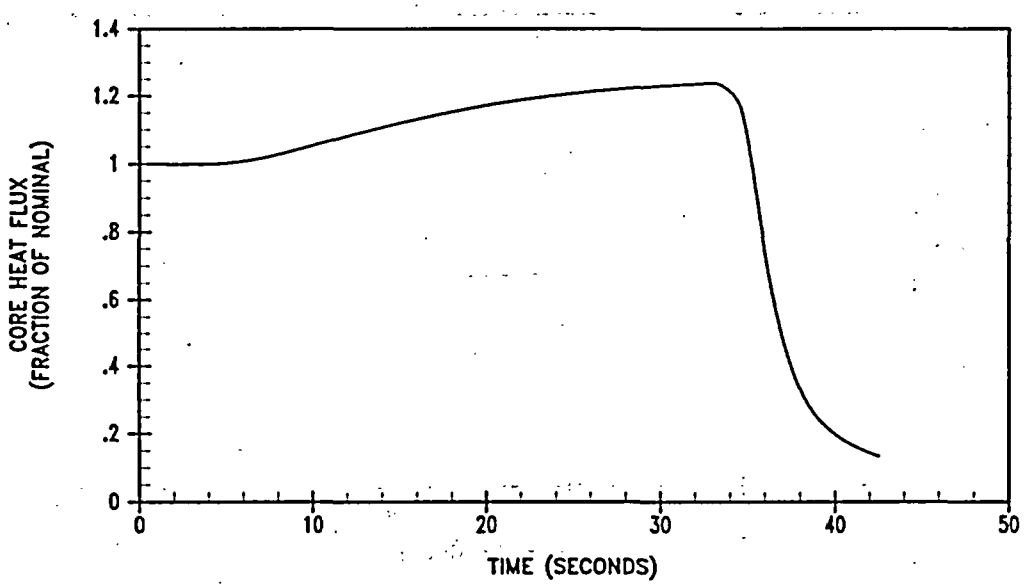
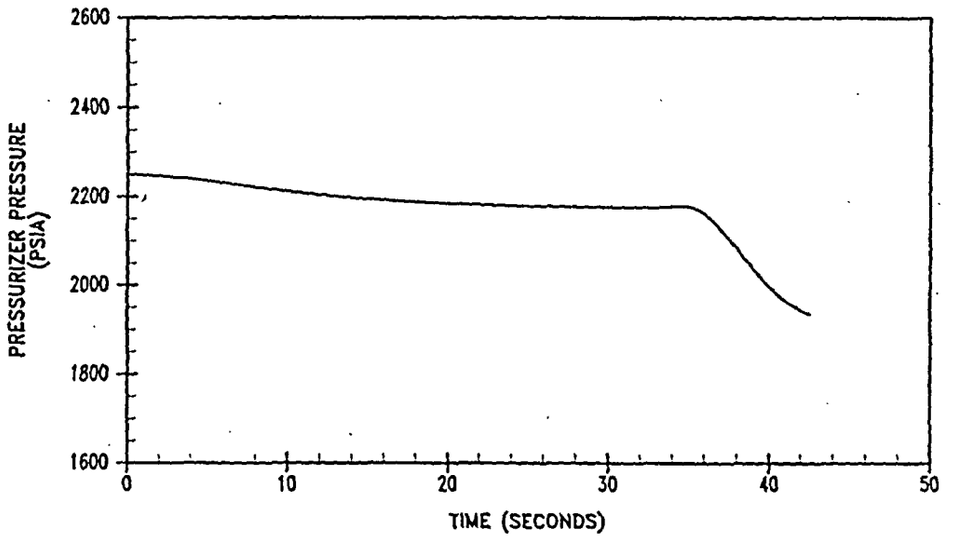


Figure 5.3.19-1A
BVPS-1 Steam System Piping Failure at Power – 0.6 ft^2 Break
Nuclear Power and Core Heat Flux versus Time



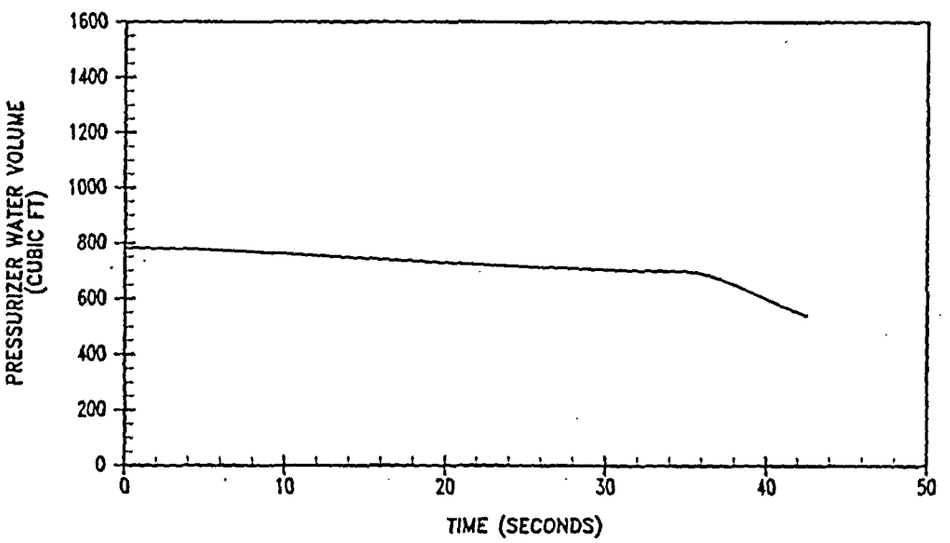
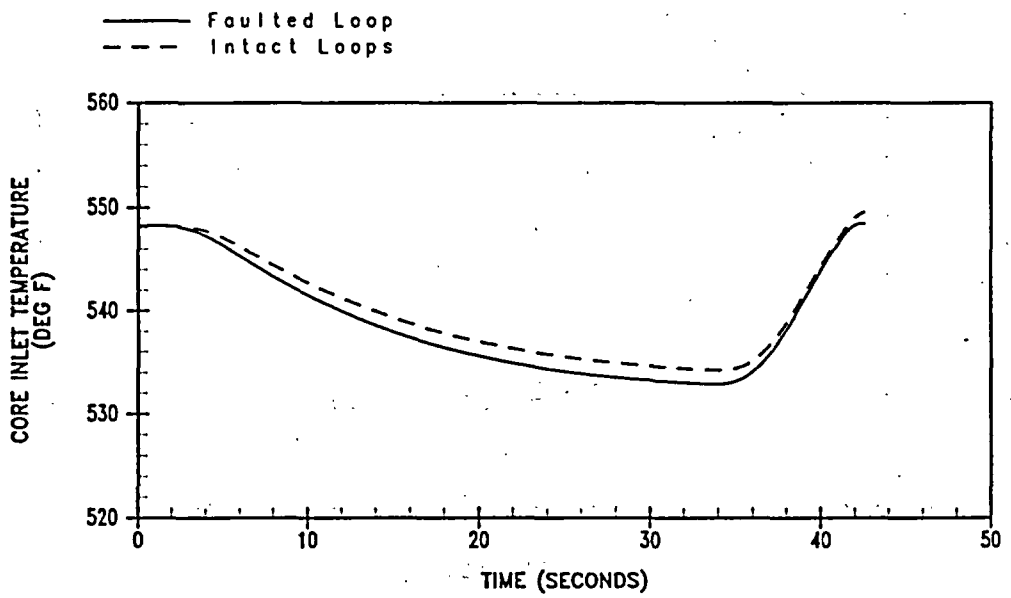


Figure 5.3.19-2A
BVPS-1 Steam System Piping Failure at Power – 0.6 ft^2 Break
Pressurizer Pressure and Pressurizer Water Volume versus Time



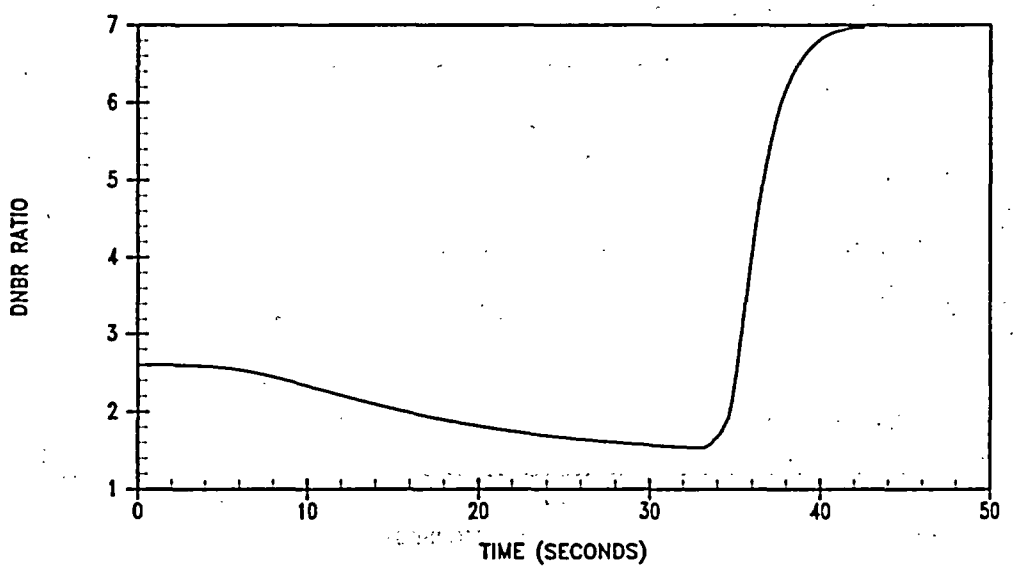
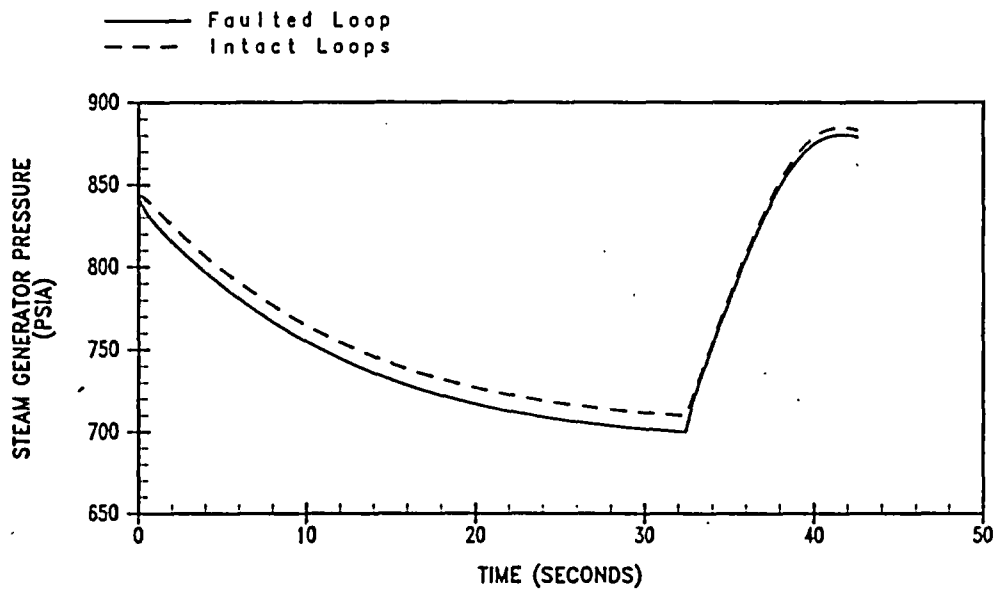


Figure 5.3.19-3A
BVPS-1 Steam System Piping Failure at Power – 0.6 ft^2 Break
Core Inlet Temperature and DNBR Ratio versus Time



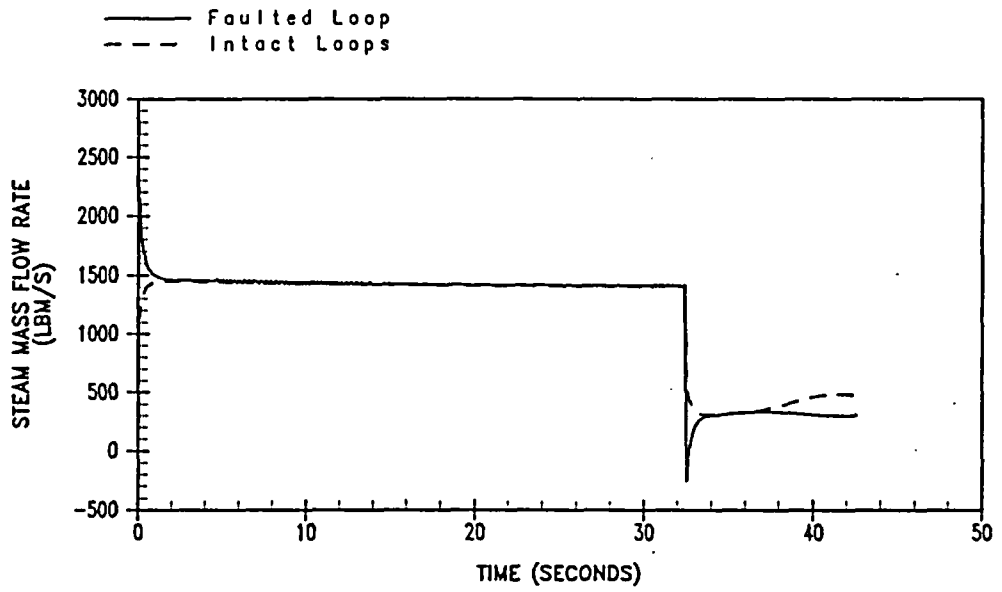


Figure 5.3.19-4A
BVPS-1 Steam System Piping Failure at Power – 0.6 ft^2 Break
Steam Generator Pressure and Steam Mass Flow Rate versus Time

5.3.20 Summary

The UFSAR non-LOCA analyses applicable to BVPS-1 were reanalyzed to support operation at EPU conditions. The preceding Sections 5.3.2 through 5.3.19 discuss the analyses in detail. In each case, it was demonstrated that the applicable acceptance criteria are met with a nominal NSSS power of 2910 MWt. For BVPS-1, the analyses were performed to support the replacement Model 54F steam generators. The protection system setpoints and the corresponding time responses are given in Tables 5.3.1-2A and 5.3.1-3A. Important initial conditions are given in Table 5.3.1-4A.

The following tables summarize the results of the analyses performed to support the EPU of BVPS-1 to the NSSS power of 2910 MWt.

The results of the UFSAR non-LOCA analyses performed for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

Table 5.3.20-1A
BVPS-1 Condition II DNB Event Results

Event Name	UFSAR Section	Report Section	Minimum DNBR	Peak Primary Pressure (psia)	Peak Secondary Pressure (psia)
RCCA Bank Withdrawal from Subcritical	14.1.1	5.3.2	Limit met(5,6)	N/A	N/A
RCCA Bank Withdrawal at Power	14.1.2	5.3.3	1.57	N/A(1)	1170.1
RCCA Misalignment	14.1.3	5.3.4	Limit met(5)	N/A	N/A
Loss of Load	14.1.7	5.3.6	2.23	2744.6(4)	1187.7
Feedwater System Malfunctions					
a. Feedwater Flow Increase	14.1.9	5.3.9	1.75(7)	2357.0	1124.0
b. Feedwater Enthalpy Decrease	14.1.9	5.3.9	1.67	2300.0	914.0
Excessive Load Increase(2)	14.1.10	5.3.10	Limit met	Limit met	Limit met
RCS Depressurization	14.1.15	5.3.11	1.62	N/A	N/A
Main Steam Pipe Rupture (HZP)(3)	14.2.5.1	5.3.12	Limit met(5,6)	N/A	N/A
Partial Loss of Flow	14.1.5	5.3.13	2.25(8)	2373.8	989.0
Complete Loss of Flow(3)	14.2.9	5.3.14	1.64(8)	2504.1	992.8
Limits	---	---	1.55	2748.5	1208.5

Notes:

(1) A generic Westinghouse evaluation addresses peak pressures for Rod Withdrawal at Power analyses.

(2) Current methodology for evaluating this event involves a comparison of conservative generic statepoints to the plant specific core thermal limits. In all cases, the generic statepoints are bounded by the core thermal limits.

(3) These events are not Condition II events but are analyzed to the more restrictive Condition II acceptance criteria.

(4) The analysis supports a pressurizer safety valve setpoint tolerance of +/-3.0%

(5) DNB statepoints are evaluated and the conclusion is that the limits are met.

(6) The 1.55 DNBR limit listed above is not applicable for these events. See Table 6.1-3 for the applicable DNB correlations and limits.

(7) The results reported are for the HFP case. An additional case was analyzed at HZP conditions. It was concluded that this case is bounded by the HZP steamline break analysis (UFSAR 14.2.5.1).

(8) These values are applicable for the RFA fuel. For the V5H fuel, the Partial Loss of Flow minimum DNBR is 1.90 compared to a limit of 1.32 (thimble cell) and the Complete Loss of Flow minimum DNBR is 1.39 compared to a limit of 1.33 (typical cell).

Table 5.3.20-2A
BVPS-1 Locked Rotor Analysis Results

Event Name	UFSAR Section	Report Section	Percentage of Rods-in-DNB (%)	Peak Primary Pressure (psia)
Locked Rotor	14.2.7	5.3.15	<20	2716 (1)
Limits	---	---	20	2997

Note:
(1) The peak Reactor Coolant System pressure reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits.

Table 5.3.20-3A
BVPS-1 Pressurizer Filling Event Results

Event Name	UFSAR Section	Report Section	Peak Pressurizer Volume (ft^3)
Loss of Normal Feedwater	14.1.8	5.3.7	1384.0
Loss of Non-Emergency AC Power	14.1.11	5.3.8	1224.0
Spurious Safety Injection at Power	14.1.16	5.3.18	NA
Limits	---	---	1458.1

Note:
NA

Table 5.3.20-4A BVPS-1 Feedline Break Analysis Results			
Case	UFSAR Section	Report Section	Margin to Hot Leg Boiling (°F)
With offsite power	14.2.5.2	5.3.17	14.35
Without offsite power	---	---	24.33
Limits	---	---	0.0

Table 5.3.20-5A
BVPS-1 Rod Ejection Analysis Results (EPU Table)

(This table number is included to maintain numbering consistency with the EPU Licensing Report. The information in this table is not applicable for the RSG Licensing Report.)

Table 5.3.20-6A BVPS-1 Uncontrolled Boron Dilution Analysis Results			
Case	UFSAR Section	Report Section	Time From Start of Transient to Loss of Shutdown Margin (minutes)
Mode 1 – Manual Rod Control	14.1.4	5.3.5	30.4
Mode 1 – Automatic Rod Control	---	---	31.7
Mode 2	---	---	33.3
Mode 3	---	---	15.3
Limits	---	---	15.0

5.4 STEAM GENERATOR TUBE RUPTURE

BVPS-1 includes analysis for a design basis steam generator tube rupture (SGTR) event to demonstrate that the potential radiological consequences are acceptable. The SGTR analysis methodology for BVPS-1 as presented in the Updated Final Safety Analysis Report (UFSAR) consists of a thermal-hydraulic analysis to provide tube rupture data (e.g., break flow and steam releases) as input to the BVPS-1 radiological consequences analysis.

Additionally, an operational response analysis of SGTR was performed for BVPS-1. This operational response analysis was performed to develop information for operator training. The analysis demonstrated margin to steam generator overfill and confirmed that the BVPS-1 licensing basis analysis methodology provides conservative tube rupture data (e.g., break flow and steam releases) as input to radiological consequences analysis.

The BVPS-1 licensing basis analysis for a SGTR event assumes that release from the ruptured steam generator is terminated in 30 minutes but the analysis methodology does not explicitly address the single failure criterion of 10 CFR 50, Appendix A. The EPU evaluations reflect the existing BVPS-1 licensing basis, i.e., no single failure is modeled. However, the need to address the single failure criterion was identified and entered into the BVPS Corrective Action Program. FENOC resolved this issue by conducting further operational response analysis, such that the single failure criterion is met for a BVPS-1 SGTR event. This operational response analysis demonstrates that the BVPS-1 licensing basis SGTR analysis methodology is conservative.

5.4.1 BVPS-1 Thermal and Hydraulic Analysis for Offsite Radiological Consequences

5.4.1.1 Introduction

In support of the EPU Project for BVPS-1, a steam generator tube rupture (SGTR) thermal-hydraulic analysis for use in the calculation of radiological consequences has been performed. The SGTR analysis supports a T_{avg} window range of 566.2° up to 580°F, secondary-side conditions (e.g., steam pressure, flow, temperature) based on high and low steam generator tube plugging (SGTP) (0% up to 22%). The SGTR analysis also supports the Model 54F replacement steam generators. In order to bound all possible conditions, four separate cases have been analyzed as follows:

1. T_{avg} = 566.2°F and SGTP = 0%
2. T_{avg} = 566.2°F and SGTP = 22%
3. T_{avg} = 580.0°F and SGTP = 0%
4. T_{avg} = 580.0°F and SGTP = 22%

The major hazard associated with an SGTR event is the radiological consequences resulting from the transfer of radioactive reactor coolant to the secondary side of the ruptured steam generator and subsequent release of radioactivity to the atmosphere. The primary thermal-hydraulic parameters which affect the calculation of offsite doses for an SGTR include the amount of reactor coolant transferred to the secondary side of the ruptured steam generator, the amount of primary-to-secondary break flow that flashes to steam and the amount of steam released from the ruptured steam generator to the atmosphere.

The accident analyzed is the double-ended rupture of a single steam generator tube. It is assumed that the primary-to-secondary break flow following an SGTR results in depressurization of the reactor coolant system (RCS), and that reactor trip and safety injection (SI) are automatically initiated on low pressurizer pressure. Loss of offsite power (LOOP) is assumed to occur at reactor trip resulting in the release of steam to the atmosphere via the steam generator atmospheric steam dump valves (ASDVs) and/or safety valves. Following SI actuation, it is assumed that the RCS pressure stabilizes at the value where the SI and break flow rates are equal. In the analysis, the equilibrium primary-to-secondary break flow is assumed to persist until 30 minutes after the initiation of the SGTR. Break flow and the steam releases from the ruptured steam generator are calculated for the initial 30 minute period.

After 30 minutes, it is assumed in the analysis that steam is released only from the intact steam generators in order to dissipate the core decay heat and to subsequently cool the plant down to the residual heat removal (RHR) system operating conditions. It is assumed that plant cooldown to RHR operating conditions is accomplished within 8 hours after initiation of the SGTR and that steam releases are terminated at that time. A primary-side and secondary-side mass and energy balance is used to calculate the steam release and feedwater flow for the intact steam generators from 0 to 2 hours and from 2 to 8 hours.

5.4.1.2 Input Parameters and Assumptions

The primary-side and secondary-side operating conditions for EPU are documented in Section 2.1.1. A summary of key input assumptions for the SGTR event follows.

High-Head Safety Injection (HHSI) Flow Rates

A larger SI flowrate results in a greater RCS equilibrium pressure and, consequently, higher break flow. Maximum HHSI flowrates were, therefore, assumed for this analysis.

RHR Cut-in Time

The RHR cut-in time based on the RCS heat load and RHR heat removal capacity is conservatively calculated and modeled in the SGTR analysis. This cut-in time affects the duration of long-term steam releases from the intact steam generators to the atmosphere following termination of the break flow. The effect of RHR cut-in time on long-term doses, however, is not significant since the radiation released from the intact steam generators is small relative to that released by the ruptured steam generator. An RHR cut-in time of 8 hours has been assumed.

Break Flow Flashing Fraction

A portion of the break flow will flash directly to steam upon entering the secondary side of the ruptured steam generator. Since a transient break flow calculation is not performed for BVPS-1, a detailed time-dependent flashing fraction that incorporates the expected changes in primary-side temperatures cannot be calculated. Instead, a conservative calculation of the flashing fraction is performed using the limiting conditions from the break flow calculation cases. Two time intervals are considered, as in the break flow calculations; pre-reactor trip and post-reactor trip (SI initiation occurs concurrently with

reactor trip). Since the RCS and steam generator conditions are different before and after the trip, different flashing fractions would be expected.

The flashing fraction is based on the difference between the primary-side fluid enthalpy and the saturation enthalpy on the secondary side. Therefore, the highest flashing will be predicted for the case with the highest primary-side temperatures. For the flashing fraction calculations, it is conservatively assumed that all of the break flow is at the hot leg temperature (the break is assumed to be on the hot leg side of the steam generator). Similarly, a lower secondary-side pressure maximizes the difference in the primary and secondary enthalpies, resulting in more flashing. The highest pre-trip flashing fraction based on the range of operating conditions covered by this analysis is for the case with a hot leg temperature of 603.9°F, an initial RCS pressure of 2250 psia, and an initial secondary pressure of 623 psia. The case with a hot leg temperature of 617°F would have a lower flashing fraction because the corresponding conservatively high secondary pressure is 831 psia and the flashing is more dependent on secondary pressure than hot leg temperature. All cases consider the same post-trip RCS pressure of 1888.4 psia and post-trip steam generator pressure of 932.75 psia. The highest post-trip flashing fraction, based on the range of operating temperatures covered by this analysis, is for a case with a hot leg temperature of 617°F. It is conservatively assumed that the hot leg temperature is not reduced for the 30 minutes in which break flow is calculated.

Miscellaneous Parameter Assumptions

- Low pressurizer pressure SI actuation setpoint = 1860 psia
- Lowest steam generator safety valve reseat pressure = 932.75 psia, and includes 11.6% main steam safety valve (MSSV) blowdown and 3% safety valve setpoint tolerance.

5.4.1.3 Description of Analyses Performed

A T_{avg} window of 566.2° up to 580.0°F is considered. Section 2.1.1 documents four Performance Capability Working Group (PCWG) cases that have been used for the BVPS-1 SGTR analysis.

Cases are analyzed at a T_{avg} of 566.2° and 580.0°F, with 0% and 22% SGTP. All the cases support a power of 2910 MWt (NSSS power) and thermal design flow (TDF) of 87200 gpm/loop.

Break Flow, Steam Releases, and Feedwater Flows

In total, four cases were considered in the SGTR thermal-hydraulic analysis to bound the EPU operating conditions. Note that these four cases are individually analyzed in order to determine the limiting steam release and limiting break flow between 0 and 30 minutes for the radiological consequences calculation. A single calculation is performed to determine long-term steam releases from, and feedwater flow to, the intact steam generators for the time interval from the start of the event (0 hours) to 2 hours and from 2 hours to RHR cut-in at 8 hours. The 0 to 2 hour calculations use the 0 to 30 minute intact steam generator steam release and feedwater flow results from the case that resulted in the highest intact steam generator steam and feedwater flow rates.

A mass and energy balance is assumed in the calculation of the break flow and steam releases. The energy balance is based on the following assumed conditions at 30 minutes: (1) the RCS fluid is at the equilibrium pressure and no-load temperature, (2) the pressurizer fluid and steam generator secondary fluid for both the ruptured and intact steam generators is saturated at no-load temperature, and (3) the core and clad, primary system metal, pressurizer metal, and steam generator secondary metal are at no-load temperature. Since the RCS fluid is not at a consistent energy state with the ruptured steam generator and the remainder of the primary and secondary systems, energy must be dissipated to reduce the RCS fluid from equilibrium pressure and no-load temperature to saturation at no-load temperature. It is assumed that the plant is then maintained stable at no-load temperature until 2 hours, and that steam will be released from only the intact steam generators to dissipate the energy from the reduction in the RCS fluid energy state and the core decay heat from 30 minutes to 2 hours.

After 2 hours, it is assumed that plant cooldown to RHR cut-in conditions is initiated by releasing steam from only the intact steam generators. It is assumed that cooldown to RHR cut-in conditions is completed within 8 hours after the SGTR. After the RHR cut-in conditions are reached, it is assumed that further cooldown is performed using the RHR system and that the steam release from the intact steam generators is terminated.

The energy to be dissipated from 2 to 8 hours is calculated from an energy balance for the primary and secondary systems between no-load conditions at 2 hours and the RHR entry conditions at 8 hours, plus the core decay heat load from 2 to 8 hours. The amount of steam released from the intact steam generators is calculated from a mass and energy balance for the intact steam generators.

5.4.1.4 Results and Acceptance Criteria

The analysis is performed to calculate the mass transfer data for input to the radiological consequences analysis. As such no acceptance criteria are defined. The results of the analysis are used as input to the radiological consequences analysis.

The tube rupture break flow and ruptured steam generator atmospheric steam releases (post-trip) from 0 to 30 minutes for the different SGTR cases are summarized in Table 5.4.1-1. Based on the results of these SGTR cases, bounding values for break flow and steam releases are provided in Table 5.4.1-2 along with flashing fractions, long-term steam releases, and feedwater flows for use in radiological consequences analysis. The maximum break flow and steam releases represent bounding values which are conservative for an offsite dose evaluation. The values in Table 5.4.1-3 include an approximate 10% increase in mass transfer rates for use in a conservative radiological analysis. Increasing the mass transfer data prior to performing the radiological consequences analysis allows future plant changes that result in small increases in the mass transfer rates to be evaluated, without requiring the radiological analysis to be redone.

5.4.1.5 Conclusions

The BVPS-1 SGTR thermal-hydraulic analysis for use in the radiological consequences calculation has been completed in support of the EPU Project. Based on a primary-side and secondary-side mass and energy balance, the break flow and atmospheric steam releases from the ruptured and intact steam generators were calculated for 30 minutes. After 30 minutes, it was assumed that steam is released only

from the intact steam generators in order to dissipate the core decay heat and to subsequently cool the plant down to the RHR system operating conditions. For BVPS-1, it was assumed that plant cooldown to RHR operating conditions can be accomplished within 8 hours after initiation of the SGTR event and that steam releases are terminated at this time. A primary-side and secondary-side mass and energy balance was used to calculate the steam release and feedwater flow for the intact steam generators from 0 to 2 hours and from 2 to 8 hours.

The results and conclusions of the SGTR thermal-hydraulic analysis for offsite radiological consequences performed for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

Table 5.4.1-1 BVPS-1 Limiting SGTR Thermal-Hydraulic Results*	
Tube Rupture Break Flow for 0 to 30 Minutes	
T_{avg} = 566.2°F, 0% SGTP	135,900 lbm
T_{avg} = 566.2°F, 22% SGTP	136,300 lbm
T_{avg} = 580.0°F, 0% SGTP	134,700 lbm
T_{avg} = 580.0°F, 22% SGTP	135,500 lbm
Steam Release from Ruptured SG (Post-Trip) for 0 to 30 Minutes	
T_{avg} = 566.2°F, 0% SGTP	55,800 lbm
T_{avg} = 566.2°F, 22% SGTP	53,100 lbm
T_{avg} = 580.0°F, 0% SGTP	62,600 lbm
T_{avg} = 580.0°F, 22% SGTP	58,600 lbm
* Values rounded up to the nearest 100	

Table 5.4.1-2 BVPS-1 SGTR Thermal-Hydraulic Results for Radiological Dose Analysis	
Reactor Trip, SI Actuation, and Loss Of Offsite Power	224.72 seconds
Pre-Trip (less than 224.72 seconds)	
Tube Rupture Break Flow*	19,900 lbm
Percentage of Break Flow Which Flashes	22.27 %
Steam Release Rate to Condenser	1207.4 lbm/sec for each SG
Post-Trip (after 224.72 seconds)	
Tube Rupture Break Flow for post-trip to 30 minutes*	116,400 lbm
Percentage of Break Flow Which Flashes	16.45 %
Steam Release from Ruptured SG for post-trip to 30 minutes*	62,600 lbm
Steam Release from Intact SGs for post-trip to 2 hours*	379,200 lbm
Feedwater flow to Intact SGs for post-trip to 2 hours*	364,200 lbm
Steam Release from Intact SGs for 2 to 8 hours*	890,500 lbm
Feedwater flow to Intact SGs for 2 to 8 hours*	966,300 lbm
* Values rounded up to the nearest 100	

Table 5.4.1-3 BVPS-1 SGTR Thermal-Hydraulic Results for Radiological Dose Analysis With Additional 10%	
Reactor Trip, SI Actuation, and Loss Of Offsite Power	224.72 seconds
Pre-Trip (less than 224.72 seconds)	
Tube Rupture Break Flow*	21,900 lbm
Percentage of Break Flow Which Flashes	22.27 %
Steam Release Rate to Condenser	1207.4 lbm/sec for each SG
Post-Trip (after 224.72 seconds)	
Tube Rupture Break Flow for post-trip to 30 minutes*	128,000 lbm
Percentage of Break Flow Which Flashes	16.45 %
Steam Release from Ruptured SG for post-trip to 30 minutes*	68,900 lbm
Steam Release from Intact SGs for post-trip to 2 hours*	417,100 lbm
Feedwater flow to Intact SGs for post-trip to 2 hours*	400,600 lbm
Steam Release from Intact SGs for 2 to 8 hours*	979,500 lbm
Feedwater flow to Intact SGs for 2 to 8 hours*	1,062,900 lbm
* Values rounded up to the nearest 100	

5.4.2 BVPS-2 Margin to Steam Generator Overfill Analysis (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.4.3 BVPS-2 Thermal and Hydraulic Analysis for Offsite Radiological Consequences (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.5 LOCA MASS AND ENERGY RELEASES

The EPU Project included safety (accident) analyses for the Updated Final Safety Analysis Report (UFSAR) Loss of Coolant Accident (LOCA) mass and energy releases. The following LOCA mass and energy releases-related analyses were performed at EPU conditions:

- Long-Term LOCA Mass and Energy Releases
- Short-Term LOCA Mass and Energy Releases

The results of these analyses and evaluations were used as input to the containment analysis at EPU conditions. These mass and energy releases-related analyses were completed in support of the containment analysis and were previously submitted to the NRC for review and approval as part of the Beaver Valley Power Station Containment Conversion License Amendment Request (LAR) No. 317 (BVPS-1).

The results and conclusions of the analyses and evaluations performed for LOCA mass and energy releases for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

5.6 MSLB MASS AND ENERGY RELEASES

The EPU Project included safety (accident) analyses for the Updated Final Safety Analysis Report (UFSAR) Main Steam Line Break (MSLB) mass and energy releases. The following MSLB mass and energy releases-related analyses were performed at EPU conditions:

- MSLB Mass and Energy Releases Inside Containment
- MSLB Mass and Energy Releases Outside Containment
- Steam Releases for Radiological Dose Analysis

5.6.1 MSLB Mass and Energy Releases Inside Containment

The results of the long-term MSLB mass and energy releases inside containment were used as input to the containment analysis at EPU conditions. This analysis was completed in support of the containment analysis and was previously submitted to the NRC for review and approval as part of the Beaver Valley Power Station Containment Conversion License Amendment Request (LAR) No. 317 (BVPS-1).

The results and conclusions of the analyses performed for MSLB mass and energy releases inside containment for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

5.6.2 MSLB Mass and Energy Releases Outside Containment

5.6.2.1 Introduction

Steamline ruptures occurring outside the reactor containment structure may result in significant releases of high-energy fluid to the structures surrounding the steam systems. Superheated steam blowdowns following the steamline break have the potential to raise compartment temperatures outside containment. Early uncovery of the steam generator tube bundle maximizes the enthalpy of the superheated steam releases out the break. The impact of the steam releases depends on the plant configuration at the time of the break, the plant response to the break, as well as the size and location of the break. Because of the interrelationship among many of the factors that influence steamline break mass and energy releases, an appropriate determination of a single limiting case with respect to mass and energy releases cannot be made. Therefore, it is necessary to analyze the steamline break event outside containment for a range of conditions.

5.6.2.2 Input Parameters and Assumptions

The analysis inputs, assumptions, and methods pertaining to the main steamline break (MSLB) mass and energy (M&E) releases outside containment are presented in this section.

To determine the effects of plant power level and break area on the mass and energy releases from a ruptured steamline, spectra of both variables have been evaluated as part of the methodology development program documented in Reference 4. BVPS-1 has been included as part of the Category-4 plants in the analysis presented in Reference 4. At plant power levels of 102 and 70%, various break sizes have been defined ranging from 0.1 ft^2 to the equivalent of a full single-ended rupture of a main steamline. The assumed break locations presented in Reference 4 are both upstream and downstream of the main steamline check valve for BVPS-1.

The scope of the steamline break analysis presented in this report includes differing assumptions related to the effect of steam generator tube uncovery in the faulted-loop steam generator. Consistent with the current licensing-basis analysis, assumptions are made that minimize the time to achieve steam generator tube uncovery, which maximizes the superheated release duration. The emphasis on maximizing the value of the superheated steam enthalpy due to early steam generator tube uncovery is consistent with the methodology development program documented in Reference 4. Also addressed in this report are altered assumptions to increase the time to superheat steam conditions, i.e., increase the "soak time" duration. Maximizing the value of the steam enthalpy and the analysis assumptions that create the high enthalpy tend to lower the break flowrate, which may have the net result of lowering the energy release rate. Thus, maximizing steam enthalpy does not necessarily maximize the total energy release out the break. The analysis performed for the EPU Project includes assumptions related to maximizing the superheated steam releases as well as maximizing the "soak time" prior to superheated steam releases.

Based on the current licensing-basis analysis for BVPS-1, a limited break spectrum at both power levels (100.6 and 70%) has been analyzed at the EPU conditions associated with the Model 54F replacement steam generators (RSGs) for BVPS-1. Other assumptions regarding important plant conditions and features are discussed in the following paragraphs.

5.6.2.2.1 Initial Power Level

The initial power that is assumed for steamline break analyses outside containment affects the mass and energy releases and steam generator tube bundle uncovery in two ways. First, the steam generator water mass inventory increases with decreasing power levels; this will tend to delay uncovery of the steam generator tube bundle, although the increased steam pressure associated with lower power levels will cause a faster blowdown at the beginning of the transient. Second, the amount of stored energy and decay heat, as well as feedwater temperature, are less for lower power levels; this will result in lower primary temperatures and less primary-to-secondary heat transfer during the steamline break event.

Overall, steamline breaks initiated from lower power levels result in lower levels of steam superheating than breaks analyzed at full-power conditions. For this reason, steamline break outside containment mass and energy release calculations are limited to breaks initiated from a full-power or a representative near full-power condition, as presented in Reference 4; specifically:

- Full power – maximum allowable NSSS power plus uncertainty, i.e., 100.6% of rated power; and
- Near full power – 70% of maximum allowable NSSS power.

For this EPU analysis, the power levels and steamline break sizes are noted in Section 5.6.2.3 of this report.

In general, the plant initial conditions are assumed to be at the nominal value corresponding to the initial power for that case, with appropriate uncertainties included. Tables 5.6.2-1 and 5.6.2-2 identify the values assumed for RCS pressure, RCS vessel average temperature, RCS flow, pressurizer water volume, steam generator water level, steam generator pressure, and feedwater enthalpy corresponding to each power level analyzed. Steamline break mass releases and superheated steam enthalpies assuming an RCS average temperature at the high end of the T_{avg} window are conservative with respect to similar releases at the low end of the T_{avg} window. At the high end, there is a larger value for the superheated steam enthalpy available for release outside containment. The thermal design flowrate has been used for the RCS flow input consistent with the assumptions documented in Reference 1. The thermal design flowrate is also consistent with other MSLB analysis assumptions related to nonstatistical treatment of uncertainties, as well as RCS thermal-hydraulic inputs related to pressure drops and rod drop time.

Uncertainties on the initial conditions assumed in the analysis for the EPU Project have been applied only to the RCS average temperature (8.5°F), the steam generator mass (10% narrow-range span for BVPS-1) and the power fraction (0.6%) at full power. Nominal values are adequate for the initial conditions associated with pressurizer pressure and pressurizer water level. Uncertainty conditions are only applied to those parameters that could increase the enthalpy of superheated steam discharged out of the break.

5.6.2.2.2 Single-Failure Assumption

The single-failure assumption is dependent on whether the analysis is designed to maximize the superheated release duration or intended to increase the "soak time" duration prior to superheated steam release as discussed in Section 5.6.2.2. The limiting single failure for the scenario in which the superheated steam release is maximized is the failure of the largest capacity auxiliary feedwater (AFW) pump, the turbine-driven pump, resulting in minimum AFW flow. Variations in AFW flow can affect steamline break mass and energy releases in a number of ways including break mass flowrate, RCS temperature, tube bundle uncovery time and steam superheating. The failure in the AFW system results in a minimum AFW flow to the steam generators; the minimum AFW flow used in the analysis is conservatively based on two motor-driven AFW pumps.

However, for the scenario in which the total energy released over the duration of the event is maximized, the AFW system will not actuate for the steamline break areas included in the analysis. Thus, the single failure cannot be the typical one assumed for this event. The selection of the limiting single failure is difficult since operator action is assumed for actuation of the protection functions for all break sizes for BVPS-1. For the BVPS-1 steamline break cases that rely on operator action, there is no limiting single failure identified.

5.6.2.2.3 Main Feedwater System

The rapid depressurization that typically occurs following a steamline rupture results in large amounts of water being added to the steam generators through the main feedwater system. The main feedwater flow assumptions are dependent on whether the analysis is designed to maximize the superheated release duration or intended to increase the "soak time" duration prior to superheated steam release as discussed in Section 5.6.2.2. To maximize the superheated steam releases, main feedwater flow is conservatively modeled by assuming no increase in feedwater flow in response to the increases in steam flow following the steamline break event. This minimizes the total mass addition and associated cooling effects in the steam generators and causes the earliest onset of superheated steam released out of the break.

To increase the soak time until steam generator tube uncovery in the faulted-loop steam generator, the feedwater control system is modeled to allow for the increase in the main feedwater flow to match the increase in the steam flow. The steam flow is dependent on the power level and the break size, which determine the increase in the main feedwater flow.

Isolation of the main feedwater flow is assumed to be initiated following either a safety injection signal or a low RCS T_{avg} signal following (coincident with) a reactor trip. If neither a safety injection signal nor a low RCS T_{avg} signal is received, a manual isolation of the main feedwater system is assumed at 1800 seconds. The feedwater isolation response time is assumed to be 2 seconds accounting only for the delay associated with signal processing. Closing of the feedwater valves in the main feedwater lines is conservatively assumed to be instantaneous with respect to valve stroke time.

Steamline break mass and energy releases assuming a main feedwater temperature at the high end of the feedwater temperature window are conservative with respect to similar releases at the low end of the feedwater temperature window. At the high end, there is more energy available for release outside containment.

5.6.2.2.4 Auxiliary Feedwater System

Generally, within the first few minutes following a steamline break the AFW system is initiated on any one of several protection system signals. Addition of auxiliary feedwater to the steam generators will increase the secondary mass available to cover the tube bundle and reduces the amount of superheated steam produced. For this reason, AFW flow is minimized while actuation delays are maximized to accentuate the depletion of the initial secondary-side inventory. The volume of the AFW piping is maximized. A purging of the AFW piping is assumed, since maximum volume delays the injection of colder AFW into the steam generator, following any hotter feedwater resident in the piping up to the isolation valve closest to the steam generator. The less dense resident auxiliary feedwater exhibits a decreased mass addition to the faulted-loop steam generator than if the AFW is introduced directly into the steam generator. The large volume also delays the introduction of colder AFW into any steam generator, which reduces the amount of the cooldown effect on the primary side of the RCS. Auxiliary feedwater system assumptions that have been used in the analysis are presented in Table 5.6.2-3.

However, for the steamline break cases in which main feedwater flow increases to match the increase in the steam flow, a signal to actuate AFW flow is not received since main feedwater flow maintains the inventory in the steam generators.

5.6.2.2.5 Steam Generator Fluid Mass

A minimum initial steam generator mass in all the steam generators has been used in the steamline break cases designed to maximize the superheated release duration. The use of a reduced initial steam generator mass minimizes the availability of the heat sink afforded by the steam generators and leads to earlier tube bundle uncovery. The initial mass has been calculated as the value corresponding to the programmed level minus 10% narrow-range span for BVPS-1. All steam generator fluid masses are calculated assuming 0% tube plugging. This assumption is conservative with respect to the RCS cooldown through the steam generators resulting from the steamline break.

A nominal initial steam generator mass in the steam generators has been used in the steamline break cases intended to increase the "soak time" duration prior to superheated steam release. The use of a larger initial steam generator mass increases both the inventory availability for release out the break and the energy release into the compartment.

5.6.2.2.6 Steam Generator Reverse Heat Transfer

Once the steamline isolation is complete, the steam generators in the intact loops become sources of energy that can be transferred to the steam generator with the broken steamline. This energy transfer occurs via the primary coolant. As the primary plant cools, the temperature of the coolant flowing in the steam generator tubes could drop below the temperature of the secondary fluid in the intact steam generators, resulting in energy being returned to the primary coolant. This energy is then available to be transferred to the steam generator with the broken steamline. When applicable, the effects of reverse steam generator heat transfer are included in the results.

5.6.2.2.7 Break Flow Model

Piping discharge resistances are not included in the calculation of the releases resulting from the steamline ruptures (Moody Curve for an $f(\ell / D) = 0$ is used). This maximizes the break flowrate and increases the energy release into the compartment, resulting in a maximum temperature for the assumed break area.

5.6.2.2.8 Steamline Volume Blowdown

There is no contribution to the mass and energy releases from the steam in the secondary plant main steam loop piping and header because the initial volume is saturated steam. With the focus of the MSLB analysis outside containment on maximizing the superheated steam enthalpy, it is presumed that the saturated steam in the loop piping and the header has no adverse effects on the results. The blowdown of the steam in this volume serves to delay the time of tube uncovery in the steam generators and is conservatively ignored.

5.6.2.2.9 Main Steamline Isolation

Steamline isolation is assumed for all steamline break cases since the break location is upstream of the main steamline check valves for BVPS-1. For BVPS-1, the check valve in the faulted steamline is assumed to close instantaneously due to the reverse steam flow created by the depressurization of the steamline in the vicinity of the break.

5.6.2.2.10 Protection System Actuations

The protection systems available to mitigate the effects of a MSLB outside containment include reactor trip, safety injection, and auxiliary feedwater. The protection system actuation signals and associated setpoints that have been modeled in the analysis are identified in Table 5.6.2-4. The setpoints used are conservative values with respect to the plant-specific values delineated in the Technical Specifications for EPU conditions.

5.6.2.2.10.1 BVPS-1 Actuation Signals

For both analyzed break sizes at 100.6 and 70% power with the intent of maximizing the superheated steam release duration, reactor trip is actuated following the Low-Low Steam Generator Water Level signal. Main feedwater flow is assumed to be isolated following reactor trip upon receipt of a low RCS T_{avg} signal. Safety injection is started as a result of a Low Pressurizer Pressure signal. Auxiliary feedwater flow from two motor-driven pumps is initiated following a safety injection signal.

For the analysis for which the "soak time" is extended, main feedwater flow increases to match the increase in the steam flow and no automatic actuation of reactor trip is received from any signal. Operator action at 30 minutes following event initiation is assumed to trip the reactor and isolate the main feedwater system. The change in the transient response for each of the four analyzed steamline break cases is that the mass and energy releases from the faulted-loop steam generator continue until beyond 1800 seconds after event initiation. Tube uncovery and production of superheated steam in the faulted-loop steam generator occur after 1800 seconds and continues until this steam generator dries out.

The turbine stop valve is assumed to close instantly following the reactor trip signal; the delay time used in the steamline break mass and energy releases outside containment is 0.0 seconds.

5.6.2.2.11 Safety Injection System

Minimum safety injection system (SIS) flowrates corresponding to the failure of one SIS train have been assumed in this analysis. A minimum SI flow is conservative since the reduced boron addition maximizes a return to power resulting from the RCS cooldown. The higher power generation increases heat transfer to the secondary side, maximizing steam flow out of the break. The delay time to achieve full SI flow is assumed to be 27 seconds for this analysis with offsite power available. A coincident loss of offsite power is not assumed for the analysis of the steamline break outside containment since the mass and energy releases would be reduced due to the loss of forced reactor coolant flow, resulting in less primary-to-secondary heat transfer.

5.6.2.2.12 Reactor Coolant System Metal Heat Capacity

As the primary side of the plant cools, the temperature of the reactor coolant drops below the temperature of the reactor coolant piping, the reactor vessel, the reactor coolant pumps, and the steam generator thick-metal mass and tubing. As this occurs, the heat stored in the metal is available to be transferred to the steam generator with the broken line. The effects of this RCS metal heat are included in the results using conservative thick-metal masses and heat transfer coefficients.

5.6.2.2.13 Core Decay Heat

Core decay heat generation assumed in calculating the steamline break mass and energy releases is based on the 1979 ANS Decay Heat + 2σ model (Reference 2). The existing analysis assumed the use of the 1971 standard (+20% uncertainty) for the decay heat. The use of the 1979 version represents a deviation from the current licensing-basis MSLB M&E releases outside containment analysis for BVPS-1. This decay heat model has been previously used by Westinghouse in other analyses for the Beaver Valley Power Station including the MSLB M&E releases inside containment analysis previously submitted to the NRC for review and approval as part of the Beaver Valley Power Station Containment Conversion License Amendment Request (LAR) No. 317 (BVPS-1). It has been approved by the NRC for similar applications on other plants.

5.6.2.2.14 Rod Control

The rod control system is conservatively assumed to be in manual operation for all steamline break analyses.

5.6.2.2.15 Core Reactivity Coefficients

Conservative core reactivity coefficients corresponding to end-of-cycle conditions are used to maximize the reactivity feedback effects resulting from the steamline break. Use of maximum reactivity feedback results in higher power generation if the reactor returns to criticality, thus maximizing heat transfer to the secondary side of the steam generators.

5.6.2.3 Description of Analyses and Evaluations

The system transient that provides the break flows and enthalpies of the steam release through the steamline break outside containment has been analyzed with the LOFTRAN (Reference 3) computer code. Blowdown mass and energy releases determined using LOFTRAN include the effects of core power generation, main and auxiliary feedwater additions, engineered safeguards systems, reactor coolant system thick-metal heat storage including steam generator thick-metal mass and tubing, and reverse steam generator heat transfer. The use of the LOFTRAN code for the analysis of the MSLB with superheated steam M&E releases is documented in Supplement 1 of WCAP-8822 (Reference 1), which has been reviewed and approved by the NRC for use in analyzing main steamline breaks, and in Reference 4 for MSLBs outside containment. The LOFTRAN code has been utilized previously for the BVPS-1 licensing-basis safety analyses.

The BVPS-1 NSSS have been analyzed to determine the transient mass releases and associated superheated steam enthalpy values outside containment following a steamline break event. The tables of mass flowrates and steam enthalpies are used as input conditions to the environmental evaluation of safety-related electrical equipment in the main steam valve room.

The following licensing-basis cases of the MSLB outside containment have been analyzed at the noted conditions for the EPU Project.

BVPS-1

For BVPS-1, the following cases have been analyzed.

- At 100.6% power, break sizes of 0.2 and 0.1 ft^2 upstream of the steamline check valve
- At 70% power, break sizes of 0.2 and 0.1 ft^2 upstream of the steamline check valve

Each MSLB outside containment is represented as a nonmechanistic split rupture (crack area). Since the break location is assumed to be upstream of the main steamline check valve, steam releases from only the steam generator in the faulted loop are postulated since reverse steam flow from the other two steam generators is precluded by the closure of the check valve.

5.6.2.4 Acceptance Criteria and Results

The main steamline break is classified as an ANS Condition IV event, an infrequent fault. The acceptance criteria associated with the steamline break event resulting in a mass and energy release outside containment is based on an analysis that provides sufficient conservatism that the equipment qualification temperature envelope is maintained. The specific criteria applicable to this analysis are related to the assumptions regarding power level, stored energy, the break flow model, steamline and feedwater isolation, and main and auxiliary feedwater flow such that superheated steam resulting from tube bundle uncovery in the steam generators is accounted for and maximized. These analysis assumptions have been included in this steamline break mass and energy release analysis as discussed in Section 5.6.2.2 of this report. The tables of mass flowrates and steam enthalpy values for each of the steamline break cases noted in the previous section are used as input to the environmental evaluation of safety-related electrical equipment in the main steam valve room.

Using the MSLB analysis methodology documented in Reference 4 as a basis, including parameter changes associated with the EPU Project, the mass and energy release rates for each of the steamline break cases noted in Section 5.6.2.3 have been developed for use in the environmental evaluation of safety-related electrical equipment in the main steam valve room for BVPS-1. For BVPS-1, Table 5.6.2-5 provides the sequence of events for the various steamline break sizes at 100.6 and 70% power.

5.6.2.5 Conclusions

The mass releases and associated steam enthalpy values from the spectrum of steamline break cases outside containment have been analyzed at the conditions defined by the EPU Project. The assumptions delineated in Section 5.6.2.2 have been included in the steamline break analysis such that conservative mass and energy releases are calculated. The mass releases and associated steam enthalpy values discussed in this section have been provided for use in the environmental evaluation of safety-related electrical equipment in the main steam valve room for BVPS-1 in support of the EPU Project.

The results and conclusions of the analyses performed for MSLB mass and energy releases outside containment for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

5.6.2.6 References

1. WCAP-8822 (Proprietary) and WCAP-8860 (Non-Proprietary), "Mass and Energy Releases Following a Steam Line Rupture," September 1976; WCAP-8822-S1-P-A (Proprietary) and WCAP-8860-S1-A (Non-Proprietary), "Supplement 1 – Calculations of Steam Superheat in Mass/Energy Releases Following a Steam Line Rupture," September 1986; WCAP-8822-S2-P-A (Proprietary) and WCAP-8860-S2-A (Non-Proprietary), "Supplement 2 – Impact of Steam Superheat in Mass/Energy Releases Following a Steam Line Rupture for Dry and Subatmospheric Containment Designs," September 1986.

2. ANSI/ANS-5.1-1979, "American National Standard for Decay Heat Power in Light Water Reactors," August 1979.

3. WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-Proprietary), "LOFTRAN Code Description," April 1984.

4. WCAP-10961, Rev. 1, (Proprietary), "Steamline Break Mass/Energy Releases for Equipment Environmental Qualification Outside Containment, Report to the Westinghouse Owners Group High Energy Line Break/Superheated Blowdowns Outside Containment Subgroup," October 1985.

Table 5.6.2-1
Nominal Plant Parameters for EPU[1]
MSLB M&E Releases Outside Containment

Nominal Conditions	BVPS-1	BVPS-2
NSSS Power, MWt	2910	NA
Core Power, MWt	2900	NA
Reactor Coolant Pump Heat, MWt	10	NA
Reactor Coolant Flow (total), gpm (Thermal Design Flow)	261,600	NA
Pressurizer Pressure, psia	2250	NA
Core Bypass, %	6.5	NA
Reactor Coolant Vessel Average Temperature, °F	580.0	NA
Steam Generator[2]		
Steam Temperature, °F	522.6	NA
Steam Pressure, psia	831	NA
Steam Flow, 10^6 lbm/hr (Plant Total)	13.04	NA
Feedwater Temperature, °F	455	NA
Zero-Load Temperature, °F	547	NA

Notes:

(1) Noted values correspond to plant conditions defined by 0% steam generator tube plugging and the high end of the RCS T_{avg} window.

(2) Steam generator performance data used in the analysis are conservatively high for steam temperature and pressure.

Table 5.6.2-2
Initial Condition Assumptions for EPU[1]
MSLB M&E Releases Outside Containment

Initial Conditions	BVPS-1		BVPS-2	
Power Level (%)	100.6	70	NA	NA
RCS Average Temperature (°F)	588.5	578.6	NA	NA
RCS Flowrate (gpm) (Thermal Design Flow)	261,600	261,600	NA	NA
RCS Pressure (psia)	2250	2250	NA	NA
Pressurizer Water Volume (ft^3)	834.3	693.3	NA	NA
Feedwater Enthalpy (Btu/lbm)	436.0	385.4	NA	NA
SG Pressure (psia)[2]	893	948	NA	NA
SG Water Level, Maximum Superheat (% NRS) (minimum) (nominal)	 55 65	 55 65	NA	NA
SG Water Level, Increased Soak Time (% NRS) (minimum) (nominal)	 NA 44[3]	 NA 44[3]	NA	NA

Notes:

(1) Noted values correspond to plant conditions defined by 0% steam generator tube plugging and the high end of the RCS T_{avg} window; temperatures include applicable uncertainties.

(2) The noted SG pressures are determined at the steady-state conditions defined by the RCS average temperatures, including applicable uncertainties.

(3) The noted SG water level is for the BVPS-1 OSGs. The resulting MSLB M&E releases outside containment bound and support the BVPS-1 RSGs.

Table 5.6.2-3
Main and Auxiliary Feedwater System Assumptions for EPU
MSLB M&E Releases Outside Containment

Parameter	BVPS-1	BVPS-2
Main Feedwater System		NA
Flowrate – both power levels (maximizing superheat)	nominal flow to all loops	
Flowrate – both power levels (extended soak time)	increased flow to match steam flow	
Unisolable volume from SG nozzle to FIV	none assumed	
Auxiliary Feedwater System		NA
Flowrate to all steam generators	Minimum flow to each SG. The actual data used is a function of SG pressure.	
Temperature (maximum value), °F	120	
Piping purge volume (faulted loop), ft^3	168	
Actuation delay time (maximizing superheat), seconds	60	
Actuation delay time (extended soak time), seconds	0	

Table 5.6.2-4
Protection System Actuation Signals and Safety System Setpoints for EPU MSLB M&E Releases Outside Containment

Actuation Signal	BVPS-1	BVPS-2
Reactor Trip		NA
2/3 Low-Low Steam Generator Water Level in any loop, % narrow-range span	0	
2/3 Low Pressurizer Pressure, psia	1935	
2/4 Power-Range High Neutron Flux, % rated thermal power	118	
2/3 Overtemperature ΔT		
K1	1.330(1)	
K2	0.0183	
K3	0.001	
Dynamic compensation lead, seconds	30	
Dynamic compensation lag, seconds	4	
2/3 Overpower ΔT		
K4	1.146(1)	
K5	0.0(2)	
K6	0.0021	
Dynamic compensation rate lag, seconds	10	
Safety Injection	Yes	
Safety Injection		NA
2/3 Low Pressurizer Pressure, psia	1745	
2/3 Low Steamline Pressure in any loop, psia	460	
Dynamic compensation lead, seconds	50	
Dynamic compensation lag, seconds	5	
Steamline Isolation		NA
2/3 Low Steamline Pressure in any loop, psia	460	
Dynamic compensation lead, seconds	50	
Dynamic compensation lag, seconds	5	
Feedwater Isolation		NA
Low RCS Average Temperature following a Reactor Trip, °F	557	
Safety Injection	Yes	
Auxiliary Feedwater Initiation (motor-driven AFW pumps)		NA
Safety Injection	Yes	

Notes:
(1) Where applicable, K1 = 1.34157 and/or K4 = 1.15597 were used to account for RCS temperature asymmetry.
(2) K5 = 0.0 for decreasing temperature is applicable to MSLB M&E releases outside containment analysis.

Table 5.6.2-5
BVPS-1 Transient Summary for the Spectrum of Breaks Outside Containment

Power Level (% nom)	Break Size (ft^2)	Reactor Trip Signal	Rod Motion (sec)	Safety Injection Signal	Safety Injection (sec)	Feedwater Isolation (sec)	Steamline Isolation (sec)	Auxiliary Feedwater (sec)	SG Tube Uncovery (sec)
Mass and Energy Releases Calculated to Maximize the Steam Enthalpy (Maximum Superheat)									
100.6	0.2	LSGWL	210.2	LPP	344.5	282.7(1)	NA	404.5	619.0
100.6	0.1	LSGWL	408.8	LPP	881.1	497.0(1)	NA	941.1	1159.
70	0.2	LSGWL	188.2	LPP	368.5	228.5(1)	NA	428.5	428.8
70	0.1	LSGWL	364.5	LPP	880.3	413.9(1)	NA	940.4	860.2
Mass and Energy Releases Calculated to Increase the Soak Time and Maximize the Total Energy									
100.6	0.2	Manual	1800.	NA	-----	1800.	NA	NA	2055.
100.6	0.1	Manual	1800.	NA	-----	1800.	NA	NA	2209.
70	0.2	Manual	1800.	NA	-----	1800.	NA	NA	2136.
70	0.1	Manual	1800.	NA	-----	1800.	NA	NA	2333.

Note:
(1) Main feedwater isolation function generated by an RCS low T_{avg} signal following reactor trip

Key LPP – low pressurizer pressure
LSGWL – low-low steam generator water level
NA – not applicable

Table 5.6.2-6
BVPS-2 Transient Summary for the Spectrum of Breaks Outside Containment
Maximum Superheat (EPU Table)

(This table number is included to maintain numbering consistency with the EPU Licensing Report. The information in this table is not applicable for the RSG Licensing Report.)

Table 5.6.2-7
BVPS-2 Transient Summary for the Spectrum of Breaks Outside Containment
Increased Soak Time – Reduced Superheat (EPU Table)

(This table number is included to maintain numbering consistency with the EPU Licensing Report. The information in this table is not applicable for the RSG Licensing Report.)

Table 5.6.2-8
BVPS-2 Mass and Energy Releases Calculated to Maximize the Steam Enthalpy
with Faulted-Loop MSIV Operational (EPU Table)

(This table number is included to maintain numbering consistency with the EPU Licensing Report. The information in this table is not applicable for the RSG Licensing Report.)

5.6.3 Steam Releases for Radiological Dose Analysis

5.6.3.1 Introduction

In support of radiological dose analyses, steam and radioactivity releases to the environment are postulated to occur via the following scenarios.

- An activity level exists in the reactor coolant system (RCS):The activity level in the RCS may be low, resulting from activated corrosion products or from the potential minute release of fission material from defective fuel assemblies. The activity level may also be moderate to high, resulting from potential fuel cladding failures and the subsequent fission product release.

- A primary-to-secondary leak occurs: The most common primary-to-secondary leak would be a leak through the wall of one or more steam generator tubes. A maximum allowable leak rate is specified in the Technical Specifications based on tube integrity requirements. The Technical Specifications leakage limit is used to determine radioactivity releases to the environment.

- Secondary-side activity is released into the atmosphere: Given that a primary-to-secondary leak exists and the condenser is not available for steam dump following an accident that produces a reactor trip, steam and radioactivity will be released through the atmospheric dump valves while the plant is being brought to a cold shutdown condition. The Loss of Non-Emergency AC Power event, and other events that result in a loss-of-offsite power, are situations that result in the unavailability of the condenser.

Vented steam releases have been calculated for the Loss of Non-Emergency AC Power, Locked Rotor, and Steamline Break events to support the EPU Project.

5.6.3.2 Input Parameters and Assumptions

The following general assumptions associated with EPU have been used in the calculation of the steam releases and feedwater flows.

- NSSS power (2910 MWt) plus 0.6% uncertainty

- RCS average temperature (580.0°F)

- Nominal RCS pressure (2250 psia)

- Steam generator tube plugging is chosen to maximize secondary-side mass inventory. The operating conditions used in this analysis reflect the high end of the T_{avg} RCS temperature range, high secondary-side (steam) temperature, the low end of the main feedwater temperature range, and no steam generator tube plugging.

- Nominal steam temperature (522.6°F) for BVPS-1 with the Model 54F replacement steam generators (RSGs).

- An 11.6% blowdown of the lowest setpoint of the main steam safety valves. This reduces the saturation temperature in the steam generators and lowers the RCS temperature to the corresponding saturation temperature.
- RCS volumes and thick-metal masses associated with the Model 54F RSGs for BVPS-1.
- Residual heat removal cut-in conditions of 350°F and 375 psia.
- Steam releases are determined for the intervals 0 to 2 hours and 2 to 8 hours.

Steam dump will be required until the reactor can be placed on the residual heat removal (RHR) system. It has been confirmed that eight hours of steam release could occur prior to placing the plant in the RHR mode of operation. After the first 2 hours, it is assumed the plant will have cooled down and stabilized at no-load conditions. The additional 6 hours are required to cool down and depressurize the plant from no-load conditions to the RHR operating conditions.

An assumption in this analysis is that the entire inventory of the steam generators is released to the environment and no loss of inventory through the blowdown line is accounted for. This provides a conservative calculation of the quantity of steam vented during the noted time periods.

5.6.3.3 Description of Analyses and Evaluations

The amount of steam released to the atmosphere depends on the sensible heat and decay heat generated while reducing the temperature from the full-power value to the shutdown conditions. No computer program is used for this calculation. A hand calculation is performed to determine the amount of steam that is dissipated through the atmospheric steam release.

The total RCS energy at the end of the first 2 hour interval is subtracted from the sum of the initial RCS energy and the decay heat generated during this interval. For the Steamline Break event, it is conservative to assume that the contents of the faulted-loop steam generator blow down within the first 2 hours with no energy extraction from the RCS (i.e., no temperature decrease) due to the blowdown. Likewise, the total RCS energy at the end of the 2 to 8 hour interval is subtracted from the sum of the RCS energy and the decay heat generated during this 6 hour interval.

An energy balance during both of these intervals is used to calculate the mass of auxiliary feedwater injected during the cooldown interval. The mass of feedwater injected is used to calculate the steam mass vented to the environment through the intact-loop steam generators. For the Loss of Non-Emergency AC Power and Locked Rotor events, three intact loops have been used in the steam release calculations; for the Steamline Break event, two intact loops have been used for this calculation. An additional calculation is performed for the Steamline Break event in which the contents of the faulted-loop steam generator blow down during the first 2 hour interval.

5.6.3.4 Acceptance Criteria

There are no specific acceptance criteria associated with the calculation of the steam releases and feedwater flows used as input to the radiological dose analysis. Tables of steam releases and feedwater

flows for each of the cooldown intervals for each of these three transients are used as input to the radiological dose analysis in support of the EPU Project.

5.6.3.5 Results

Table 5.6.3-1 summarizes for BVPS-1 the vented steam releases from the intact-loop steam generators as well as feedwater flows for the 0 to 2 hour time period and the 2 to 8 hour time period for the Loss of Non-Emergency AC Power, Locked Rotor, and Steamline Break events. These two time periods are documented to support the EPU Project.

For the Steamline Break event, additional steam is released through the faulted-loop steam generator from the initiation of the transient up through the time at which the faulted loop is isolated from main and auxiliary feedwater flows. The steam mass from the faulted-loop steam generator is 163,150 lbm for the BVPS-1 Model 54F RSGs. This steam mass is not included in the data presented in Table 5.6.3-1.

The steam releases discussed in this section are used as input to the radiological dose analysis in support of the EPU Project.

5.6.3.6 Conclusions

The steam releases and feedwater flows have been calculated at the conditions defined for EPU for the Loss of Non-Emergency AC Power, Locked Rotor, and Steamline Break events. The assumptions delineated in Section 5.6.3.2 have been included in the steam release calculations for each transient such that the results are consistent with and continue to comply with the current licensing-basis and acceptance requirements. The steam releases and feedwater flows discussed in this section have been provided for use in the radiological dose analysis to support the EPU Project.

The results and conclusions of the analyses performed for steam releases for radiological doses for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

Table 5.6.3-1
BVPS-1 Steam Releases and Auxiliary Feedwater Flows with Model 54F RSGs

Event	Steam Release (lbm)		Feedwater Flow (lbm)	
	0 to 2 hours	2 to 8 hours	0 to 2 hours	2 to 8 hours
Loss of Non-Emergency AC Power and Locked Rotor	340,000	778,000	511,000	789,000
Steamline Break	345,000	734,000	458,000	742,000

Table 5.6.3-2
BVPS-2 Steam Releases and Auxiliary Feedwater Flows with OSGs (EPU Table)

(This table number is included to maintain numbering consistency with the EPU Licensing Report. The information in this table is not applicable for the RSG Licensing Report.)

5.7 LOCA HYDRAULIC FORCES (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.9 NATURAL CIRCULATION AND COOLDOWN (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.10 REACTOR TRIP SYSTEM/ENGINEERED SAFETY FEATURE ACTUATION SYSTEM SETPOINTS

5.10.1 Introduction

The Technical Specification and Core Operating Limits Report (COLR) Reactor Trip System (RTS)/Engineered Safety Feature Actuation System (ESFAS) setpoints have been reviewed for operation at EPU conditions. As part of the review, Technical Specification and/or COLR changes have been identified consistent with the Westinghouse setpoint methodology.

5.10.2 Description of Analyses and Evaluations

The setpoint analysis uses the Square-Root-Sum-of-the-Squares (SRSS) technique to combine the uncertainty components of an instrument channel in an appropriate combination of those components, or groups of components, which are statistically independent. Those uncertainties that are not independent are arithmetically summed to produce groups that are independent of each other, which can then be statistically combined. The methodology used for the EPU conditions is defined in Reference 1 for BVPS-1 and is the same as was used for the NRC approved 1.4% measurement uncertainty recapture power uprate.

5.10.3 Acceptance Criteria and Results

Margin is defined as the difference between the Total Allowance (TA) and the Channel Statistical Allowance (CSA). Total Allowance is the difference between the limiting UFSAR safety analysis limit and the Technical Specification/COLR Trip Setpoint (in percent of instrument span). Channel Statistical Allowance is the statistical combination of the instrument channel uncertainty components (in percent of instrument span). The acceptance criterion for the RTS/ESFAS setpoints is that margin is greater than or equal to zero.

The only RTS/ESFAS functions and setpoints impacted by EPU are those for Overtemperature ΔT and Overpower ΔT reactor trip. The equations, setpoints, and time constants for these RTS functions were

revised to optimize operating margins at EPU conditions as described in Section 3.2.1 of this report. Table 5.10-1 shows the current and EPU values for Overtemperature ΔT and Overpower ΔT setpoints and time constants, including the Overtemperature ΔT and Overpower ΔT equations for EPU.

For BVPS-1, the Model 54F replacement steam generators (RSGs) impact the RTS/ESFAS functions and setpoints for the steam generator low-low water level reactor trip and auxiliary feedwater actuation and the steam generator high-high water level turbine trip and feedwater isolation actuation. The setpoints for these RTS/ESFAS functions were revised to address the design of the Model 54F RSGs, and to optimize operating margins at EPU conditions with the Model 54F RSGs. Table 5.10-2 shows the RTS/ESFAS steam generator level setpoints for the BVPS-1 Model 54F RSGs at EPU conditions. The RTS/ESFAS steam generator low-low and high-high water level setpoints are calculated consistent with the recommendations in Nuclear Safety Advisory Letter (NSAL) NSAL-03-9 (Reference 3) and Technical Bulletin (TB) TB-04-12 (Reference 4). Consistent with the recommendations in References 3 and 4, the steam generator water level uncertainties for small/intermediate feedline breaks reflect inside containment environmental conditions corresponding to a limiting T_{sat} equivalent to the containment pressure high trip setpoint plus instrument uncertainties. Thus, steam generator water level low-low trip is credited as the actuation function for small/intermediate feedline breaks that result in containment pressures less than the containment pressure high trip setpoint (plus uncertainties) and containment pressure high will actuate reactor trip and safety injection, and thus start auxiliary feedwater, for small/intermediate feedline breaks that result in containment pressures greater than the containment pressure high trip setpoint. This limits the elevated temperature conditions the steam generator water level low-low trip function instrumentation experiences while mitigating inside containment small/intermediate feedline breaks.

Incorporating these Technical Specification/COLR changes will support operation at EPU conditions in a manner consistent with the UFSAR assumptions. Functions not listed do not change as a result of the EPU conditions. The results of the RTS/ESFAS setpoint analysis are provided in Reference 1 for BVPS-1.

5.10.4 Conclusions

With the setpoint changes as shown on Table 5.10-1 and Table 5.10-2, all of the RTS/ESFAS functions have acceptable margins and therefore are acceptable for the NSSS power of 2910 MWt.

The results and conclusions of the analyses and evaluations performed for RTS/ESFAS setpoints for the reactor power of 2900 MWt (2910 MWt NSSS power) bound and support operation at the current reactor power of 2689 MWt (2697 MWt NSSS power).

5.10.5 References

1. WCAP-11419, Rev. 4, "Westinghouse Setpoint Methodology for Protection Systems Beaver Valley Power Station Unit 1," March 2004.

2. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

3. NSAL-03-9, "Steam Generator Water Level Uncertainties," September 22, 2003.

4. TB-04-12, "Steam Generator Level Process Pressure Evaluation," June 23, 2004.

Table 5.10-1
Summary of the Technical Specification/COLR RTS/ESFAS Setpoint Changes for OTΔT and OPΔT

Parameter	BVPS-1				BVPS-2			
	Trip Setpoint		Allowable Value		Trip Setpoint		Allowable Value	
	Current Value	EPU Value	Current Value	EPU Value	Current Value	EPU Value	Current Value	EPU Value
	Overtemperature ΔT Reactor Trip[1]				Overtemperature ΔT Reactor Trip[2]			
K_1 (nominal)	1.259	1.242	≤0.5% ΔT span for ΔT, ≤0.5% ΔT span for T_{avg}, ≤0.5% ΔT span for Pressure, ≤0.5% ΔT span for ΔI	≤0.5% ΔT span for ΔT, ≤0.5% ΔT span for T_{avg}, ≤0.5% ΔT span for Pressure, ≤0.5% ΔT span for ΔI	NA	NA	NA	NA
K_2	0.01655/°F	0.0183/°F	N/A	N/A	NA	NA	NA	NA
K_3	0.000801/psi	0.001/psi	N/A	N/A	NA	NA	NA	NA
T'	Reference T_{avg} ≤576.2°F	Reference T_{avg} ≤580.0°F	N/A	N/A	NA	NA	NA	NA
+ΔI Gain	1.59	1.47	N/A	N/A	NA	NA	NA	NA
-ΔI Gain	2.08	4.67	N/A	N/A	NA	NA	NA	NA
f(ΔI) Penalty Dead-band	-36% to +15%	-48% to +10%	N/A	N/A	NA	NA	NA	NA
τ_1	30 seconds	30 seconds	N/A	N/A	NA	NA	NA	NA
τ_2	4 seconds	4 seconds	N/A	N/A	NA	NA	NA	NA
τ_3	N/A	N/A	N/A	N/A	NA	NA	NA	NA
τ_4	N/A	6 seconds	N/A	N/A	NA	NA	NA	NA
τ_5	N/A	2 seconds	N/A	N/A	NA	NA	NA	NA
τ_6	N/A	N/A	N/A	N/A	NA	NA	NA	NA

Table 5.10-1 (continued)
Summary of the Technical Specification/COLR RTS/ESFAS Setpoint Changes for OTΔT and OPΔT

Parameter	BVPS-1				BVPS-2			
	Trip Setpoint		Allowable Value		Trip Setpoint		Allowable Value	
	Current Value	EPU Value	Current Value	EPU Value	Current Value	EPU Value	Current Value	EPU Value
	Overpower ΔT Reactor Trip[3]				Overpower ΔT Reactor Trip[4]			
K4 (nominal)	1.0916	1.085	≤0.5% ΔT span for ΔT, ≤0.5% ΔT span for T_{avg}	≤0.5% ΔT span for ΔT, ≤0.5% ΔT span for T_{avg}	NA	NA	NA	NA
K5	0.02/°F for increasing T_{avg}, 0 for decreasing T_{avg}	0.02/°F for increasing T_{avg}, 0 for decreasing T_{avg}	N/A	N/A	NA	NA	NA	NA
K6	0.00128/°F for T>T", 0 for T≤T"	0.0021/°F for T>T", 0 for T≤T"	N/A	N/A	NA	NA	NA	NA
T"	Reference T_{avg} ≤576.2°F	Reference T_{avg} ≤580.0°F	N/A	N/A	NA	NA	NA	NA
τ_1	N/A	N/A	N/A	N/A	NA	NA	NA	NA
τ_2	N/A	N/A	N/A	N/A	NA	NA	NA	NA
τ_3	0 seconds	10 seconds	N/A	N/A	NA	NA	NA	NA
τ_4	N/A	6 seconds	N/A	N/A	NA	NA	NA	NA
τ_5	N/A	2 seconds	N/A	N/A	NA	NA	NA	NA
τ_6	N/A	N/A	N/A	N/A	NA	NA	NA	NA
τ_7	N/A	N/A	N/A	N/A	NA	NA	NA	NA

Table 5.10-1 (continued)
Summary of the Technical Specification/COLR RTS/ESFAS Setpoint Changes for OTΔT and OPΔT

Notes:

(1) BVPS-1 OTΔT Equation for EPU:

$$\Delta T \frac{1}{(1+\tau_4 s)} \leq \Delta T_0 \{K_1 - K_2 \frac{(1+\tau_1 s)}{(1+\tau_2 s)} [T \frac{1}{(1+\tau_5 s)} - T'] + K_3 (P - P') - f(\Delta I)\}$$

(2) NA

(3) BVPS-1 OPΔT Equation for EPU:

$$\Delta T \frac{1}{(1+\tau_4 s)} \leq \Delta T_0 \{K_4 - K_5 \frac{\tau_3 s}{(1+\tau_3 s)} [T \frac{1}{(1+\tau_5 s)}] - K_6 [T \frac{1}{(1+\tau_5 s)} - T'']\}$$

(4) NA

Table 5.10-2
BVPS-1 Summary of the Technical Specification/COLR
RTS/ESFAS Setpoint Changes for Steam Generator Water Level

Parameter	Trip Setpoint	Allowable Value
Steam Generator Low-Low Water Level, % NRS	19.6(1)	≥ 19.1(1)
Steam Generator High-High Water Level, % NRS	89.7(1)	≤ 90.2(1)

Note:

(1) The steam generator low-low and high-high water level setpoints and allowable values are calculated consistent with the recommendations in Nuclear Safety Advisory Letter NSAL-03-9 (Reference 3) and Technical Bulletin TB-04-12 (Reference 4).

5.11 RADIOLOGICAL ASSESSMENTS

The radiological impact of EPU is addressed in Section 5.11 of the EPU Licensing Report (Enclosure 2 of EPU LAR 302/173). In addition to EPU, the analyses considered containment conversion, use of replacement steam generators (RSGs) at BVPS-1, and complete implementation of Alternative Source Terms (AST) at BVPS-1 and 2.

The purpose of this section is to summarize the radiological assessments supporting RSG implementation at BVPS-1 including those portions of the EPU radiological analyses/evaluations that are relevant to:

a) Use of replacement steam generators (RSGs) at BVPS-1, and

b) Expansion of selective implementation of AST at BVPS-1 to include all accidents affected by the use of the BVPS-1 RSGs.

For purposes of consistency with EPU LAR 302/173, if a radiological topic is affected by either of these issues at BVPS-1, the entire discussion of that subject in the EPU LAR 302/173 is included herein.

The material presented in this section takes into consideration the following:

- The impact of RSGs at BVPS-1 on the primary and secondary coolant radioactivity concentrations at the current licensed power level and the associated affect on a) plant radiation levels and shielding adequacy, b) the normal operation component of the estimated environmental dose utilized for equipment qualification, c) normal operation annual radwaste effluent releases.

- The impact of RSGs at BVPS-1 with the conservative assumption of EPU conditions on the a) primary and secondary coolant technical specification radioactivity concentrations, b) post accident thermo-hydraulic transient and associated environmental releases from the steam generators, either via a broken main steam line, or via the steam generator MSSVs/ADVs prior to the initiation of shutdown cooling; and the associated affect on the dose consequences at the site boundary and control room.

- Expansion of selective implementation of AST at BVPS-1 to include all accidents affected by the use of the BVPS-1 RSGs.

- Conservative use of the BVPS-1 EPU (with RSGs) site boundary and dose consequence analyses previously submitted in EPU LAR 302/173, to demonstrate compliance with the regulatory limits following implementation of RSGs at the current power level.

- Note that several of the assessments performed in support of EPU with RSGs utilize bounding parameter values to encompass an event at/or operation of either BVPS unit. Consequently, for these assessments the BVPS-2 input parameters, description of assessments, and associated results are included

5.11.1 Introduction

This section addresses the radiological impact of the RSGs at Beaver Valley Power Station Unit 1 (BVPS-1). The current licensing basis core power level is 2689 MWt. Site boundary and control room dose consequences presented herein are based on EPU conditions. The EPU core power level is 2900 MWt. The EPU NSSS power level is 2910 MWt which includes an additional 10 MWt of net heat input from operation of the reactor coolant pumps.

Additionally, as holder of operating licenses issued prior to January 10, 1997, and in accordance with 10 CFR 50.67 (Reference 1) and Standard Review Plan 15.0.1 (Reference 2), the accident source terms used in the BVPS-1 RSG design basis site boundary and control room dose analyses have been revised to reflect the expansion of selective implementation of Alternative Source Terms (AST) as detailed in Regulatory Guide 1.183 (Reference 3) to all accidents affected by RSG implementation.

The first use of the AST for BVPS was a selective application to revise the Fuel Handling Accident (FHA) in order to justify certain changes in plant operation and configuration during fuel movements. The analysis was reviewed and approved by the NRC in its SER for OL Amendment No. 241 (Reference 4). In June 2002, the selective application of AST at BVPS was expanded by Reference 5 to include those accidents (i.e., the Loss of Coolant Accident and the Control Rod Ejection Accident) that were impacted by the change in BVPS containment operating conditions from sub-atmospheric to atmospheric pressure (i.e., containment conversion). The expansion of the selective application of AST at BVPS, submitted by Reference 5, was approved by the NRC in its SER for OL Amendment No. 257 (Reference 38). Reference 5 also contained an application for containment conversion that was withdrawn by FENOC letter L-03-135, dated September 5, 2003 (Reference 39). A revised application for containment conversion has been submitted to the NRC for review and approval as License Amendment Request No. 317.

The radiological impact of RSG implementation is evaluated for the following:

- Normal Operation Dose Rates and Shielding
- Normal Operation Annual Radwaste Effluent Releases
- Radiological Environmental Doses for Equipment Qualification (EQ)
- Post-LOCA Access to Vital Areas
- Post-Accident Site Boundary and Control Room Doses

In accordance with regulatory guidance, radiological evaluations for site boundary and control room dose consequences are assessed at a core power level of 2918 MWt to include an uncertainty of 0.6% to the EPU power level. Installation of improved feedwater measurement instrumentation used for calorimetric power calculation allows for instrument error to be reduced from the traditional 2% as recommended in Regulatory Guide 1.49 (Reference 6). The reduction of the uncertainty allowance for calorimetric thermal power measurement to 0.6% was approved by the NRC in its SER for the License Amendment No. 243 (Reference 7).

The impact of RSGs on the site boundary and control room doses are discussed for the following accidents applicable to BVPS licensing basis:

1. Loss of Coolant Accident (LOCA) (NA, EPU only)
2. Control Rod Ejection Accident (CREA)
3. Main Steam Line Break (MSLB) outside Containment
4. Steam Generator Tube Rupture (SGTR)
5. Locked Rotor Accident (LRA)
6. Loss of AC Power (LACP)
7. Fuel Handling Accident (FHA) in the Fuel Pool or in Containment (NA, EPU only)
8. Small Line Break (SLB) Outside Containment
9. Waste Gas System Rupture (WGSR) (NA, EPU only)

Note that the CREA is addressed in this application by reference only, since these accident analyses was performed assuming RSGs and EPU conditions and was approved by License Amendment No. 257. The Loss of Coolant Accident (LOCA) and the Fuel Handling Accident (FHA) are not impacted by the RSGs. The impact of RSGs on the Waste Gas System Rupture (WGSR) is deemed negligible based on current licensing basis. The change in primary coolant mass due to the RSGs have minimal impact on the current design primary coolant source terms; consequently, the RSGs will have negligible impact on the dose consequences at the site boundary and control room following a WGSR.

At BVPS, the SLB Outside Containment, LACP, MSLB, and SGTR are not directly impacted by the implementation of the AST as there is no accident initiated fuel damage associated with these events. However, this application extends the selective implementation of AST at BVPS-1 and the dose acceptance criteria of 10 CFR 50.67 become applicable to the accidents listed in Regulatory Guide 1.183 which include the MSLB, and the SGTR. It is noted that the SLB Outside Containment and the LACP are not addressed in Regulatory Guide 1.183. The dose criteria to which they are evaluated are discussed in Section 5.11.2.

The updated site boundary and control room dose analyses reflect EPU conditions, AST (as applicable), and except as noted, bounding parameter values to encompass an event at either unit. In addition the parameter values assigned to the BVPS-1 steam generators reflect the Replacement Steam Generators. The MSLB and the SGTR dose analyses are unit specific. Alternate Repair Criteria (ARC) is not utilized in the BVPS-1 EPU MSLB dose analysis because it is not applicable to the Model 54F Replacement Steam Generators. The SGTR dose analyses for BVPS-1 reflect environmental releases based on the licensing basis mass and energy release calculation methodology.

It is noted that the control room dose analyses reflect a control room design consistent with that approved by the NRC in its SER for OL Amendment No. 257. Specifically, the approved design changes include:

- Conservative estimates of control room unfiltered inleakage that envelope the results of recent tracer gas testing performed in the year 2001, and provide margin for surveillance tests.

- Revised Technical Specification acceptance criteria for the BVPS-1 control room HEPA and charcoal filters which make the BVPS-1 acceptance criteria similar to the more limiting criteria for the BVPS-2 control room filters.

- Elimination of credit for the automatic initiation feature of the safety related control room area radiation monitors to initiate the control room emergency pressurization system.

- For those events that take credit for the control room emergency ventilation system (CREVS), manual initiation of CREVS pressurization occurs such that the control room is pressurized by T=30 mins.

- Updated control room atmospheric dispersion factors using ARCON96 methodology.

In addition, the BVPS-1 MSLB and SGTR take credit for a 30 minute control room purge after the accident sequence is complete and the environmental release has been terminated.

The analyses and evaluations for EPU conditions bound and support operation at the current power level.

5.11.2 Regulatory Approach

Summarized below are the regulatory acceptance criteria being utilized for the RSG assessments.

5.11.2.1 Normal Operation Assessments

The regulatory commitments currently associated with normal operation assessments are not impacted by this application and remain applicable for the RSG assessment:

- Normal operation on-site dose rates/available shielding will meet the requirements of 10 CFR 20 (Reference 16) as it relates to allowable operator exposure and access control

- Normal operation off-site releases and doses will meet the requirements of 10 CFR 20 and 10 CFR 50, Appendix I (Reference 17). Performance and operation of installed equipment and reporting of offsite releases and doses will continue to be controlled by the requirements of the Technical Specifications and the Offsite Dose Calculation Manual.

5.11.2.2 Accident Assessments

The regulatory commitments associated with accident assessments are revised as noted by this application and are summarized below:

- Site Boundary and Control Room Doses: As part of the RSG application, BVPS proposes expansion of selective implementation of the AST as defined in RG 1.183, Section 1.2.2 to include all accidents affected by the RSGs (MSLB, SGTR, LRA, LACP, CREA and SLB).

  The acceptance criteria for the Exclusion Area Boundary (EAB) and Low Population Zone (LPZ) doses are based on 10 CFR Part 50 § 50.67 and Section 4.4 Table 6 of Regulatory Guide 1.183 (also noted in Table 1 of SRP 15.0.1):

  - An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release, should not receive a

radiation dose in excess of the accident specific total effective dose equivalent (TEDE) value noted in Reference 3, Table 6.

- An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), should not receive a radiation dose in excess of the accident specific TEDE value noted in Reference 3, Table 6.

Notes: Since the following event is not specifically addressed in RG 1.183:

a. (NA, EPU only)

b. The acceptance criterion utilized for the SLB outside containment and the LACP represent the most limiting dose criterion in Table 6 of RG 1.183.

The acceptance criteria for the Control Room Dose are based on 10 CFR Part 50 § 50.67:

- Adequate radiation protection is provided to permit occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) total effective dose equivalent (TEDE) for the duration of the accident.

- Equipment Qualification: The regulatory commitments currently associated with determination of radiological environments for purposes of equipment qualification are not impacted by this application and remain applicable for the RSG assessment.

- Vital Access Doses: The regulatory commitments currently associated with determination of radiological environments for purposes of vital area access are not impacted by this application and remain applicable for the RSG assessment.

5.11.3 Computer Codes

The QA Category 1 computer codes utilized in EPU analyses that support this application, are listed below. The referenced computer codes have been used extensively to support nuclear power plant design and are a part of BVPS current licensing basis.

1. S&W Proprietary Computer Program RADIOISOTOPE, NU-007, V01, L03.

2. Industry Computer Code ARCON96, "Atmospheric Relative Concentrations in Building Wakes" developed by PNL (S&W Program EN-292, V00, L00).

3. S&W Proprietary Computer Code, PERC2, "Passive Evolutionary Regulatory Consequence Code," NU-226, V00, L01.

4. (NA, EPU only).

5.11.4 Radiation Source Terms

5.11.4.1 Core Inventory

The equilibrium core inventory utilized to support the assessment of dose consequences at the site boundary and control room due to RSGs are based on EPU conditions and reflect a core power level of 2918 MWt, and current licensed values of fuel enrichment and burnup. The methodology used to develop the core inventory, and the associated isotopic listing, is presented in Section 5.3.3.1 and Table 5.3.3-1 of Reference 5.

5.11.4.2 Coolant Inventory

The design basis primary coolant concentrations and the Technical Specification primary and secondary coolant concentrations utilized to support the assessment of dose consequences at the site boundary and control room due to RSGs are based on EPU conditions and reflect an equilibrium core inventory based on a core power level of 2918 MWt, and current licensed values of fuel enrichment and burnup. The methodology to develop the design basis and Technical Specification coolant concentrations is discussed Section 5.3.3.2 of Reference 5.

In accordance with the proposed Technical Specification changes accompanying the EPU amendment request (EPU LAR 302/173), the primary and secondary coolant concentrations for BVPS-1 are assumed to be similar to BVPS-2, which is conservative for operation of the plant prior to changing the Technical Specifications. The primary and secondary coolant iodine activity limits assumed in the analyses compare to the Technical Specification limits as follows:

Technical Specification	Current Limit µCi/gm	Assumed Limit[1] µCi/gm
3.4.8 – Reactor Coolant Systems Specific Activity	0.10	0.35
3.7.1.4 – Plant Systems Activity	0.05	0.10
Note: 1. Proposed in EPU LAR 302/173		

The assumed noble gas and halogen primary and secondary coolant activity concentrations for BVPS-1 are presented herein in Table 5.11.4-1.

5.11.4.3 Primary Coolant Iodine Concentrations based on Pre-Accident/Accident Initiated Iodine Spike

In accordance with the current BVPS-2 Technical Specifications and the conservative assumptions for BVPS-1, the pre-accident iodine spike concentrations in the reactor coolant is 21 µCi/gm DE I-131 (transient Technical Specification limit for full power operation) or 60 times (based on Reference 3) the reactor coolant iodine Technical Specification concentrations.

The accident generated iodine spike activities in the reactor coolant are based on an accident dependent multiplier, times the equilibrium iodine appearance rate. The equilibrium appearance rates are conservatively calculated based on the Technical Specification reactor coolant activities, along with the maximum design letdown rate, maximum Technical Specification allowed leakage, and an ion-exchanger iodine removal efficiency of 100%. Maximizing the reactor coolant cleanup results in maximizing the equilibrium iodine appearance rates.

The pre-accident iodine spike concentrations and the equilibrium iodine appearance rates (utilized to develop accident initiated iodine spike values) assumed for both BVPS-1 and BVPS-2 are presented herein in Table 5.11.4-2.

5.11.4.4 Gap Fractions for Non-LOCA Events

Table 3 in Regulatory Guide 1.183, specifies the fraction of fission product inventory in the fuel rod gap to be used for non-LOCA accidents. The footnote identifies that the applicability of Table 3 is limited to LWR fuel with peak burnups of 62 GWD/MTU "provided that the maximum linear heat generation rate does not exceed 6.3 kW/ft peak rod average power for burnups exceeding 54 GWD/MTU." The gap fractions utilized for the non-LOCA events at BVPS which could result in fuel failure, are consistent with the requirements for RG 1.183 and are listed below.

Nuclide Group	Regulatory Guide 1.183 Gap Fraction for Non-LOCA Events
I-131	0.08
Kr-85	0.10
Other Noble Gases	0.05
Other Halogens	0.05
Alkali Metals	0.12

The core inventory of noble gases, halogens and alkali metals are presented herein in Table 5.11.4-3. These values are consistent with the values presented for these isotopes in Table 5.3.3-1 of Reference 5.

5.11.5 Normal Operation Dose Rates and Shielding

RSGs will have negligible impact on on-site normal operation radiation levels. Summarized below are the technical considerations utilized to make this determination:

- The radiation levels near the reactor core or areas near irradiated fuel or other irradiated objects are not impacted by RSGs.
- The radiation levels in the rest of the plant, both inside and outside containment, are primarily controlled by radiation sources that are derived from primary coolant activity. The change in primary coolant activity, and associated impact on radiation levels, due to the minor change in reactor coolant mass resulting from the RSGs, is expected to be minimal.

It is therefore concluded that RSGs have negligible impact on normal operation radiation levels at the plant, shielding adequacy, and the normal operation component of the radiation environment used for equipment qualification.

5.11.6 Normal Operation Annual Radwaste Effluent Releases

Liquid and gaseous effluents released to the environment during normal plant operations contain small quantities of radioactive materials. RSGs will have negligible impact on normal operation radioactive effluents. Summarized below are the technical considerations utilized to make this determination:

- The operation/availability of plant liquid and gaseous radioactive systems will remain unchanged following RSG installation.
- The current radioactive waste system operating procedures and philosophy will remain unchanged following RSG installation.
- The liquid and gaseous volumetric inputs into the radwaste systems would be minimally affected by the RSG installation.
- The radwaste effluent releases are primarily controlled by reactor coolant activity. The change in reactor coolant activity, and associated impact on radioactive effluents, due to the minor change in reactor coolant mass resulting from the RSGs, is expected to be minimal.

It is therefore concluded that RSGs have negligible impact on normal operation radioactive effluents.

5.11.7 Radiological Environmental Doses for Equipment Qualification

In accordance with 10CFR50.49 safety-related electrical equipment must be qualified to survive the radiation environment at their specific location during normal operation and during an accident. (Reference 18)

For the purposes of equipment qualification (EQ), BVPS-1 is divided into various environmental zones. The radiological environmental conditions noted for these zones are the maximum conditions expected to occur and are representative of the whole zone. Normal operation values represent 40 years of operation. The post-accident radiation levels are based on the LOCA and TID 14844 source terms with an accident duration of six months.

RSGs will have negligible impact on the radiological environmental dose used for equipment qualification. Summarized below are the technical considerations utilized to make this determination.

- As noted in Section 5.11.5, RSGs have negligible impact on the normal operation component of the radiation environment used for equipment qualification.
- RSGs will not affect the radiation environments following a LOCA.

It is therefore concluded that RSGs have negligible impact on the radiation environments utilized for equipment qualification.

5.11.8 Post-LOCA Access to Vital Areas

In accordance with NUREG 0737, II.B.2, vital areas are those areas within the station that will or may require access/occupancy to support accident mitigation or recovery following a LOCA (Reference 13). The NRC SER issued to BVPS-1 relative to compliance with NUREG 0737 II.B.2 is documented in Reference 12.

RSGs will have no affect on the radiation environments following a LOCA. It is therefore concluded that RSGs have no affect on operator exposure while performing vital missions to support accident mitigation or recovery following a LOCA.

5.11.9 Post-Accident Site Boundary and Control Room Doses

5.11.9.1 Introduction

As discussed in Sections 5.11.1 and 5.11.2, as holder of operating licenses issued prior to January 10, 1997, and in accordance with 10 CFR 50.67 and Standard Review Plan 15.0.1, BVPS proposes to revise the accident source terms used in the BVPS-1 design basis site boundary and control room dose analyses to extend the selective implementation of Alternative Source Terms (AST) as detailed in Regulatory Guide 1.183 to all accidents affected by the RSGs.

The impact of the RSGs on the site boundary and control room doses are discussed for the following accidents applicable to BVPS licensing basis:

1. Loss of Coolant Accident (LOCA) (NA, EPU only)
2. Control Rod Ejection Accident (CREA)
3. Main Steam Line Break (MSLB) outside Containment
4. Steam Generator Tube Rupture (SGTR)
5. Locked Rotor Accident (LRA)
6. Loss of AC Power (LACP)
7. Fuel Handling Accident (FHA) in the Fuel Pool or in Containment (NA, EPU only)
8. Small Line Break (SLB) Outside Containment
9. Waste Gas System Rupture (WGSR) (NA, EPU only)

Note that the CREA is addressed in this application by reference only, since the accident analyses was performed assuming RSGs and EPU conditions and was approved by License Amendment No. 257. The Loss of Coolant Accident (LOCA) and the Fuel Handling Accident (FHA) are not impacted by the RSGs. The impact of RSGs on the Waste Gas System Rupture (WGSR) is deemed negligible based on current licensing basis. The change in primary coolant mass due to the RSGs have minimal impact on the current design primary coolant source terms; consequently, the RSGs will have negligible impact on the dose consequences at the site boundary and control room following a WGSR.

At BVPS, the SLB Outside Containment, LACP, MSLB and SGTR are not directly impacted by the implementation of the AST as there is no accident initiated fuel damage associated with these events. However, with this expanded selective implementation of AST at BVPS-1, the dose acceptance criteria of 10 CFR 50.67 become applicable to all of the accidents listed in Regulatory Guide 1.183 affected by the RSG implementation, which include the MSLB and the SGTR. It is noted that the SLB Outside Containment and the LACP are not addressed in Regulatory Guide 1.183. The dose criteria to which they are evaluated are discussed in Section 5.11.2.

The worst 2-hour period dose at the EAB, and the dose at the LPZ for the duration of the release are calculated for each of the design basis accidents based on postulated airborne radioactivity releases. This represents the post-accident dose to the public due to inhalation and submersion for each of these events. In accordance with Reference 3, offsite breathing rates used are as follows: 0-8 hr (3.5E-04 m^3/sec), 8-24 hr (1.8E-04 m^3/sec), 1-30 days (2.3E-04 m^3/sec). Due to distance/plant shielding, the dose contribution at the EAB/LPZ due to direct shine from contained sources is considered negligible for all the accidents.

The 0 to 30-day dose to an operator in the control room due to airborne radioactivity releases is developed for each of the design basis accidents. This represents the post-accident dose to the operator due to inhalation and submersion. The CR shielding design is based on the LOCA, which represents the worst case DBA relative to radioactivity releases. The direct shine dose due to contained sources/external cloud is included in the CR doses reported for the LOCA.

The updated site boundary and control room dose analyses reflect EPU conditions, AST (as applicable), and except as noted, bounding parameter values to encompass an event at either unit. In addition the parameter values assigned to the BVPS-1 steam generators reflect the Replacement Steam Generators. The analysis reflects a SG tube leakage rate of 150 gpd/SG. The MSLB and the SGTR dose analyses are unit specific. ARC is not utilized in the BVPS-1 MSLB dose analysis because it is not applicable to the Model 54F Replacement Steam Generators. The SGTR dose analyses for BVPS-1 reflect environmental releases based on the unit-specific licensing basis mass and energy release calculation methodology.

It is noted that the control room dose analyses reflect a control room design consistent with that approved by the NRC in its SER for OL Amendment No. 257. Specifically, the approved design changes include:

- Conservative estimates of control room unfiltered inleakage that envelope the results of recent tracer gas testing performed in the year 2001, and provide margin for potential surveillance tests.
- Revised Technical Specification acceptance criteria for the BVPS-1 control room HEPA and charcoal filters which make the BVPS-1 acceptance criteria similar to the more limiting criteria for the BVPS-2 control room filters.
- Elimination of taking credit for the automatic initiation feature of the safety related control room monitors to initiate the control room emergency pressurization system.
- Manual initiation of CREVS at T=30 minutes for those events that take credit for the control room emergency ventilation system.
- Updated control room atmospheric dispersion factors using ARCON96 methodology.

In addition, the BVPS-1 MSLB and SGTR take credit for a 30 minute control room purge after the accident sequence is complete and the environmental release has been terminated.

Except as noted, the accident analyses considers a Loss of Offsite Power (LOOP) at T=0 hours or immediately subsequent to the accident if determined by the accident progression (e.g., the SGTR). The impact of a LOOP "significantly later" on in the accident, (such as during the fuel release phase of a LOCA), is not addressed per NRC Information Notice 93-17 (Reference 25). IN 93-17 concludes that plant design should reflect all credible sequences of the LOCA/LOOP, but states that a sequence of a LOCA and an unrelated LOOP is of very low probability and is not a concern. Likewise, a LOOP is not taken into consideration when evaluating the dose consequences of accidents that, in themselves, cannot cause a reactor trip.

5.11.9.2 Accident Atmospheric Dispersion Factors

Site Boundary Atmospheric Dispersion Factors

The Exclusion Area Boundary (EAB) and Low Population Zone (LPZ) atmospheric dispersion factors (χ/Q) for BVPS-1 and BVPS-2 remain unchanged by this application and are consistent with current licensing basis. These values are also the same as utilized for the LOCA and the CREA in Reference 5 and are presented in Table 5.11.9-1. As discussed earlier, with the exception of the MSLB and the SGTR which have unit specific analysis, for the purposes of performing bounding analyses representative for both units, the BVPS-2 EAB χ/Q's will be utilized in assessing the impact of EPU on all of the remaining design basis accidents listed in Section 5.11.9.1. As noted in Table 5.11.9-1, the LPZ χ/Q's are the same for both units.

On-Site Atmospheric Dispersion Factors

The control room χ/Q values for the environmental release paths associated with the design basis accidents listed for each unit in Section 5.11.9.1, are calculated using the latest version of the "Atmospheric Relative Concentrations in Building Wakes" (ARCON96) methodology (Ramsdell, 1997, Reference 20).

The methodology utilized to develop these atmospheric dispersion factors is discussed in detail in Section 5.3.4.2 of Reference 5. All releases are conservatively treated as ground-level as there are no releases at this site that are high enough to escape the aerodynamic effects of the plant buildings (i.e., 2.5 times Containment Building height, U.S. NRC, 1982).

BVPS RSG Project On-Site Atmospheric Dispersion Factors

BVPS-1 and BVPS-2 release point and receptor configuration information, release mode, and meteorological sensor configuration information used as input to ARCON96 are provided in Tables 5.11.9-2C and 5.11.9-2D. The release points addressed in Tables 5.11.9-2C and 5.11.9-2D include the BVPS-1 Ventilation Vent, Main Steam Line Break, and Air Ejector (AEJ), and the BVPS-2 Ventilation Vent, respectively. The receptors are the BVPS-1 and BVPS-2 control room air intakes. Note that the same set of X/Q values is utilized for the BVPS-1 MSLB Break Point and Air Ejector releases as they are conservatively assumed to both occur from the closest point of the turbine building to the control room air

intakes. Tables 5.11.9-2C and 5.11.9-2D do not include release point and receptor information for the Main Steam Relief Valve release points as the X/Qs associated with these release points have already been approved by the NRC in its SER for Amendment No. 257 (Reference 38).

A drawing showing the Site Postulated Release and Receptor Points on a plot plan of BVPS-1 and BVPS-2 (Drawing No. 8700-RY-1C, Rev. 1) was previously provided to the NRC via FENOC Letter L-03-007, January 30, 2003, in response to NRC Request for Additional Information (RAI) in support of LAR 300/172 (Reference 5). A floppy disk containing the 1990-1994 BVPS on-site meteorological data input to ARCON96, in the ARCON96 input data format, was also provided in the referenced RAI response.

As noted in Reference 5, the control room air intake χ/Q values are representative of the worst case χ/Q values for control room unfiltered in-leakage since the distances and directions from the release points to these receptors are very similar.

- Control room tracer gas tests have indicated that potential sources of unfiltered inleakage into the control room during the post-accident pressurization mode are the normal operation dampers associated with the control room ventilation system. The same χ/Q as that of the Control Room air intake are assigned to this location.

- The other source of inleakage is potentially that associated with ingress/egress and leakage via door seals. This inleakage is assigned to the door leading into the control room that is considered the point of primary access. This door is located in-between the BVPS-1 and BVPS-2 control room air intakes and is located close enough to the air intakes to allow the χ/Q associated with the air intakes to be assigned to this source of inleakage.

The BVPS-1 and 2 χ/Q values for all release-receptor combinations utilized for the design basis accidents discussed in Section 5.11.9.1 are summarized in Tables 5.11.9-2a and 5.11.9-2b, respectively.

5.11.9.3 Dose Calculation Methodology

The dose calculation methodology is similar to that outlined in Section 5.3.5 of Reference 5. As noted in Reference 5, computer program PERC2 is used to calculate the Committed Effective Dose Equivalent (CEDE) from inhalation and the Deep Dose Equivalent (DDE) from submersion due to halogens, noble gases and other nuclides at the offsite locations and in the control room. The CEDE is calculated using the Federal Guidance Report No.11, Sept. 1988 (Reference 21) dose conversion factors. The committed doses to other organs due to inhalation of halogens, noble gas, other nuclides and their daughters are also calculated. PERC2 is a multiple compartment activity transport code with the dose model consistent with the regulatory guidance. The decay and daughter build-up during the activity transport among compartments and the various cleanup mechanisms are included.

The PERC2 activity transport model, first calculates the integrated activity (using a closed form integration solution) at the offsite locations and in the control room air region, and then calculates the cumulative doses as described below:

Committed Effective Dose Equivalent (CEDE) Inhalation Dose – The dose conversion factors by isotope are applied to the activity in the air space of the control room, or at the EAB/LPZ. The exposure is adjusted by the appropriate respiration rate and occupancy factors for the CR dose at each integration interval as follows:

$$Dh(j) = A(j) \times h(j) \times C2 \times C3 \times CB \times CO$$

Where:

Dh(j) = Committed Effective Dose Equivalent (rem) from isotope j

A(j) = Integrated Activity (Ci-s/m3)

h(j) = Isotope j Committed Effective Dose Equivalent (CEDE) dose conversion factor (mrem/pCi) based on Federal Guidance Report No. 11, Sept. 1988

C2 = Unit conversion of 1x1012 pCi/Ci

C3 = Unit conversion of 1x10-3 rem/mrem

CB = Breathing rate (m3/s)

CO = Occupancy factor

Deep Dose Equivalent (DDE) from External Exposure – According to the guidance provided in Section 4.1.4 and Section 4.2.7 of RG 1.183, the Effective Dose Equivalent (EDE) may be used in lieu of DDE in determining the contribution of external dose to the TEDE if the whole body is irradiated uniformly. The EDE in the control room is based on a finite cloud model that addresses buildup and attenuation in air. The dose equation is based on the assumption that the dose point is at the center of a hemisphere of the same volume as the control room. The dose rate at that point is calculated as the sum of typical differential shell elements at a radius R. The equation utilizes, the integrated activity in the control room air space, the photon energy release rates per energy group from activity airborne in the control room, and the ANSI/ANS 6.1.1-1991 "neutron and gamma-ray fluence-to-dose factors" (Reference 22).

The Deep Dose Equivalent at the EAB and LPZ locations is very conservatively calculated using the semi-infinite cloud model outlined in TID-24190, Section 7-5.2, Equation 7.36, (Reference 23) where 1 rad is assumed to be equivalent to 1 rem.

$$\gamma D\infty(x,y,0)\ \text{rad} = 0.25\ E\gamma_{BAR}\ \psi(x,y,0)$$

$E\gamma_{BAR}$	=	average gamma released per disintegration (Mev/dis)
$\psi(x,y,0)$	=	concentration time integral (Ci-sec/m3)
0.25	=	$[\ 1.11 \times 1.6\text{x}10^{-6} \times 3.7\text{x}10^{10}\ ] / [\ 1293 \times 100 \times 2\ ]$

where:

1.11	=	ratio of electron densities per gm of tissue to per gm of air
$1.6\text{x}10^{-6}$ (erg/Mev)	=	number of ergs per Mev
$3.7\text{x}10^{10}$ (dis/sec-Ci)	=	disintegration rate per curie
1293 (g/m3)	=	density of air at S.T.P.
100	=	ergs per gram per rad
2	=	factor for converting an infinite to a semi-infinite cloud

5.11.9.4 Control Room Design/Operation/Transport Model

BVPS is served by a single control room that supports both units. The joint control room is serviced by two ventilation intakes, one assigned to BVPS-1 and the other to BVPS-2. These air intakes serve both units and are utilized for both the normal as well as the accident mode.

The BVPS-2 Control Room Emergency Ventilation System (CREVS) system is safety-related, fully automated, and fully compliant with relevant regulatory requirements. In the unlikely event that neither of the BVPS-2 trains can be put in service, operator action may be utilized to initiate the BVPS-1 control room filtered emergency pressurization system. To ensure bounding values, the atmospheric dispersion factors utilized for the identified release paths per accident reflect the limiting control room intake for each time period.

During normal plant operation, both ventilation intakes are operable providing a total supply of 500 cfm of unfiltered outside air makeup which includes all potential inleakage and uncertainties.

For purposes of dose assessment, no credit is taken for automatic initiation of the control room emergency ventilation system following any design basis accident. For events that take credit for operation of the CREVS, the analyses assume manual initiation, and that a pressurized control room is available at T=30 minutes after the accident. For selected accidents, credit is taken for control room clean-up via a half-hour control room purge, at a purge flow rate of 16,200 cfm, after the environmental release due to the accident is terminated. Plant operating procedures will be revised as necessary to incorporate changes to analytical assumptions relative to maintenance of the control room atmosphere.

As discussed in Section 5.11.9.3, and Reference 5, and in accordance with the current licensing basis, the atmospheric dispersion factors associated with control room inleakage are considered to be the same as those utilized for the control room intake. The estimated inleakage envelopes the results of recent tracer gas testing performed in the year 2001, include 10 cfm for ingress/egress, and provide margin for potential deterioration between surveillance tests.

As noted in Reference 5, the control room emergency filtered ventilation intake flow varies between 600 to 1030 cfm, which includes allowance for measurement uncertainties. For reasons outlined below, the dose model uses the minimum intake flow rate of 600 cfm in the pressurized mode as it is more limiting. Although the filtered intake of radioisotopes is higher at the larger intake rate of 1030 cfm, it is small compared to the radioactivity entering the control room, in both cases, due to unfiltered inleakage. Consequently, the depletion of airborne activity in the control room via the higher outleakage rate of 1030 cfm make the lower intake rate of 600 cfm more limiting from a dose consequence perspective. This argument holds true because the CEDE from inhalation is far more limiting than the DDE from immersion which is principally from noble gases.

Table 5.11.9-3 lists key assumptions and input parameters associated with BVPS control room design utilized in Reference 5 and applicable to the RSG/EPU analyses.

5.11.9.5 Loss of Coolant Accident (LOCA) (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.11.9.6 Control Rod Ejection Accident (CREA)

The dose consequences at the site boundary and in the control room following a CREA is addressed in this application by reference only, since, the CREA analysis, approved by NRC in its SER for OL Amendment No. 257, was performed at EPU conditions with RSGs and utilized Alternative Source Terms. The methodology utilized to analyze the CREA is discussed in Section 5.3.6.4 of Reference 5.

The EAB, LPZ and Control Room dose following a CREA at EPU conditions are presented in Tables 5.11.9-11 and 5.11.9-12.

5.11.9.7 Main Steam Line Break (MSLB) Outside Containment

Computer program PERC2 is used to calculate the control room and site boundary doses due to airborne radioactivity releases following a MSLB at BVPS-1 at EPU conditions.

The BVPS-1 MSLB dose assessments follow the guidance provided in RG 1.183. Table 5.11.9-4a lists the key parameters utilized to develop the radiological consequences following the MSLB at BVPS-1.

The radiological model used for the MSLB assessment conservatively assumes immediate dry-out of the faulted SG following a MSLB resulting in the instantaneous release of all of the SG contents, which are assumed at maximum Technical Specification concentrations. Based on an assumption of a simultaneous Loss of Offsite Power, the condenser is unavailable, and environmental steam releases via the MSSVs/ADVs from the intact steam generators are used to cool down the reactor until the Residual Heat Removal (RHR) system starts shutdown cooling. The elevated iodine activity in the RCS due to a postulated pre-accident or concurrent iodine spike, as well as the noble gas (at Technical Specification concentrations), leak into the faulted and intact steam generators, and are released to the environment from the break point, and from the MSSVs/ADVs, respectively.

The steam releases from the intact SGs continue until shutdown cooling is initiated via operation of the RHR system at T= 8 hrs, resulting in the termination of environmental releases via this pathway. The releases from the faulted SG due to primary to secondary leakage continues until T=19 hrs (i.e., estimated time for the RHR System to bring the primary coolant temperature down to 212°F).

Since there is no postulated fuel damage associated with this accident, the primary radiation source is the activity in the reactor coolant system. Two iodine spiking cases are addressed: a pre-accident iodine spike and a concurrent iodine spike. The analysis conservatively uses the proposed (EPU LAR 302/173) BVPS-1 Technical Specification limits for the primary and secondary coolant activity.

a. Pre-accident spike – initial primary coolant iodine activity is assumed to be at 21 μCi/gm of DE I-131, (proposed Technical Specification transient limit for full power operation). Initial primary coolant noble gas activity is conservatively assumed to be at the proposed Technical Specification levels.

b. Concurrent spike – the initial primary coolant iodine activity is assumed to be at 0.35 μCi/gm DE I-131 (proposed equilibrium Technical Specification limit for full power operation). Immediately following the accident the iodine appearance rate from the fuel to the primary coolant is assumed to increase to 500 times the equilibrium appearance rate corresponding to the 0.35 μCi/gm DE I-131 coolant concentration. In accordance with the current design basis, the duration of the assumed spike is four hours. The initial primary coolant noble gas activity is assumed to be at the proposed Technical Specification levels.

The initial secondary coolant iodine activity is assumed to be at the proposed (EPU LAR 302/173) Technical Specification limit of 0.1 μCi/gm DE I-131.

Following a MSLB, the primary and secondary reactor coolant activity is released to the environment via two pathways; i.e., the MSLB location and the MSSVs/ADVs. The most limiting atmospheric dispersion factors for each of the release points relative to the two CR intakes (identified for purposes of assessment as the BVPS-1 MSSVs/ADVs to the BVPS-1 CR intake, and the BVPS-1 MSLB location to the BVPS-1 Intake) are selected to determine a bounding control room dose.

Faulted Steam Generator

The release from the faulted Steam Generator occurs via the postulated break point of the main steam line. The faulted steam generator is conservatively assumed to dry-out instantaneously following the MSLB, releasing all of the iodines in the secondary coolant that was initially contained in the steam generator. The secondary steam initially contained in the faulted steam generator is also released; however, this contribution is not included in this analysis since the associated radioactivity is insignificant compared to the other contributions. The primary to secondary leakage reflects 150 gpd at STP. All iodine and noble gas activities in the referenced tube leakage are released directly to the environment without hold-up or decontamination.

Intact Steam Generator

The release from the two remaining intact steam generators (used to cool the reactor and the primary system) occur via the plant MSSVs/ADVs. The iodine activity in the intact SG liquid is released to the environment in proportion to the steaming rate and the partition factor. The steam releases from the MSSVs/ADVs terminate at 8 hours after the event when shutdown cooling is initiated via the RHR System.

EAB 2 hr Worst Case Window

AST methodology requires that the worst case dose to an individual located at any point on the boundary at the EAB, for any 2-hr period following the onset of the accident be reported as the EAB dose:

- The Source/Release for the Pre-incident Spike Case is at its maximum levels between 0 and 2 hours.
- The Source/Release for the Concurrent Spike Case is at its maximum levels between 4 (end of the spiking period) and 6 hours.

Regardless of the starting point of the "Worst 2-hr Window," the 0-2 hrs X/Q is utilized.

Accident Specific Control Room Model Assumptions

The control room emergency ventilation system is manually initiated and a pressurized control room is available at T=30 mins after the accident. Following termination of the environmental release, the control room is purged, at T=24 hrs, at a rate of 16,200 cfm, for a period of 30 mins. The remaining CR parameters utilized in this model are discussed in Section 5.11.9.4.

The EAB, LPZ and Control Room dose following a MSLB at EPU conditions are presented in Tables 5.11.9-11 and 5.11.9-12.

5.11.9.8 Steam Generator Tube Rupture (SGTR)

Computer program PERC2 is used to calculate the control room and site boundary doses due to airborne radioactivity releases following a SGTR at BVPS-1 at EPU conditions.

The dose assessments follow the guidance provided in Regulatory Guide 1.183. Table 5.11.9-5a lists the key parameters utilized to develop the radiological consequences following a SGTR at BVPS-1.

The SGTR results in a reactor trip and a simultaneous loss of offsite power at 225 seconds after the event. Due to the tube rupture the primary coolant with elevated iodine concentrations (pre-accident or concurrent iodine spike) flows into the faulted steam generator and the associated activities are released to the environment via secondary side steam releases. Before the reactor trip, the activities are released from the air ejector. After the reactor trip the steam release is via the MSSVs/ADVs. The spiking primary coolant activities leaked into the intact steam generator at the maximum allowable primary-to-secondary leakage value are also released to the environment via secondary steam releases. The most limiting

atmospheric dispersion factors for each of the release points relative to the two CR intakes (identified for purposes of assessment as the BVPS-1 MSSVs/ADVs to the BVPS-1 CR intake, and the BVPS-1 Air Ejector to the BVPS-1 Intake) are selected to determine a bounding control room dose.

Since there is no postulated fuel damage associated with this accident, the main radiation source is the activity in the primary coolant system. Two spiking cases are addressed: a pre-accident iodine spike and a concurrent iodine spike. The analysis conservatively uses the Technical Specification limits for the RCS and secondary coolant proposed in EPU LAR 302/173.

a. Pre-accident spike – the initial primary coolant iodine activity is assumed to be 21 μCi/gm of DE I-131 (proposed BVPS-1 transient Technical Specification limit for full power operation). The initial primary coolant noble gas activity is assumed to be at the Technical Specification levels proposed in EPU LAR 302/173.

b. Concurrent spike – the initial primary coolant iodine activity is assumed to be 0.35 μCi/gm DE I-131 (equilibrium Technical Specification limit for full power operation proposed in EPU LAR 302/173). Immediately following the accident, the iodine appearance rate from the fuel to the primary coolant is assumed to increase to 335 times the equilibrium appearance rate corresponding to the 0.35 μCi/gm DE I-131 coolant concentration. In accordance with the current design basis, the duration of the assumed spike is 4 hours. The initial primary coolant noble gas activity is assumed to be at the Technical Specification levels proposed in EPU LAR 302/173.

The initial secondary side liquid and steam activity is relatively small and its contribution to the total dose is small compared to that contributed by the rupture flow. However, the release of the secondary side liquid activity and the resultant doses are also included in this analysis. The initial secondary side iodine activity is assumed to be at the proposed (EPU LAR 302/173) Technical Specification limit of 0.1 μCi/gm DE I-131.

Faulted SG Release

A postulated SGTR will result in a large amount of primary coolant being released into the faulted steam generator via the break location with a significant portion of it flashed to the steam space. The noble gases in the break flow and the iodine in the flashed flow are assumed immediately available for release from the steam generator without retention. The iodine in the non-flashed portion of the break flow mixes uniformly with the steam generator liquid mass and is released into the steam space in proportion to the steaming rate and partition factor. Before the reactor trip at 225 seconds, the activities in the steam are released to the environment from the main condenser air ejector. All steam noble gases and organic iodine are released directly to the environment. Only a portion of the elemental iodine carried with the steam is partitioned to the air ejector and released to the environment. The rest is partitioned to the condensate, returned to all three steam generators and assumed to be available for future steaming release. After the reactor trip, the break flow continues until the primary system is fully depressurized. No credit is taken for the condenser, since, a LOOP is assumed to occur simultaneously with the reactor trip. The steam is released from the MSSVs/ADVs. All activity releases from the faulted steam generator cease when it is isolated at 30 minutes after the accident.

Intact SG release

The activity release from the intact steam generator is due to normal primary-to-secondary leakage and steam release from the secondary side. The Primary-to-Secondary leak rate is assumed to be 150 gpd per SG. All of the iodine activity in the referenced leakage is assumed to mix uniformly with the steam generator liquid and released in proportion to the steaming rate and the partition factor. Before the reactor trip at 225 seconds, the steam is released from the main condenser air ejector. After the reactor trip, the steam is released from the MSSVs/ADVs. The reactor coolant noble gases that enter the intact steam generator are released directly to the environment without holdup. The steam release from the intact steam generator continues until initiation of shutdown cooling 8 hours after the accident.

Release of Initial SG Liquid Activity

The initial iodine inventory in the steam generator liquid is assumed to be at Technical Specification levels and is released to the environment, due to steam releases, via the condenser/air ejector before reactor trip, and via the MSSVs/ADVs after reactor trip. The release from the faulted SG stops at T=30 mins. The release from the intact SGs continue until 8 hrs after the accident.

EAB 2 hr Worst Case Window

AST methodology requires that the worst case dose to an individual located at any point on the boundary at the EAB, for any 2-hr period following the onset of the accident be reported as the EAB dose. The major source for the SGTR is the flashed portion of the RCS break flow which is terminated when the faulted SG is isolated. Therefore the worst 2-hr window dose for both the pre-accident and accident initiated spike case occurs during T=0 hr to T=2 hrs after the accident.

Accident Specific Control Room Model Assumptions

No credit is taken for initiation of the control room emergency ventilation system following a SGTR. Following termination of the environmental release, the control room is purged, at T=8 hrs, at a rate of 16,200 cfm, for a period of 30 mins. The remaining CR parameters utilized in this model are discussed in Section 5.11.9.4.

The EAB, LPZ and Control Room dose following a SGTR at EPU conditions are presented in Tables 5.11.9-11 and 5.11.9-12.

5.11.9.9 Locked Rotor (LR) and Loss of AC Power (LACP)

Computer program PERC2 is used to calculate the control room and site boundary doses due to airborne radioactivity releases following a LR accident at BVPS-1 or BVPS-2 at EPU conditions. As noted in Section 5.11.1, bounding parameter values are used to encompass an event at either unit.

The dose assessment follows the guidance provided in Regulatory Guide 1.183. Table 5.11.9-6 lists the key assumptions and parameters utilized to develop the radiological consequences following a BVPS LR accident. Table 5.11.9-7 lists the key parameters associated with a BVPS LACP. The transport models associated with the two events are similar with the exception that the LR event results in fuel

damage and associated release of gap activity, whereas the LACP has no fuel damage, and the maximum release is associated with Technical Specification concentrations. Since the RCS Technical Specification activity is significantly smaller than the gap activity associated with failed fuel, it is concluded that the dose consequences of the LR bound that of the LACP.

A BVPS LR accident results in less than 20% failed fuel and a release of the associated gap activity. The gap activity (consisting of noble gases, halogens and alkali metals) are instantaneously and homogeneously mixed in the reactor coolant system and transmitted to the secondary side via primary to secondary steam generator tube leakage assumed to be at the value of 450 gpd @STP.

A radial peaking factor of 1.75 is applied to the activity release. The chemical form of the iodines in the gap are assumed to be 95% CsI, 4.85% elemental and 0.15% organic. At BVPS, the SG tubes remain submerged for the duration of the event; therefore, the gap iodines are assumed to have a partition coefficient of 100 in the SG. The iodine releases from the SG are assumed to be 97% elemental and 3% organic. The gap noble gases are assumed to be released freely to the environment without retention in the SG, whereas the particulates are carried over in accordance with the design basis SG moisture carryover fraction.

The condenser is assumed unavailable due to a coincident loss of offsite power. Consequently, the radioactivity release resulting from a LR is discharged to the environment from the steam generators via the MSSVs and the ADVs. The SG releases continue for 8 hours, at which time shutdown cooling is initiated via operation of the RHR system, and environmental releases are terminated.

The activity associated with the release of secondary steam and liquid, and primary to secondary leakage of normal operation RCS, (both at Technical Specification activity limits) via the MSSVs/ADVs is insignificant compared to the failed fuel release, and are therefore not included in this assessment.

The most limiting atmospheric dispersion factors between the MSSVs/ADVs at each unit relative to the two CR intakes (identified for purposes of assessment as the BVPS-1 MSSVs/ADVs to the BVPS-1 CR intake) is selected to determine a bounding control room dose.

EAB 2-Hour Worst Case Window

AST methodology requires that the worst case dose to an individual located at any point on the boundary at the EAB, for any 2-hr period following the onset of the accident be reported as the EAB dose. For the LR event, the worst two hour period can occur either during the 0-2 hr period when the noble gas release rate is the highest, or during the 6-8 hr period when the iodine and particulate level in the SG liquid peaks (SG releases are terminated at T=8 hrs). Regardless of the starting point of the worst 2 hr window, the 0-2 hr EAB X/Q is utilized.

Accident Specific Control Room Model Assumptions

The control room is conservatively assumed to remain in the normal operation mode. The remaining CR parameters utilized in this model are discussed in Section 5.11.9.4.

The EAB, LPZ and Control Room dose following a LR event at EPU conditions are presented in Tables 5.11.9-11 and 5.11.9-12.

5.11.9.10 Fuel Handling Accident (FHA) in the Fuel Pool or in the Containment (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.11.9.11 Small Line Break (SLB) Outside Containment

Computer program PERC2 is used to calculate the control room and site boundary doses due to airborne radioactivity releases following a SLB outside Containment at BVPS-1 or BVPS-2 at EPU conditions. As noted in Section 5.11.1, bounding parameter values are used to encompass an event at either unit.

Regulatory Guide 1.183 does not address a SLB outside Containment. The dose assessment herein follows the current BVPS licensing basis model, but for purposes of consistency, uses the most limiting dose limits set by Regulatory Guide 1.183 for accident evaluations. Table 5.11.9-9 lists the key assumptions and parameters utilized to develop the radiological consequences following a SLB outside Containment at BVPS.

The SLB outside containment postulates the break of the 2 inch RCS letdown line in the Auxiliary Building resulting in a maximum break flow of 16.79 lbm/sec. Thirty seven percent of the break flow is calculated to flash. The iodine activity in the break flow is assumed to become airborne in proportion to the flash fraction, whereas the noble gases are assumed to be airborne and discharged to the environment without decontamination or holdup.

Since there is no postulated fuel damage associated with this accident, the main radiation source is the activity in the primary coolant system. In accordance with current licensing basis and SRP 15.6.2 (Reference 37), a concurrent iodine spike is included in the source term.

The initial primary coolant iodine activity is assumed to be 0.35 μCi/gm DE I-131 (current equilibrium BVPS-2 and conservatively assumed equilibrium BVPS-1 Technical Specification limit for full power operation). Immediately following the accident, the iodine appearance rate from the fuel to the primary coolant is assumed to increase to 500 times the equilibrium appearance rate corresponding to the 0.35 μCi/gm DE I-131 coolant concentration. In accordance with the current design basis, the duration of the assumed spike is 4 hours. The iodine released from the RCS is assumed to be 97% elemental and 3% organic.

The activity in the Auxiliary Building is released to the environment via the Ventilation Vent. The most limiting atmospheric dispersion factors between the ventilation vent release point at each unit relative to the two CR intakes (identified for purposes of assessment as the BVPS-1 Ventilation Vent to the BVPS-1 CR intake) is selected to determine a bounding control room dose. No credit is taken for Auxiliary building holdup or filtration. The break flow is isolated by manual operator action after a period of 15 minutes.

EAB 2 hr Worst Case Window

AST methodology requires that the worst case dose to an individual located at any point on the boundary at the EAB, for any 2-hr period following the onset of the accident be reported as the EAB dose. Since the event is based on a 15 minute release, the worst 2-hour period for the EAB is the 0 to 2-hour period.

Accident Specific Control Room Model Assumptions

The control room is assumed to remain in the normal operation mode. The remaining CR parameters utilized in this model are discussed in Section 5.11.9.4.

The EAB, LPZ and Control Room dose following a SLB outside Containment at EPU conditions are presented in Tables 5.11.9-11 and 5.11.9-12.

5.11.9.12 Waste Gas System Rupture (WGSR) (EPU Section)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

5.11.10 Conclusions

The radiological analyses and evaluations documented in this section demonstrate that RSG implementation will not impact compliance with applicable regulatory radiological dose limits for normal operation and for accidents.

The radiological impact of RSG has been evaluated for the following:

- Normal Operation Dose Rates and Shielding
- Normal Operation Annual Radwaste Effluent Releases
- Radiological Environmental Doses for Equipment Qualification (EQ)
- Post-LOCA Access to Vital Areas
- Post-Accident Site Boundary and Control Room Doses

The regulatory acceptance criteria being utilized in the RSG assessments are discussed in Section 5.11.2. It is noted that as part of the RSG application, the accident source term used for the BVPS-1 design basis site boundary and control room dose analyses affected by RSGs reflect EPU conditions and selective implementation of Alternative Source Terms (AST) as provided in 10 CFR 50.67 and Regulatory Guide 1.183.

The conclusions of the RSG evaluation are summarized below.

5.11.10.1 Normal Operation Dose Rates and Shielding

RSGs will have negligible impact on normal operation radiation levels at the plant, shielding adequacy, and the normal operation component of the radiation environment used for equipment qualification.

5.11.10.2 Normal Operation Annual Radwaste Effluent Releases

RSGs will have negligible impact on normal operation radioactive effluents.

5.11.10.3 Radiological Environmental Doses for Equipment Qualification (EQ)

RSGs will have negligible impact on the radiation environments utilized for equipment qualification.

5.11.10.4 Post-LOCA Access to Vital Areas

RSGs will have no affect on operator exposure while performing vital missions to support accident mitigation or recovery following a LOCA.

5.11.10.5 Post-Accident Site Boundary and Control Room Doses

In support of RSG implementation, the dose consequences at the site boundary and the control room, for the design accidents applicable to the BVPS licensing basis and impacted by RSGs have been re-analyzed to expand the selective implementation of Alternative Source Terms (AST) as detailed in Regulatory Guide 1.183 to include all accidents affected by the RSGs (MSLB, SGTR, LRA, LACP, SLB and CREA). Note that the CREA is addressed in this application by reference only, since, the referenced accident analysis, approved by the NRC in SER for OL Amendment No. 257, was performed at EPU conditions with RSGs.

It is noted that the control room dose analyses reflect a control room design consistent with that approved by the NRC in its SER for OL Amendment No. 257.

In addition, the BVPS-1 MSLB and SGTR take credit for a 30 minute control room purge after the accident sequence is complete and the environmental release has been terminated.

It is concluded that following RSG implementation the dose consequences at the site boundary and control room following all design basis accidents impacted by the RSGs will remain within the regulatory requirements of 10 CFR 50.67.

5.11.11 References

1. 10 CFR 50.67, "Accident Source Term."

2. NUREG-0800, Standard Review Plan 15.0.1, "Radiological Consequence Analyses using Alternative Source Terms," Revision 0.

3. Regulatory Guide 1.183, Revision 0, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," July 2000.

4. NRC Safety Evaluation Report enclosing Amendment No. 241 (BVPS-1) and No. 121 (BVPS-2), "Beaver Valley Power Station Units 1&2 – Issuance of Amendment Re: Revised Fuel Handling Accident Safety Analysis and Requirements for Handling Irradiated Fuel Assemblies in the Reactor Containment and in the Fuel Building."

5. Beaver Valley Power Station Units 1 and 2 Licensing Amendment Request (LAR) No's 300 and 172, L-02-069 entitled "Containment Conversion" June 5, 2002.

6. Regulatory Guide 1.49, "Power Levels of Nuclear Power Plants," Revision 1.

7. U.S. Nuclear Regulatory Commission: Amendment No. 243/122 to Facility Operating Licenses No. DPR-66 and NPF-73, Beaver Valley Power Station, BVPS-1 and 2; "1.4 Percent Power Uprate" (TAC No. MB0996, MB0997, and MB2557); Sept. 24, 2001.

8. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

9. TID 14844, "Calculation of Distance Factors for Power and Test Reactor Sites," 1962.

10. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

11. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

12. Safety Evaluation Report, "NUREG-0737, Item II.B.2 – Design Review of Plant Shielding – Corrective Actions for Access to Vital Areas, Beaver Valley Power Station Unit No. 1," date November 8, 1982.

13. NUREG-0737, "Clarification of TMI Action Plan Requirements," Nov. 1980.

14. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

15. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

16. Code of Federal Regulations, Title 10, Part 20, "Standards for Protection Against Radiation."

17. Code of Federal Regulations, Title 10, Part 50, Appendix I, "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low As Reasonably Achievable" for Radioactive Material in Light Water Cooled Nuclear Power Reactor Effluents."

18. Code of Federal Regulations, Title 10, Part 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants."

19. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

20. Ramsdell, J. V. Jr. and C. A. Simonen, "Atmospheric Relative Concentrations in Building Wakes." Prepared by Pacific Northwest Laboratory for the U.S. Nuclear Regulatory Commission, PNL-10521, NUREG/CR-6331, Rev. 1, May 1997.

21. EPA-520/1-88-020, September 1988, Federal Guidance Report No.11, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion and Ingestion."

22. ANSI/ANS 6.1.1-1991, "Neutron and Gamma-ray Fluence-to-Dose Factors."

23. TID-24190, Air Resources Laboratories, "Meteorology and Atomic Energy," July 1968.

24. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

25. NRC Information Notice 93-17, Revision 1, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," March 25, 1994 (original issue March 8, 1993).

26. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

27. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

28. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

29. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

30. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

31. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

32. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

33. Not used.

34. Not used.

35. Not used.

36. EPA 402-R-93-081, Federal Guidance Report No. 12, "External Exposure to Radio-nuclides in Air, Water and Soil, September, 1993.

37. NUREG-0800, Standard Review Plan 15.6.2, Revision 2, "Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment."

38. NRC Safety Evaluation Report Enclosing Amendment No. 257 (BVPS-1) and No. 139 (BVPS-2), "Beaver Valley Power Station Units 1 & 2 – Issuance of Amendments Re: Selective Implementation of Alternate Source Terms and Control Room Habitability Technical Specification Changes," September 10, 2003.

39. FENOC Letter L-03-135 to NRC dated September 5, 2003, "Withdrawal of the Containment Conversion Portion (Phase 2) of License Amendment Request Nos. 300 and 172."

40. (EPU Reference – This reference number is included to maintain numbering consistency with the EPU Licensing Report. This reference is not applicable for the RSG Licensing Report.)

Table 5.11.4-1
Assumed BVPS-1 and Current BVPS-2 Primary and Secondary Coolant Technical Specification Iodine and Noble Gas Activity Concentrations based on RSGs and EPU

Nuclide	Primary Coolant (µCi/gm)	Secondary Coolant (µCi/gm)
I-131	2.74E-01	8.33E-02
I-132	1.08E-01	1.40E-02
I-133	4.10E-01	9.39E-02
I-134	6.00E-02	1.95E-03
I-135	2.36E-01	3.39E-02
Kr-83m	3.89E-02	--
Kr-85m	1.35E-01	--
Kr-85	1.18E+01	--
Kr-87	9.00E-02	--
Kr-88	2.52E-01	--
Xe-131m	4.84E-01	--
Xe-133m	3.99E-01	--
Xe-133	2.95E+01	--
Xe-135m	9.09E-02	--
Xe-135	9.16E-01	--

Table 5.11.4-2
Assumed BVPS-1 and Current BVPS-2 Primary Coolant Pre-Accident Iodine Spike Activity Concentrations and Equilibrium Iodine Appearance Rates based on RSGs and EPU

Nuclide	Pre-Accident Iodine Spike Activity Concen. (µCi/gm)	Activity Appearance Rates (µCi/sec)
I-131	16.4	2.53E+03
I-132	6.5	2.66E+03
I-133	24.6	4.42E+03
I-134	3.6	3.00E+03
I-135	14.1	3.41E+03

Table 5.11.4-3
BVPS EPU Core Inventory of Dose Significant Isotopes in the Gap (2918 MWt)

Noble Gases		Halogens		Alkali Metals & BA137M	
Nuclide	Core Activity (Ci)	Nuclide	Core Activity (Ci)	Nuclide	Core Activity (Ci)
Kr-83M	9.46E+06	Br-82	3.02E+05	Rb-86	1.69E+05
Kr-85	8.27E+05	Br-83	9.37E+06	Rb-88	5.57E+07
Kr-85M	1.95E+07	Br-85	1.95E+07	Rb-89	7.26E+07
Kr-87	3.91E+07	–	–	Rb-90	6.69E+07
Kr-88	5.43E+07	–	–	Rb-90M	2.11E+07
Kr-89	6.75E+07	–	–	–	–
Kr-90	7.24E+07	I-129	2.86E+00	Cs-134	1.57E+07
		I-130	2.07E+06	Cs-134M	3.69E+06
Xe-131M	1.08E+06	I-131	7.78E+07	Cs-135M	4.39E+06
Xe-133	1.60E+08	I-132	1.14E+08	Cs-136	4.97E+06
Xe-133M	5.05E+06	I-133	1.60E+08	Cs-137	9.81E+06
Xe-135	4.84E+07	I-134	1.77E+08	Cs-138	1.48E+08
Xe-135M	3.36E+07	I-135	1.52E+08	Cs-139	1.37E+08
Xe-137	1.46E+08	I-136	6.99E+07	Cs-140	1.23E+08
Xe-138	1.36E+08	–	–	Ba-137M	9.35E+06

Table 5.11.8-1
BVPS-2 Post Accident Vital Access Doses (2918 MWt) (EPU Table)

(This table number is included to maintain numbering consistency with the EPU Licensing Report. The information in this table is not applicable for the RSG Licensing Report.)

Table 5.11.9-1 BVPS Site Boundary Atmospheric Dispersion Factors (sec/m^3)				
Exclusion Area Boundary Averaging Period				
Release Point	**0-2 hr**	–	–	–
BVPS-1 Release Points	1.04E-3	–	–	–
BVPS-2 Release Points	1.25E-3	–	–	–
Low Population Zone Averaging Period				
Release Point	**0-8 hr**	**8-24 hr**	**1-4 day**	**4-30 day**
BVPS-1 and BVPS-2 Release Points	6.04E-5	4.33E-5	2.10E-5	7.44E-6

Table 5.11.9-2A
BVPS-1 On-Site Atmospheric Dispersion Factors (sec/m^3)

Release	Receptor	0-2 hr	2-8 hr	8-24 hr	1-4 d	4-30 d
U 1 Containment Edge	BVPS-1 CR Intake	NA	NA	NA	NA	NA
U 1 Containment Top	BVPS-1 CR Intake	NA	NA	NA	NA	NA
U 1 Ventilation Vent	BVPS-1 CR Intake	4.75E-03	3.66E-03	1.43E-03	1.02E-03	8.84E-04
U 1 RWST Vent	BVPS-1 CR Intake	NA	NA	NA	NA	NA
U 1 MS Relief Valves	BVPS-1 CR Intake	1.24E-03	9.94E-04	4.08E-04	3.03E-04	2.51E-04
U 1 MSL (break)/AEJ	BVPS-1 CR Intake	1.05E-02	7.72E-03	3.01E-03	2.14E-03	2.00E-03
U 1 Gaseous Waste Storage Vault	BVPS-1 CR Intake	NA	NA	NA	NA	NA
U 1 Containment Equipment Hatch	BVPS-1 CR Intake	NA	NA	NA	NA	NA
U 1 Cooling Tower	BVPS-1 CR Intake	NA	NA	NA	NA	NA
U 1 Containment Edge	BVPS-2 CR Intake	NA	NA	NA	NA	NA
U 1 Containment Top	BVPS-2 CR Intake	NA	NA	NA	NA	NA
U 1 Ventilation Vent	BVPS-2 CR Intake	2.00E-03	1.62E-03	6.76E-04	5.05E-04	4.06E-04
U 1 RWST Vent	BVPS-2 CR Intake	NA	NA	NA	NA	NA
U 1 MS Relief Valves	BVPS-2 CR Intake	7.46E-04	6.31E-04	2.62E-04	1.98E-04	1.62E-04
U 1 MSL (break)/AEJ	BVPS-2 CR Intake	4.24E-03	3.87E-03	1.69E-03	1.18E-03	1.06E-03
U 1 Gaseous Waste Storage Vault	BVPS-2 CR Intake	NA	NA	NA	NA	NA
U 1 Containment Equipment Hatch	BVPS-2 CR Intake	NA	NA	NA	NA	NA
U 1 Cooling Tower	BVPS-2 CR Intake	NA	NA	NA	NA	NA
U 1 Containment Edge	BVPS-2 Aux. Bldg. NW Corner	NA	NA	NA	NA	NA
U 1 Containment Top	BVPS-2 Aux. Bldg. NW Corner	NA	NA	NA	NA	NA
U 1 RWST Vent	BVPS-2 Aux. Bldg. NW Corner	NA	NA	NA	NA	NA
U 1 Cooling Tower	BVPS-2 Aux. Bldg. NW Corner	NA	NA	NA	NA	NA
U 1 Containment Edge	BVPS-1 Service Bldg.	NA	NA	NA	NA	NA

Table 5.11.9-2A (continued)
BVPS-1 On-Site Atmospheric Dispersion Factors (sec/m^3)

Release	Receptor	0-2 hr	2-8 hr	8-24 hr	1-4 d	4-30 d
U 1 Containment Top	BVPS-1 Service Bldg.	NA	NA	NA	NA	NA
U 1 RWST Vent	BVPS-1 Service Bldg.	NA	NA	NA	NA	NA
U 1 Cooling Tower	BVPS-1 Service Bldg.	NA	NA	NA	NA	NA
U 1 Containment Edge	ERF Intake	NA	NA	NA	NA	NA
U 1 Containment Top	ERF Intake	NA	NA	NA	NA	NA
U 1 RWST Vent	ERF Intake	NA	NA	NA	NA	NA
U 1 Cooling Tower	ERF Intake	NA	NA	NA	NA	NA
U 1 Containment Edge	ERF Edge Closest to Cont.	NA	NA	NA	NA	NA
U 1 Containment Top	ERF Edge Closest to Cont.	NA	NA	NA	NA	NA
U 1 RWST Vent	ERF Edge Closest to Cont.	NA	NA	NA	NA	NA
U 1 Cooling Tower	ERF Edge Closest to Cont.	NA	NA	NA	NA	NA

Table 5.11.9-2B
BVPS-2 On-Site Atmospheric Dispersion Factors (sec/m^3)

Release	Receptor	0-2 hr	2-8 hr	8-24 hr	1-4 d	4-30 d
U 2 Contain. Edge	BVPS-1 CR Intake	NA	NA	NA	NA	NA
U 2 Containment Top	BVPS-1 CR Intake	NA	NA	NA	NA	NA
U 2 Ventilation Vent	BVPS-1 CR Intake	5.32E-04	3.89E-04	1.75E-04	1.30E-04	9.02E-05
U 2 RWST Vent	BVPS-1 CR Intake	NA	NA	NA	NA	NA
U 2 MS Relief Valves	BVPS-1 CR Intake	3.33E-04	2.38E-04	1.09E-04	7.88E-05	5.66E-05
U 2 MSL (break)/AEJ	BVPS-1 CR Intake	NA	NA	NA	NA	NA
U 2 Gaseous Waste Storage Vault	BVPS-1 CR Intake	NA	NA	NA	NA	NA
U 2 Containment Equipment Hatch	BVPS-1 CR Intake	NA	NA	NA	NA	NA
U 2 Contain. Edge	BVPS-2 CR Intake	NA	NA	NA	NA	NA
U 2 Containment Top	BVPS-2 CR Intake	NA	NA	NA	NA	NA
U 2 Ventilation Vent	BVPS-2 CR Intake	9.39E-04	6.69E-04	3.08E-04	2.23E-04	1.54E-04
U 2 RWST Vent	BVPS-2 CR Intake	NA	NA	NA	NA	NA
U 2 MS Relief Valves	BVPS-2 CR Intake	5.01E-04	3.58E-04	1.61E-04	1.19E-04	8.32E-05
U 2 MSL (break)/AEJ	BVPS-2 CR Intake	NA	NA	NA	NA	NA
U 2 Gaseous Waste Storage Vault	BVPS-2 CR Intake	NA	NA	NA	NA	NA
U 2 Containment Equipment Hatch	BVPS-2 CR Intake	NA	NA	NA	NA	NA
U 2 Contain. Edge	BVPS-2 Aux. Bldg. NW Corner	NA	NA	NA	NA	NA
U 2 Containment Top	BVPS-2 Aux. Bldg. NW Corner	NA	NA	NA	NA	NA
U 2 RWST Vent	BVPS-2 Aux. Bldg. NW Corner	NA	NA	NA	NA	NA
U 2 Contain. Edge	BVPS-1 Service Bldg.	NA	NA	NA	NA	NA
U 2 Containment Top	BVPS-1 Service Bldg.	NA	NA	NA	NA	NA
U 2 RWST Vent	BVPS-1 Service Bldg.	NA	NA	NA	NA	NA
U 2 Contain. Edge	ERF Intake	NA	NA	NA	NA	NA
U 2 Containment Top	ERF Intake	NA	NA	NA	NA	NA

Table 5.11.9-2B (continued) BVPS-2 On-Site Atmospheric Dispersion Factors (sec/m^3)						
Release	**Receptor**	**0-2 hr**	**2-8 hr**	**8-24 hr**	**1-4 d**	**4-30 d**
U 2 RWST Vent	ERF Intake	NA	NA	NA	NA	NA
U 2 Contain. Edge	ERF Edge Closest to Containment	NA	NA	NA	NA	NA
U 2 Containment Top	ERF Edge Closest to Containment	NA	NA	NA	NA	NA
U 2 RWST Vent	ERF Edge Closest to Containment	NA	NA	NA	NA	NA

Table 5.11.9-2C
ARCON96 Atmospheric Dispersion Factor Inputs
BVPS-1 Release Points

ARCON96 Parameter	Ventilation Vent		Main Steam Line Break/AEJ	
	Unit 1 CR Intake	Unit 2 CR Intake	Unit 1 CR Intake	Unit 2 CR Intake
Meteorological Information				
Period of Meteorological Data	1990 – 1994	1990 – 1994	1990 – 1994	1990 – 1994
Lower Measurement Height (m)	10.7	10.7	10.7	10.7
Upper Measurement Height (m)	45.7	45.7	45.7	45.7
Wind Speed Units	m/sec	m/sec	m/sec	m/sec
Meteorological Data File Names	arconbv.met	arconbv.met	arconbv.met	arconbv.met
Source Information				
Release Type	ground	ground	ground	ground
Release Height (m)	19.3	19.3	0.15(1)	3.6(1)
Building Area (m^2)	1,600	1,600	304.5	359.0
Vertical Velocity (m/sec)	0.0	0.0	0.0	0.0
Stack Flow (m^3/sec)	0.0	0.0	0.0	0.0
Stack Radius (m)	0.0	0.0	0.0	0.0
Receptor Information				
Distance to Receptor (m)	26.8	50.6	21.0	34.8
Intake Height (m)	0.15	3.6	0.15	3.6
Elevation Difference (m)	0.0	0.0	0.0	0.0
Direction to Source (deg)	202	216	311	269
Default Information				
Surface Roughness Length (m)	0.20	0.20	0.20	0.20
Wind Direction Window (deg)	90	90	90	90
Minimum Wind Speed (m/sec)	0.5	0.5	0.5	0.5
Averaging Sector Width Constant	4.3	4.3	4.3	4.3
Initial Diffusion Coefficients (m)	0.0, 0.0	0.0, 0.0	0.0, 0.0	0.0, 0.0

Notes:
(1) Release height conservatively set equal to the receptor height.

Table 5.11.9-2D
ARCON96 Atmospheric Dispersion Factor Inputs
BVPS-2 Release Point

ARCON96 Parameter	Ventilation Vent	
	Unit 1 CR Intake	Unit 2 CR Intake
Meteorological Information		
Period of Meteorological Data	1990 – 1994	1990 – 1994
Lower Measurement Height (m)	10.7	10.7
Upper Measurement Height (m)	45.7	45.7
Wind Speed Units	m/sec	m/sec
Meteorological Data File Names	arconbv.met	arconbv.met
Source Information		
Release Type	ground	ground
Release Height (m)	19.3	19.3
Building Area (m^2)	1,600	1,600
Vertical Velocity (m/sec)	0.0	0.0
Stack Flow (m^3/sec)	0.0	0.0
Stack Radius (m)	0.0	0.0
Receptor Information		
Distance to Receptor (m)	85.7	62.5
Intake Height (m)	0.15	3.6
Elevation Difference (m)	0.0	0.0
Direction to Source (deg)	59	61
Default Information		
Surface Roughness Length (m)	0.20	0.20
Wind Direction Window (degrees)	90	90
Minimum Wind Speed (m/sec)	0.5	0.5
Averaging Sector Width Constant	4.3	4.3
Initial Diffusion Coefficients (m)	0.0, 0.0	0.0, 0.0

Table 5.11.9-3 Analysis Assumptions and Key Parameter Values BVPS Common Control Room	
Control Room Parameters	
Free Volume	173,000 ft^3
Normal Operation Unfiltered Intake	500 cfm
Isolation Mode Unfiltered Inleakage (includes 10 cfm for egress/ingress)	300 cfm
Emergency Mode Intake Rate	600 to 1030 cfm
Emergency Mode Recirculation Rate	N/A
Emergency Mode Intake Filter Efficiency	99% (aerosols) 98% (elemental/organic iodine)
Emergency Mode Recirculation Filter Efficiency	NA
Emergency Mode Unfiltered Inleakage (includes 10 cfm for egress/ingress)	30 cfm
Occupancy Factors	(0-24 hr) 1.0 (1 – 4 days) 0.6 (4-30 days) 0.4
Operator Breathing Rate	(0-30 days) 3.5E-04 m^3/sec
Delay in Initiation of Control Room Emergency Ventilation due to LOOP	
Auto-Start on receipt of CIB (not credited in analysis)	
CR isolated (includes diesel start up/sequencing)	T=77 seconds
CR in emergency pressurization mode	T=137 seconds
Manual	
CR in emergency pressurization mode	T=30 minutes

Table 5.11.9-4A
Analysis Assumptions and Key Parameter Values
Main Steam Line Break(1) – BVPS-1

Core Power Level	2918 MWt
Reactor Coolant Mass (min)	340,711 lbm
Leakrate into Faulted Steam Generator	150 gpd @ STP
Amount of Accident Induced Leakage (AIL) into Faulted SG.	N/A
Maximum time to cool RCS to 212F	19 hrs
Leakrate into Intact Steam Generators	300 gpd total from 2 SGs @ STP
Failed/Melted Fuel Percentage	0%
RCS Tech Spec Iodine and NG Concentration	Table 5.11.4-1 (0.35 μCi/gm DE-I131)
RCS Equilibrium Iodine Appearance Rates	Table 5.11.4-2 (0.35 μCi/gm DE-I131)
Pre-Accident Iodine Spike Activity	Table 5.11.4-2 (21 μCi/gm DE-I131)
Accident Initiated Spike Appearance Rate	500 times equilibrium appearance rates
Duration of Accident Initiated Spike	4 hours
Secondary System Release Parameters	
Iodine Species released to Environment	97% elemental; 3% organic
Tech Spec Activity in SG liquid	Table 5.11.4-1(0.1μCi/gm DE-I131)
Iodine Partition Coefficient in Intact SG	100 (all tubes submerged)
Fraction of Noble Gas Released from Intact SG	1.0 (Released without holdup)
Fraction of Iodine Released form Faulted SG	1.0 (Released without holdup)
Fraction of Noble Gas Released from faulted SG	1.0 (Released without holdup)
Minimum Post-Accident Intact SG Liquid Mass	101,799 lbm per SG
Maximum Initial Liquid in each SG	101,799 lbm
Steam Releases from Intact SG	0-2 hr (345,000 lbm) 2-8 hr (734,000 lbm)
Dryout of Faulted SG	Instantaneous
Termination of release from Faulted SG	19 hours
Termination of release from Intact SG	8 hours
Release Point: Faulted SG	Break Point
Release Point: Intact SG	MSSV/ADVs
CR emergency Ventilation: Initiation Signal/Timing Manual	
CR pressurized and in Emergency Mode	T=30 minutes
Control Room Purge (Time/Rate)	24 hours after DBA @16,200 cfm (min) for 30 min

Notes:

(1) Steam generator parameter values reflect the Replacement Steam Generators.

Table 5.11.9-5A
Analysis Assumptions and Key Parameter Values
Steam Generator Tube Rupture(1) – BVPS-1

Core Power Level	2918 MWt
Reactor Coolant Mass	373,100 lbm
Break Flow to Faulted Steam Generator	0-225 sec (21,900 lbm) 225-1800 sec (128,000 lbm)
Time of Reactor Trip	225 sec
Termination of Release from Faulted SG	1800 seconds
Fraction of Break Flow that Flashes	0-225 sec (0.2227) 225-1800 sec (0.1645)
Leakage Rate to Intact Steam Generators	150 gpd @ STP for each SG
Failed/Melted Fuel Percentage	0%
RCS Tech Spec Iodine & NG Concentration	Table 5.11.4-1 (0.35 µCi/gm DE-I131)
RCS Equilibrium Iodine Appearance Rates	Table 5.11.4-2 (0.35 µCi/gm DE-I131)
Pre-Accident Iodine Spike Activity	Table 5.11.4-2 (21 µCi/gm DE-I131)
Accident Initiated Spike Appearance Rate	335 times equilibrium
Duration of Accident Initiated Spike	4 hours
Secondary System Release Parameters	
Intact SG Liquid Mass (min)	91,000 lbm
Faulted SG Liquid Mass (min)	91,000 lbm
Initial SG Liquid Mass per Steam Generators	96,000 lbm
Tech Spec Activity in SG liquid	Table 5.11.4-1 (0.1 µCi/gm DE-I131)
Form of All Iodine Released to the Environment via Steam Generators	97% elemental; 3% organic
Iodine Partition Coefficient (unflashed portion)	100 (all tubes submerged)
Fraction of Iodine Released (flashed portion)	1.0 (Released without holdup)
Fraction of Noble Gas Released from any SG	1.0 (Released without holdup)
Partition Factor in Condenser	100 elemental iodine 1 organic iodine/Noble Gases
Steam Flowrate to Condenser	0-225 sec (1207.407 lbm/sec per SG)
Faulted SG Steam Releases via MSSV/ADVs	225 sec – 1800 sec (68,900 lbm)
Intact SG Steam Releases via MSSV/ADVs	225 sec – 7200 sec (417,100 lbm) 2 hr – 8 hr (979,500 lbm)
Termination of Release from SGs	8 hours
Environmental Release Points	0-225 sec (Condenser Air Ejector) 225 sec –8 hr (MSSVs/ADVs)
CR Emergency Ventilation: Initiation Signal/Timing	
Control room is maintained in normal ventilation mode	
CR Purge Initiation (Manual)Time and Rate	8 hours after DBA @16,200 cfm (min) for 30 min

Notes:

(1) Steam generator parameter values reflect the Replacement Steam Generators.

Table 5.11.9-6
Analysis Assumptions & Key Parameter Values
Locked Rotor Accident(1) – BVPS-1 and BVPS-2

Core Power Level	2918 MWt
Minimum Reactor Coolant Mass	340,711 lbm
Primary to Secondary SG tube leakage	450 gpd @ STP
Melted Fuel Percentage	0%
Failed Fuel Percentage	20%
Core Activity of Isotopes in Gap	Table 5.11.4-3
Radial Peaking Factor	1.75
Fraction of Core Inventory in Fuel gap	I-131 (8%) Kr-85 (10%) Other Noble Gases (5%) Alkali Metals (12%)
Iodine Chemical Form in Gap	4.85% elemental 95% CsI 0.15% Organic
Secondary Side Parameters	
Minimum Post-Accident SG Liquid Mass	101,799 lbm per SG
Iodine Species released to Environment	97% elemental; 3% organic
Iodine Partition Coefficient in SGs	100 (all tubes submerged)
Particulate Carry-Over Fraction in SGs	0.0025
Steam Releases from SGs	0-2 hr (348,000 lbm) 2-8 hr (778,000 lbm)
Termination of releases from SGs	8 hours
Fraction of Noble Gas Released	1.0 (Released to Environment without holdup)
Environmental Release Point	MSSVs/ADVs
CR emergency Ventilation: Initiation Signal/Timing	
CR is maintained under Normal Operation ventilation	

Note:
(1) Bounding parameter values are used to encompass an event at either unit.

Table 5.11.9-7
Analysis Assumptions & Key Parameter Values
Loss of AC Power[1] – BVPS-1 and BVPS-2

Core Power Level	2918 MWt
Minimum Reactor Coolant Mass	340,711 lbm
Primary to Secondary SG tube leakage	450 gpd @ STP
Melted Fuel Percentage	0%
Failed Fuel Percentage	0%
RCS Tech Spec Iodine & NG Concentration	Table 5.11.4-1(0.35 µCi/gm DE-I131)
Secondary Side Parameters	
Minimum Post-Accident SG Liquid Mass	101,799 lbm per SG
Iodine Species released to Environment	97% elemental; 3% organic
Tech Spec Activity in SG liquid	Table 5.11.4-1 (0.1 µCi/gm DE-I131)
Iodine Partition Coefficient in SGs	100 (all tubes submerged)
Fraction of Noble Gas Released from SGs	1.0 (Released without holdup)
Steam Releases from SGs	0-2 hr (348,000 lbm) 2-8 hr (778,000 lbm)
Termination of releases from SGs	8 hours
Environmental Release Point	MSSVs/ADVs
CR emergency Ventilation: Initiation Signal/Timing	
CR is maintained under Normal Operation ventilation	

Note:
(1) Bounding parameter values are used to encompass an event at either unit.

Table 5.11.9-8
Analysis Assumptions and Key Parameter Values
Fuel Handling Accident in Fuel Pool Area or Containment – BVPS-1 and BVPS-2 (EPU Table)

(This table number is included to maintain numbering consistency with the EPU Licensing Report. The information in this table is not applicable for the RSG Licensing Report.)

Table 5.11.9-9 Analysis Assumptions and Key Parameter Values Small Line Break Outside Containment – BVPS-1 and BVPS-2	
Core Power Level	2918 MWt
Minimum Reactor Coolant Mass	340,711 lbm
CVCS letdown line break – mass flow rate	16.79 lbm/s
Break Flow Flash Fraction	37%
Time to isolate break-	15 minutes
Melted Fuel Percentage	0%
Failed Fuel Percentage	0%
RCS Tech Spec NG & Iodine Concentration	Table 5.11.4-1 (0.35 μCi/gm DE-I131)
RCS Equilibrium Iodine Appearance Rates	Table 5.11.4-2 (0.35 μCi/gm DE-I131)
Accident Initiated Spike Appearance Rate	500 times equilibrium
Duration of Accident Initiated Spike	4 hours
Iodine Species released to Environment	97% elemental; 3% organic
SLCRS Filter Efficiency	0%
Environmental Release Point	Ventilation Vent
CR Emergency Ventilation: Initiation Signal/Timing	
CR is maintained under Normal Operation ventilation	

Table 5.11.9-10
Analysis Assumptions and Key Parameter Values
Waste Gas System Rupture – BVPS-1 and BVPS-2 (EPU Table)

(This table number is included to maintain numbering consistency with the EPU Licensing Report. The information in this table is not applicable for the RSG Licensing Report.)

Table 5.11.9-11
Beaver Valley Power Station BVPS-1
Exclusion Area Boundary and Low Population Doses (TEDE)

Accident	EAB Dose (rem)[1,3]	LPZ Dose (rem)[2]	Regulatory Limit (rem)
Loss of Coolant Accident	No RSG Impact	No RSG Impact	–
Control Rod Ejection Accident[4]	3.1	1.5	6.3
Main Steam Line Break (U1)[7]	0.08 0.11	0.01 0.04	25(PIS) 2.5(CIS)
Main Steam Line Break (U2)[5][7]	NA	NA	NA
Steam Generator Tube Rupture (U1)[7]	2.27 0.93	0.14 0.06	25(PIS) 2.5(CIS)
Steam Generator Tube Rupture (U2)[7]	NA	NA	NA
Locked Rotor Accident	2	0.33	2.5
Loss of AC Power	(Note 6)	(Note 6)	2.5
Fuel Handling Accident BVPS-1 BVPS-2	 No RSG Impact NA	 No RSG Impact NA	–
Small Line Break Outside Containment	0.23	0.012	2.5
Waste Gas System Rupture	No RSG Impact	No RSG Impact	–

Notes:

(1) EAB Doses are based on the worst 2-hour period following the onset of the event.

(2) LPZ Doses are based on the duration of the release.

(3) Except as noted, the maximum 2 hr dose for the EAB is based on the 0-2 hr period:

- NA
- NA
- LR: 6 to 8 hr

(4) Dose values are based on the containment release scenario. The dose consequences based on the secondary side release scenario are 1 Rem (EAB) and 0.1 Rem (LPZ).

(5) NA

(6) Dose from a postulated Loss of AC Power is bounded by the Locked Rotor Accident.

(7) PIS: Pre-accident iodine spike; CIS: Concurrent iodine spike.

Table 5.11.9-12
30 Day Integrated Control Room Doses (TEDE)

Accident	Control Room Operator	
	Dose (rem)	Reg. Limit (rem)
Loss of Coolant Accident[1] (LOCA)	No RSG Impact	–
Control Rod Ejection Accident[2] (CREA)	1.3	5
Main Steam Line Break (U1)[5] (MSLB)	0.66	5
Main Steam Line Break (U2)[3X5]	NA	NA
Steam Generator Tube Rupture (U1)[5X6] (SGTR)	1.95	5
Steam Generator Tube Rupture (U2)[5X6]	NA	NA
Fuel Handling Accident[6] BVPS-1[5] BVPS-2	 No RSG Impact NA	–
Locked Rotor Accident[6] (LRA)	2.2	5
Loss of AC Power[6] (LACP)	(Note 4)	5
Small Line Break Outside Containment[6] (SLB)	0.7	5
Waste Gas System Rupture[6] (WGSR)	No RSG Impact	–

Notes:

(1) NA

(2) Dose values are based on the containment release scenario. The dose consequences based on the secondary side release scenario is 0.06 Rem.

(3) NA

(4) Dose from a postulated Loss of AC Power is bounded by the Locked Rotor Accident.

(5) The CR is purged for 30 minutes at 16,200 cfm following termination of the environmental releases and by:

- MSLB: Purge within 24 hrs
- SGTR: Purge within 8 hrs
- NA

(6) The following accidents do not take credit for CREVS operations: SGTR, LRA, LACP, and SLB outside Containment.

5.12 FIRE PROTECTION SAFE SHUTDOWN (APPENDIX R) (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

6 FUEL ANALYSIS

This section describes the analyses and evaluations performed in the nuclear fuel and fuel-related areas to support the EPU Project. The section addresses analyses and evaluations performed for fuel thermal-hydraulic design, fuel nuclear core design, fuel rod design and performance, heat generation rates, and neutron fluence.

The analyses and evaluations presented in this section support operation of BVPS-1 at EPU conditions with the Model 54F replacement steam generators (RSGs). The analyses and evaluations for EPU conditions bound and support operation at the current power level.

The analyses and evaluations for the nuclear fuel and fuel-related areas at EPU conditions use a total core peaking factor (F_Q) of 2.4 or 2.52 and a nuclear enthalpy rise hot channel factor ($F_{\Delta H}$) of 1.62 or 1.75. In all cases, the nuclear fuel and fuel-related analyses and evaluations for EPU conditions support a minimum F_Q of 2.4 and a minimum $F_{\Delta H}$ of 1.62. The use of larger peaking factors in select analyses and evaluations supports the potential for a future increase in peaking factors at EPU conditions.

Fuel Assembly Design

To support EPU, the fuel assembly design for BVPS was changed from the 17×17 VANTAGE 5H/PERFORMANCE+ (w/o Intermediate Flow Mixing (IFM) grids) design to the 17×17 Robust Fuel Assembly (RFA) design (w/ IFMs), including the RFA-2 design. The RFA-2 design is essentially identical to the RFA design except that it includes an enhanced mid grid design that results in increased mid grid contact area with the fuel rod. The enhanced mid grid design has no impact on the fuel assembly thermal hydraulic, neutronics, or structural models. The RFA design contains a mid grid allowable structural limitation that is conservative with respect to the RFA-2 design. The analyses and evaluations performed for RFA fuel also apply to RFA-2 fuel, and the term RFA fuel as used in this report includes applicability to RFA-2 fuel.

The transition to RFA fuel was initiated at the current core power level (2689 MWt). It is anticipated that the fuel transition will be complete and the entire core will consist of RFA fuel when EPU is implemented. Although the core will be fully transitioned to RFA fuel when EPU is implemented, previously burned VANTAGE 5H fuel assemblies may be reinserted into the core as part of a cycle specific reload. The VANTAGE 5H fuel design is mechanically and hydraulically compatible with the RFA fuel design. The acceptability of reinserting VANTAGE 5H fuel assemblies into the core will be confirmed during the normal reload design process for the specific loading pattern chosen for that reload design.

A description of the RFA and V5H fuel assembly mechanical design features is provided in this section.

Fuel Mechanical Design Features

This section describes the mechanical design and the compatibility of the 17×17 RFA fuel assembly design (w/ IFMs) and the VANTAGE 5H/PERFORMANCE+ (w/o IFMs) fuel assembly design. The RFA fuel assembly is designed to be compatible with the VANTAGE 5H fuel assembly, reactor internals interfaces, the fuel handling equipment and refueling equipment. The RFA design dimensions are

essentially equivalent to the VANTAGE 5H assembly design from an exterior assembly envelope and reactor internals interface standpoint.

The significant mechanical features of the RFA design that differ from the VANTAGE 5H design are the addition of three IFM grids, modification to the mixing vane mid grids, and increased thimble and instrument tube outer diameters. Details of the RFA fuel assembly design are presented in the following sections.

Design Description of the 17×17 Robust Fuel Assembly

The 17×17 RFA design is a 17×17 array with the standard fuel rod design 0.374 in. rod outside diameter. The design incorporates and adapts many of the current Westinghouse advanced fuel features, including:

- ZIRLO™ thick thimble and instrument tubes
- Removable Top Nozzle (RTN)
- Reduced Rod Bow (RRB) Inconel Top Grid
- ZIRLO™ Modified Low Pressure Drop (LPD) Structural Mid Grids
- ZIRLO™ Modified Intermediate Flow Mixing Grids
- High Burnup Inconel Bottom Grid
- Debris Filter Bottom Nozzle
- Inconel Protective Bottom Grid
- Zirconium oxide coating on the bottom section of the fuel rod
- Debris mitigating long fuel rod bottom end plugs
- ZIRLO™ Clad Fuel Rods

The 17×17 RFA design is a VANTAGE 5H/PERFORMANCE+ design (STD fuel rod size of 0.374 in. outer rod diameter) using LPD structural and IFM grids of a modified design.

The RFA design incorporates three ZIRLO™ IFM grids. The RFA design is mechanically and hydraulically compatible with the VANTAGE 5H (w/o IFMs), and the same functional requirements and design criteria apply to the Westinghouse RFA fuel assemblies and VANTAGE 5H (w/o IFMs) fuel assemblies.

Fuel Rods

The RFA fuel rod has the same clad wall thickness, fuel rod pellet stack active length, fuel rod diameter, bottom end plug and cladding material (ZIRLO™) as the VANTAGE 5H fuel rod.

Grid Assemblies

The RFA fuel includes IFM grids. The IFM's primary function is to promote flow mixing. Additionally, they limit rod bow in the hottest fuel assembly spans. They must accomplish this without inducing clad wear beyond established limits. The IFMs must avoid interactive damage with grids from neighboring fuel assemblies during core loading or unloading operations.

The IFM grids are located in the three uppermost spans between the ZIRLO™ mixing vane structural grids and incorporate a similar mixing vane array. Their prime function is mid-span flow mixing in the hottest fuel assembly spans. Each IFM grid cell contains four dimples which are designed to prevent mid-span channel closure in the spans containing IFMs and fuel rod contact with the mixing vanes. This simplified cell arrangement allows short grid cells so that the IFM can accomplish its flow mixing objective with minimal pressure drop.

The IFM grids and mixing vane grids are fabricated from ZIRLO™. This material was selected to take advantage of the material's inherent low neutron capture cross section.

The RFA mid grid has a mixing vane pattern. Differences between the RFA mid grids and IFM grids, and the VANTAGE 5H fuel include:

- Mixing vane pattern
- Vane geometry
- Spring and dimple geometry
- Intersect slot length

To allow for the larger thimble and instrument tubes, the RFA mid grids and IFM grids are embossed (radiused) at the thimble cell locations to accept the larger diameter thimble tube.

The Inconel bottom and protective bottom grids are the same for RFA and VANTAGE 5H except for the larger insert inner diameter.

Guide Thimble and Instrument Tubes

The RFA design incorporates thicker walled thimble and instrumentation tubes relative to the VANTAGE 5H fuel design. The guide thimble and instrumentation tube wall thickness is increased to improve stiffness and address incomplete rod insertion (IRI) considerations. The major outer diameter (above the dashpot) is increased to 0.482 in. from 0.474 in. for the RFA design, relative to the VANTAGE 5H, and the minor OD is increased to 0.439 in. from 0.430 in. There is no difference in major or minor (dashpot) inner diameters.

The new thimble dashpot OD (0.439 in.) requires new bottom/protective bottom grid insert tubing. The insert tube ID was increased to interface with the larger thimble tube and the guide thimble end plug was modified to a slip fit interface with the thimble tube. This results in a minimal diameter increase locally at the weld and additional margin for fit up in the insert assembly. Since the thimble tube major OD is the same as the 17×17 STD product, the RTN insert interface with the thimble tube is acceptable without a design change to the insert or lock tube. Additionally, the instrument tube socket counter bore in the debris filter bottom nozzle (DFBN) required modification to accommodate the larger instrument tube.

Mechanical Performance

Design changes associated with the addition of the three IFM grids do not significantly influence the RFA fuel assembly structural characteristics that were determined by prior mechanical testing. Therefore,

the RFA fuel assembly structural behavior and projected performance remain consistent with the VANTAGE 5H fuel assembly design.

Core Components

The core components for BVPS are designed to be compatible with the RFA and VANTAGE 5H fuel assembly designs.

Table 6.0-1
17x17 Robust Fuel Assembly and 17x17 VANTAGE 5H Fuel Assembly Design

Design Feature	Westinghouse 17x17 VANTAGE 5H (w/o IFMs)	Westinghouse 17x17 RFA and RFA-2[1] (w/ IFMs)
FUEL ASSEMBLY		
Rod Array in Assembly	17x17	17x17
Rods per Assembly	264	264
Assembly Pitch, in.	8.466	8.466
Overall Assembly Envelope, in.	8.426	8.426
Overall Assembly Height, in.	159.775	159.975
Fuel Assembly Weight, lb. (6" Annular Blankets)	~1436	~1456
Fuel Assembly Weight (Solid Blankets)	~1469	~1478
BOTTOM/PROTECTIVE GRID		
Insert Tubing, OD x ID, in.	0.4835 x 0.4455	0.4840 x 0.4500
BOTTOM NOZZLE		
Instrument Counter Bore Diameter, in.	0.477	0.484
MID GRID		
Mid Grid Material	ZIRLO™	ZIRLO™
Mid Grid Envelope, in.	8.418	8.418
Vane Pattern[1]	[ ]a,c	[ ]a,c
Vane Length (Unbent), in.[1]	[ ]a,c	[ ]a,c
Spring Window, in.	[ ]a,c	[ ]a,c
Dimple Slot, in.[1]	[ ]a,c	[ ]a,c
Spring/Dimple Forms[1]	Standard Design	[ ]a,c
Intersect Slot Length, in.	[ ]a,c	[ ]a,c
Inner Strap Height, in.	1.500	1.500
Inner Strap Thickness, in.	0.018	0.018
Outer Strap Design	Standard Design	Anti-Snag
Outer Strap Height, in.	1.875	1.878
Outer Strap Thickness, in.	0.026	0.026
Sleeve Diameters, OD x ID, in.	0.514 x 0.480	0.528 x 0.494
IFM GRID		
IFM Grid Material	N/A	ZIRLO™
Envelope, in.	N/A	8.386
Vane Pattern	N/A	[ ]a,c
Vane Length (Unbent), in.	N/A	[ ]a,c
Dimple Slot, in.	N/A	[ ]a,c
Dimple Forms	N/A	[ ]a,c
Inner Strap Height, in.	N/A	0.475
Inner Strap Thickness, in.	N/A	0.018
Outer Strap Design	N/A	Anti-Snag
Outer Strap Height, in.	N/A	1.363
Outer Strap Thickness, in.	N/A	0.026
Sleeve Diameters, OD x ID, in.	N/A	0.528 x 0.494

Note
(1) RFA and RFA-2 fuel assemblies have mid grids that differ slightly. The RFA and RFA-2 mid grid data in the table applies to both fuel assemblies, but RFA-2 mid grids have slight differences in the spring slots, width and contact face with a localized increase in dimple width at the contact face.

6.1 FUEL THERMAL-HYDRAULIC DESIGN

6.1.1 Introduction

The fuel assemblies to be used in the BVPS cores at EPU conditions consist of Robust Fuel Assemblies (with Intermediate Flow Mixers) (RFA), however, previously burned VANTAGE 5H fuel assemblies may be reinserted in BVPS cores at EPU conditions. The DNB methodology used is the Revised Thermal Design Procedure (RTDP) (Reference 1) with the VIPRE code.

This section describes the calculational methods and analyses performed to support the EPU to a maximum core power of 2900 MWt.

6.1.2 Input Parameters and Assumptions

Table 6.1-1 summarizes the thermal-hydraulic design parameters analyzed in support of the BVPS operation at an EPU core power of 2900 MWt.

6.1.3 Description of Analyses and Evaluations

6.1.3.1 DNBR Calculational Methods

The RTDP (Reference 1) will continue to be used where applicable. The DNBR analysis is performed with the VIPRE code as generically approved by the NRC (Reference 2). This is a first time application of the VIPRE code to BVPS. The WRB-2M DNB correlation (Reference 3) is used for the RFA with the WRB-2 (References 4, 9 and 10), WRB-1 (Reference 7), or W-3 correlations (References 5 and 6) used where WRB-2M is not applicable. The WRB-1 DNB correlation will continue to be used for any reinserted V5H fuel assemblies with the W-3 correlation used where WRB-1 is not applicable. The DNB correlation limit is that value of DNBR, based on statistical analysis of the DNB test data, for which there is a 95% probability that DNB will not occur at a 95% confidence level. The limits are 1.14 for WRB-2M, 1.17 for WRB-1 and WRB-2, and 1.30 for W-3 (1.45 for low pressures).

With RTDP methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes and DNB correlation uncertainties are combined statistically to obtain the overall DNB uncertainty factor which is used to calculate the DNBR Design Limits (DL) that satisfy the DNB design criterion. The criterion is that the probability that DNB will not occur on the most limiting rod is at least 95% at a 95% confidence level for any Condition I or II event. Since the parameter uncertainties are considered in determining the RTDP design limit, the plant safety analyses are performed using input parameters at their nominal values. The DNBR Safety Analysis Limits (SAL) are defined as SAL DNBR = DL DNBR/(1-M) where M is the plant specific margin that is maintained for the purpose of offsetting DNBR penalties such as rod bow and transition core penalties and increasing the flexibility in design and operation of the plant.

The RTDP uncertainties included are the nuclear enthalpy rise hot channel factor ($F_{\Delta H}$), the enthalpy rise engineering hot channel factor ($F^{E}_{\Delta H,I}$), uncertainties in the VIPRE and transient codes and uncertainties based on surveillance data associated with vessel coolant flow, core power, coolant temperature, system

pressure and effective core flow fraction (i.e., bypass flow). The increase in DNB margin is realized when nominal values of the preceding factors are used in the DNB safety analyses. The following bounding instrumentation uncertainties were used to determine the DNBR Design Limits:

Power	0.6%
RCS Flow	2.2%
Pressure	37.6 psi
Inlet Temperature	4.0°F

The RTDP DNBR Design Limit values calculated corresponding to the 2900 MWt core power parameters were 1.22/1.22 (typical cell/thimble cell) for RFA. DNB margin was obtained by performing the safety analyses to the Safety Analyses DNBR limits which are higher than the Design Limits. The DNBR margin/penalty summary for transients using RTDP is given in Table 6.1-2. The unused DNBR margin is available for operating and design flexibility.

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 DNBR Margin/Penalty Summary for transients using STDP is given in Table 6.1-3.

6.1.3.2 DNB Performance

The following calculations were performed, using RTDP methodology, to support the EPU to 2900 MWt core power. Revised Core and Axial Offset Limits were calculated. These were used as input to determine the revised Overtemperature Delta T and Overpower Delta T trip setpoints. Calculations were made for Loss of Flow (including Complete Loss of Flow, Frequency Decay and Partial Loss of Flow), Locked Rotor, Dynamic Dropped Rod and Static Rod Misalignment. All DNBR Safety Analysis Limits were met.

The analyses of Hot Full Power and Hot Zero Power Steam Line Break, Feedwater Malfunction and Rod Withdrawal From Subcritical were done using STDP methodology. As stated above, the DNBR limits for STDP are the appropriate DNB correlation limits increased by sufficient margin to offset applicable DNBR penalties. All DNBR limits were met.

The Hot Full Power Steam Line Break transient was analyzed with the W-3 DNB correlation. The applicable correlation limit (CL) was 1.30. The minimum DNBRs were greater than the DNBR limit of 1.50. The only applicable penalty was that due to rod bow, equal to 5.5% in the lower grid spans. The DNBR margin ((1 – (CL/DNBR limit)) x 100) is more than sufficient to cover this penalty.

The Hot Zero Power Steam Line Break transient was analyzed with the W-3 DNB correlation. The applicable correlation limit was 1.45, since the core pressure was below 1000 psia. The minimum DNBRs were greater than the DNBR limit of 1.61. The Feedwater Malfunction transient was bounded by the Hot Zero Power Steam Line Break transient.

The Rod Withdrawal From Subcritical transient was analyzed with the W-3 DNB correlation with a correlation limit of 1.30 below the first mixing vane grid. The analysis above the first mixing vane grid used the WRB-1 DNB correlation with a correlation limit of 1.17. The DNBR limit used below the first mixing vane grid was 1.65. Use of this limit covers all applicable DNB penalties with margin. The DNBR limit used above the first mixing vane grid was 1.45. In all cases, the minimum DNBRs were higher than the limit.

6.1.3.3 Effects of Rod Bow on DNBR

The phenomenon of fuel rod bowing is accounted for in the DNBR safety analysis of Condition I and II events. The maximum rod bow penalty applicable to the RFA in the 20-inch grid spans is 1.3% DNBR at an assembly average burnup of 24000 MWD/MTU. For burnups greater than 24000 MWD/MTU, credit is taken for the effect of $F_{\Delta H}$ burndown, due to the decrease in fissionable isotopes and the buildup of fission product inventory. Therefore, no additional rod bow penalty is required at burnups greater than 24000 MWD/MTU. No rod bow penalty is applicable to the RFA in the 10-inch grid spans.

For this application, the rod bow penalty is offset with the DNB margin retained between the DNBR Design and Safety Analysis Limits, Table 6.1-2.

6.1.3.4 Fuel Temperature Analysis

The PAD 4.0 code as generically approved by the NRC (Reference 8) was used to calculate the fuel temperature data that is used as initial conditions for the LOCA and non-LOCA safety analyses.

6.1.4 Acceptance Criteria and Results

The acceptance criteria and results for the fuel thermal-hydraulic design analyses and evaluations are included in Section 6.1.3.

6.1.5 Conclusions

The thermal hydraulic evaluation of the EPU to 2900 MWt core power for BVPS has shown that sufficient DNB margin is available to cover the applicable penalties and satisfy acceptance criteria.

The results and conclusions of the fuel thermal-hydraulic design analyses and evaluations performed for the core power of 2900 MWt bound and support operation at the current core power of 2689 MWt.

6.1.6 References

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2. Sung, Y. X., et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A and WCAP-15306-NP-A, October 1999.

3. Smith, L. D., et al., "Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17×17 Rod Bundles with Modified LPD Mixing Vane Grids," WCAP-15025-P-A, April 1999.

4. Davidson, S. L. and Kramer, W. R. (Ed.), "Reference Core Report VANTAGE 5 Fuel Assembly," WCAP-10444-P-A, September 1986.

5. Tong, L. S., "Boiling Crisis and Critical Heat Flux," AEC Critical Review Series, TID-25887, 1972.

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7. Motley, F. E. et al., "New Westinghouse Correlation WRB-1 for Predicting Critical Heat Flux in Rod Bundles with Mixing Vane Grids," WCAP-8762-P-A, July 1984.

8. Slagle, W. H., (ed.) et al., "Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)," WCAP-15063-P-A, Revision 1, July 2000.

9. Letter from N. J. Liparulo (Westinghouse) to J. E. Lyons (NRC), "Transmittal of Response to NRC Request for Information on Wolf Creek Fuel Design Modifications," NSD-NRC-97-5189, June 30, 1997.

10. Letter from H. Sepp (Westinghouse) to T. E. Collins (NRC), "Fuel Criteria Evaluation Process Notification for the 17×17 Robust Fuel Assembly with IFM Grid Design," NSD-NRC-98-5796, October 13, 1998.

Table 6.1-1
Thermal and Hydraulic Design Parameters

Thermal and Hydraulic Design Parameters (using RTDP)	Design Parameters
Reactor Core Heat Output, MWt	2900
Reactor Core Heat Output, 10^6 BTU/hr	9895
Heat Generated in Fuel, %	97.4
Core Pressure, Nominal, psia high flow low flow	 2270 2260
Pressurizer Pressure, Nominal, psia	2250
Radial Power Distribution(1)	1.62(1+0.3(1-P)) (2) where P = Fraction of Full Power
HFP Nominal Coolant Conditions	**Design Parameters**
Vessel Thermal Design Flow (TDF) Rate (including Bypass), 10^6 lbm/hr GPM	 99.3 261,600
Core Flow Rate (excluding Bypass, Based on TDF) 10^6 lbm/hr GPM	 92.8 244,600
Core Flow Area, ft^2	41.55
Core Inlet Mass Velocity, 10^6 lbm/hr-ft^2 (Based on TDF)	2.10
Thermal and Hydraulic Design Parameters (based on TDF)	**Design Parameters**
Vessel/Core Inlet Temperature, °F Vessel Average Temperature, °F Core Average Temperature, °F Core Outlet Temperature, °F Vessel Outlet Temperature, °F Average Temperature Rise in Vessel, °F Average Temperature Rise in Core, °F	543.1 580.0 584.6 621.4 617.0 73.9 78.3
Heat Transfer Active Heat Transfer Surface Area, ft^2 Average Heat Flux, BTU/hr-ft^2 Average Linear Power, kw/ft Peak Linear Power for Normal Operation, kw/ft(3) Peak Linear Power for Prevention of Centerline Melt, kw/ft	 48,600 198,300 5.69 14.3 22.4
Pressure Drop Across Core, psi(4)	22.48 (BVPS-1)

Notes:

(1) RTDP analysis excludes the 4% measurement uncertainty that is included in theses values.

(2) A reduced peaking factor (1.456) would be used for the analysis of any reinserted V5H fuel assemblies in order to meet the DNBR limits at the EPU conditions. The reduced peaking factor is achievable due to the significant burnup of the V5H fuel assemblies.

(3) Based on maximum FQ of 2.52, which supports the minimum FQ of 2.4.

(4) Based on best estimate flow rate of 293,400 gpm (BVPS-1).

Table 6.1-2
DNBR Margin/Penalty Summary (RTDP)[3]

DNB Correlation		WRB-2M
DNBR Correlation Limit		1.14
DNBR Design Limit	(Typical cell) (Thimble cell)	1.22 1.22
DNBR Safety Analysis Limit	(Typical cell) (Thimble cell)	1.55 1.55
DNBR Margin, %	(Typical cell) (Thimble cell)	21.2[1] 21.2[1]
Rod Bow DNBR Penalty, %		1.3 (20" span) 0 (10" span)[2]
Available Unused DNBR Margin, %	(Typical cell) (Thimble cell)	21.2[2] 21.2[2]

Notes:

(1) DNBR margin (M) between Safety Analysis Limit (SAL) and Design Limit (DL) DNBRs: M = 1 – DL/SAL.

(2) Minimum DNBRs occur in IFM spans for RTDP.

(3) Burned V5H fuel assemblies have also been evaluated in BVPS cores at EPU conditions. The reinsertion of burned V5H fuel assemblies at EPU conditions would be further evaluated as part of the normal reload process.

Table 6.1-3
DNBR Margin/Penalty Summary (STDP)[2]

Hot Zero Power Steamline Break		
DNB Correlation		W-3
DNBR Correlation Limit	(Typical cell) (Thimble cell)	1.45 1.45
DNBR Limit[1]	(Typical cell) (Thimble cell)	1.61 1.61
Hot Full Power Steamline Break		
DNB Correlation		W-3
DNBR Correlation Limit	(Typical cell) (Thimble cell)	1.30 1.30
DNBR Limit[1]	(Typical cell) (Thimble cell)	1.50 1.50
Rod Withdrawal from Subcritical		
Below first mixing vane grid		
DNB Correlation		W-3
DNBR Correlation Limit	(Typical cell) (Thimble cell)	1.30 1.30
DNBR Limit[1]	(Typical cell) (Thimble cell)	1.65 1.65
Remaining grid spans		
DNB Correlation		WRB-1
DNBR Correlation Limit	(Typical cell) (Thimble cell)	1.17 1.17
DNBR Limit[1]	(Typical cell) (Thimble cell)	1.45 1.45

Notes:

(1) The STDP DNBR Limits are analogous to the RTDP Safety Analysis Limits and include margin to cover applicable penalties.

(2) Burned V5H fuel assemblies have also been evaluated in BVPS cores at EPU conditions. The reinsertion of burned V5H fuel assemblies at EPU conditions would be further evaluated as part of the normal reload process.

6.2 FUEL NUCLEAR CORE DESIGN (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

6.3 FUEL ROD DESIGN AND PERFORMANCE (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

6.4 REACTOR INTERNALS HEAT GENERATION RATES (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

6.5 NEUTRON FLUENCE (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

7 CONTAINMENT ANALYSIS

The EPU Project included containment analysis for BVPS-1 at the EPU conditions associated with the NSSS power of 2910 MWt. The analysis also included initial conditions and assumptions necessary to support conversion of the containment design basis from sub-atmospheric to atmospheric consistent with a large dry atmospheric containment design. For BVPS-1, the analysis was performed to support the Model 54F replacement steam generators (RSGs). Unit specific analyses were performed for BVPS-1. This containment analysis was previously submitted to the NRC for review and approval as part of the Beaver Valley Power Station Containment Conversion License Amendment Request LAR No. 317 (BVPS-1).

The results and conclusions of the containment analysis performed for the NSSS power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt.

8 BOP ANALYSIS (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

9 PLANT SYSTEMS (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10 GENERIC PROGRAMS

Extended power uprate (EPU) with Model 54F replacement steam generators (RSGs) has the potential to affect systems, structures, and components (SSCs) contained within programs that have been developed and implemented by station personnel to demonstrate that topical areas comply with various design and licensing requirements. The plant programs and/or issues listed in Table 10-1 were reviewed to determine the impact due to the EPU with RSGs. For the programs listed in Table 10-1, the controlling procedures and processes for the programs and key reference items within the procedures were reviewed. Program sponsors, implementing organization personnel and other cognizant individuals were interviewed for those issues and programs that would be impacted by the EPU with RSGs. Based upon the review of this information, the extent of impact by the implementation of the EPU with RSGs was determined for the various issues and programs. The results of the review are summarized in Table 10-1 and discussed below.

Table 10-1
Generic Programs and Issues

Section	Programs/Issues	Update Required[1]
10.1	Motor-Operated Valve Program	NA
10.2	Air-Operated Valve (AOV) Program	NA
10.3	Generic Letter 89-13 River/Service Water System Control and Monitoring	NA
10.4	Inservice Inspection (ISI) Program	NA
10.5	Inservice Test (IST) Program	NA
10.6	Containment Leak Rate Testing	NA
10.7	Station Blackout (SBO)	NA
10.8	Human Factors	NA
10.9	Plant Simulator	NA
10.10	Equipment Qualification	Yes
10.11	Seismic and Dynamic Qualification of Mechanical and Electrical Equipment	NA
10.12	Flood Protection	NA
10.13	Internally Generated Missiles Inside and Outside Containment	NA
10.14	Protective Coating Systems (Paints) – Organic Materials	NA
10.15	Operating Procedures/Training	NA
10.16	Probabilistic Risk Assessment (PRA)	NA

Note:
(1) The designation "NA" indicates that program impact due to operation of BVPS-1 with RSGs at the current power level is being addressed under the provisions of 10 CFR 50.59.

10.1 MOTOR OPERATED VALVES (MOVS) (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.2 AIR OPERATED VALVE (AOV) PROGRAM (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.3 GENERIC LETTER 89-13 RIVER/SERVICE WATER SYSTEM CONTROL AND MONITORING (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.4 INSERVICE INSPECTION (ISI) PROGRAM (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.5 INSERVICE TESTING (IST) PROGRAM (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.6 CONTAINMENT LEAK RATE TESTING (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.7 STATION BLACKOUT (SBO) (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.8 HUMAN FACTORS (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.9 PLANT SIMULATOR (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.10 EQUIPMENT QUALIFICATION

10.10.1 Introduction

This section addresses the impact on the Environmental Qualification (EQ) of safety-related electrical equipment/components (EQ equipment currently included in the BVPS-1 EQ Program) due to operation at the increased reactor power level of 2900 MWt, with an atmospheric containment (versus sub-atmospheric) and full RSG on BVPS-1. References to EPU conditions throughout this section is understood to include the change due to containment conversion and full RSG (BVPS-1). These operational conditions result in specific changes to some of the current pre-EPU BVPS-1 environmental parameters specified within documented EQ equipment evaluations.

The revised environmental qualification conditions were compared to the current environmental qualification requirements. Where the current requirements have been exceeded, the evaluation of the EQ equipment qualification assessed the impact and confirmed its acceptability at the revised conditions.

The BVPS Containment Conversion License Amendment Request No. 317 (BVPS-1) discussed the EQ equipment qualification for operation as an atmospheric containment. This LAR evaluated in-containment normal and accident temperature/pressure conditions. That submittal also addressed the Main Steam Valve House MSL break for BVPS-1 due to the addition of cavitating venturis in the Auxiliary Feedwater lines. The Service Building and Turbine Building were also addressed. The License Amendment also addressed radiological impacts.

10.10.2 Environmental Parameters

Post-EPU operation involves an increase in steam flow and in reactor core power level. These operational increases impact the following EQ equipment environmental parameter requirements.

- Revised Loss of Coolant Accidents (LOCAs)/Main Steam Line Breaks (MSLBs) accident temperature and pressure profiles inside the Containments, based upon worst-case peak conditions for containment conversion. These increases were included in LAR 317 submittal.

- Revised accident temperature and pressure (versus time) profiles inside the Main Steam Valve Houses and Service Buildings based on EPU conditions. Evaluations have shown that profile increases result when the RSG is considered. Those increases have been determined to be acceptable.

- Increased total integrated doses (TIDs) postulated for normal and accident conditions associated with the increased fission product and activation product inventories in the reactor coolant, commensurate with operation at the revised conditions.

For completeness, the following environmental parameters were considered within the overall evaluation at revised conditions:

- Normal and Accident Pressure Inside Containment (see LAR 317)
- Normal and Accident Pressures Outside Containment (see evaluation results below)

- Normal Temperature Inside and Outside Containment (not impacted as noted below)
- Accident Temperatures Inside Containment (see LAR 317)
- Accident Temperatures Outside Containment (see LAR 317)
- Normal and Accident Radiation Inside Containment (see Section 5.11)
- Normal and Accident Radiation Outside Containment (see Section 5.11)
- Normal and Accident Humidity Inside and Outside Containment (not impacted as noted below)

10.10.3 Description of Methods and Analysis

The post-EPU qualification of EQ equipment was evaluated to ensure that the above noted environmental parameters and anticipated environmental increases do not adversely affect the capability of safety-related equipment to perform their intended safety function. This evaluation was completed by: comparing current EQ requirements (defined within existing EQ packages) to post-EPU EQ requirements (consistent with the above noted anticipated environmental increases); and identifying increases for their impact to the existing EQ packages documentation of equipment configuration and performance. The following discussion summarizes each of the above noted qualification parameters for change due to the EPU and the resulting impact on equipment qualification.

1. Normal and Accident Pressure Inside Containment:

   Pressure effects on EQ equipment qualification were evaluated by comparison of the revised pressures to the current qualification pressure requirements. These parameters are addressed in LAR No. 317 (BVPS-1). All safety-related EQ equipment was found capable of the revised pressures.

2. Normal and Accident Pressures Outside Containment:

   There are no post-EPU effects/changes to the normal peak pressure conditions for EQ equipment qualification, based upon the comparison between the normal pre-EPU and post-EPU conditions. Accident peak pressure results postulated for Main Steam line breaks were compared to the initial qualification pressures, in a manner similar to the corresponding Main Steam line break temperatures (as noted by Item 5 below).

3. Normal Temperature Inside and Outside Containment:

   There are no post-EPU changes to the maximum normal operating temperatures inside or outside the Containment. Therefore there are no effects on the qualified life of EQ equipment located inside or outside Containment. The normal operating temperatures are discussed in LAR No. 317 (BVPS-1).

4. Accident Temperatures Inside Containment:

   LAR No. 317 (BVPS-1) addressed the combined CC, EPU, and RSG (BVPS-1) accident temperature impacts for equipment inside Containment. The combined containment pressure/temperature calculations generated temperature profiles that were compared to the Equipment Qualification profiles and with the Post Accident Operating Time (PAOT)

temperature. Equipment where the analysis exceeded the Equipment Qualification profiles and/or the PAOT temperature were verified to be qualified by the equipment qualification test report data.

5. Accident Temperatures Outside Containment:

   Accident temperatures outside the Containment are addressed for Main Steam line breaks in the Main Steam Valve House and the Service Building. The review evaluated the specific EQ equipment in these impacted areas (while exposed to these increased accident temperature requirements) with respect to its active safety related function. LAR No. 317 (BVPS-1) discussed the Main Steam Valve House break for BVPS-1 due to the addition of cavitating venturis in the Auxiliary Feedwater lines. Service Building Main Steam line breaks also are discussed below.

6. Normal and Accident Radiation Inside Containment:

   EPU scaling factors were determined to evaluate/compare the changes in pre-EPU radiation TID values to those used for the post-EPU equipment qualification. Cases where application of the scaling factors resulted in doses greater than the pre-EPU equipment qualification dose were reviewed further to incorporate applicable TID reductions (for example, the location specific equipment exposure conditions and/or configurations reduced the conservatively-assumed beta radiation requirements included in the pre-EPU TID value, owing to beta shielding of its sealed components).

7. Normal and Accident Radiation Outside Containment:

   EPU scaling factors were determined to evaluate/compare the changes in pre-EPU radiation TID values to those for the post-EPU equipment qualification. Equipment whose radiation qualification could not be directly confirmed using these scaling factors was further evaluated based upon: additional analysis of the local conditions; refined radiation calculations; application of alternative test data; and/or evaluation of post-EPU accident operational requirements.

8. Normal and Accident Humidity Inside and Outside Containment:

   Humidity was reviewed for change. No changes to the normal and accident humidity conditions were identified for EPU operation.

10.10.4 Evaluation Results

The BVPS-1 EQ equipment has been evaluated for the environmental parameters changed by the EPU. The results confirm that the EQ equipment is qualified for the EPU environmental parameters as described below.

1. Normal and Accident Pressure Inside Containment:

   As described in LAR No. 317 (BVPS-1) the evaluation was done for the combination of CC, EPU, and RSG (BVPS-1 only). The accident pressures are within the peak of the existing qualification accident pressure.

2. Normal and Accident Pressures Outside Containment:

   There are no post-EPU effects/changes to the normal peak pressure conditions for EQ equipment qualification, based upon the comparison between the normal pre-EPU and post-EPU conditions. Accident peak pressure results postulated for Main Steam line breaks were compared to the initial qualification pressures, in a manner similar to the corresponding Main Steam line break temperatures (as noted by Item 5 below).

3. Normal Temperature Inside and Outside Containment:

   The EPU does not change the normal temperature conditions inside or outside the Containment. There is no change to the qualified life of the equipment.

4. Accident Temperatures Inside Containment:

   LAR No. 317 (BVPS-1) discuss the qualification of the equipment for the revised accident temperature profiles and the PAOT temperatures at the combined CC, EPU, and RSG (BVPS-1 only) conditions. The equipment was demonstrated to be qualified by comparing their accident tests to the containment accident temperature profiles, and met the required PAOTs with margin.

5. Accident Temperatures Outside Containment:

   The only impacts on accident temperatures outside the Containment are due to the Main Steam line breaks. The Main Steam line breaks in the Main Steam Valve House and Service Building were evaluated for BVPS-1 for the EPU conditions. The evaluations for BVPS-1 (LAR 317) demonstrate that the equipment is either not required to mitigate the effects of the accidents or have performed the intended safety function prior to exposure to accident peak temperatures. In addition, the evaluation demonstrated that the equipment will remain in the safe position during continued exposure to the accident conditions.

6. Normal and Accident Radiation Inside Containment:

   The Total Integrated Dose (TID) for the combined CC, EPU, and RSG (BVPS-1 only) conditions is discussed in Section 5.11. The EQ equipment in the Containment has been evaluated at the revised TID. The evaluation results indicate all the BVPS-1 EQ equipment inside Containment meets the post-EPU accident dose requirements when the scaling factor is applied to the current accident TID requirement (with reduction as applicable for beta shielding and/or installed configuration details).

7. Normal and Accident Radiation Outside Containment:

   The evaluation results for BVPS-1 indicate that all equipment meets the scaled TID values, based upon either the existing qualification, refined radiation calculation/assessments, or by evaluation of accident operational requirements.

8. Normal and Accident Humidity Inside and Outside Containment:

   As noted in Section 10.10.3 above, no changes to the normal and accident humidity conditions occur as a result of EPU operation.

10.10.5 Conclusions

Post-EPU qualification of EQ equipment was confirmed for the following required conditions:

- BVPS-1 EQ equipment is qualified for the revised environmental conditions for the combined CC, EPU, and RSG (BVPS-1 only) Loss of Coolant Accidents (LOCAs)/Main Steam Line Breaks (MSLBs) inside the Containment.
- BVPS-1 equipment is qualified to the extent necessary to respond to accidents inside the Main Steam Valve Houses and Service Buildings at the combined CC, EPU, and RSG (BVPS-1 only) accident conditions.
- BVPS-1 EQ equipment is qualified to the appropriate total integrated doses (TIDs) postulated for normal and accident conditions at increased reactor core power.

BVPS-1 EQ Program documentation will incorporate modified qualification parameters and equipment qualification conditions as part of the EPU implementation process.

10.11 SEISMIC AND DYNAMIC QUALIFICATION OF MECHANICAL AND ELECTRICAL EQUIPMENT (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.12 FLOOD PROTECTION (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.13 INTERNALLY GENERATED MISSILES INSIDE AND OUTSIDE CONTAINMENT (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.14 PROTECTIVE COATING SYSTEMS (PAINTS) – ORGANIC MATERIALS (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.15 STATION PROCEDURES/TRAINING (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

10.16 IMPACT ON PLANT RISK (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

11 ENVIRONMENTAL IMPACTS REVIEW (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

12 FINANCIAL ASSURANCE FOR DECOMMISSIONING (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

13 TESTING (EPU SECTION)

(This section number is included to maintain numbering consistency with the EPU Licensing Report. The information in this section is not applicable for the RSG Licensing Report.)

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Beaver Valley Power Station Unit 1 Replacement Steam Generator Component Report

Westinghouse

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Beaver Valley Power Station Unit 1 Replacement Steam Generator Component Report

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April 2005

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LIST OF ACRONYMS

AFW	Auxiliary Feedwater
ALARA	As Low As Reasonably Achievable
ANS	American Nuclear Society
ANSI	American Nuclear Society Institute
ASME	American Society of Mechanical Engineers
AVB	Anti-Vibration Bar
AVT	All Volatile Treatment
BTP	Branch Technical Position
BVPS	Beaver Valley Power Station
CFR	Code of Federal Regulations
CG	Center of Gravity
CL	Cold Leg
DBA	Design Basis Accident
DBE	Design Basis Earthquake
ECT	Eddy Current Testing
ENSA	Equipos Nucleares, S.A.
EPRI	Electric Power Research Institute
EPU	Extended Power Uprate
EQ	Equipment Qualification
ESF	Engineered Safeguards Features
ET	Eddy Current
°F	Degrees Fahrenheit
FENOC	FirstEnergy Nuclear Operating Company
FLB	Feedline Break
Ft	Feet
GDC	General Design Criteria
GL	Generic Letter
GPM	Gallons Per Minute
HFP	Hot Full Power
HZP	Hot Zero Power
ID	Inside Diameter
ISI	Inservice Inspection Program
IST	Inservice Testing Program
LAR	License Amendment Request
LOCA	Loss of Coolant Accident

LIST OF ACRONYMS (Continued)

MA	Mill Annealed
MBTU/hr	Millions of British Thermal Units per Hour
MFW	Main Feedwater
MSLB	Main Steamline Break
MSS	Main Steam System
MT	Magnetic particle
MWt	Megawatts thermal
NDE	Nondestructive Examination
NRC	Nuclear Regulatory Commission
NRS	Narrow Range Span
NSSS	Nuclear Steam Supply Systems
NWL	Normal Indicated Water Level
OBE	Operating Basis Earthquake
OD	Outside Diameter
ODSCC	Outside Diameter Stress Corrosion Cracking
OL	Operating License
OSG	Original Steam Generator
PCWG	Power Capability Working Group
PSI	Pound per Square Inch
PSI	Preservice Inspection
PSIA	Pounds per Square Inch – Absolute
PSIG	Pounds per Square Inch – Gauge
PT	Liquid (Dye) Penetrant
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
QA	Quality Assurance
RCS	Reactor Coolant System
RG	Regulatory Guide
RSG	Replacement Steam Generator
RSR	Relative Stability Ratio
RT	Radiographic
RTP	Rated Thermal Power
RTS/ESFAS	Reactor Trip System/Engineered Safety Features Actuation System
SCC	Stress Corrosion Cracking
SECY	Commission Papers
SER	Safety Evaluation Report
SG	Steam Generator
SGBS	Steam Generator Blowdown System

LIST OF ACRONYMS (Continued)

SGTP	Steam Generator Tube Plugging
SGTR	Steam Generator Tube Rupture
SGWH	Steam Generator Water Hammer
SLB	Steam Line Break
SRP	Standard Review Plan
SS	Stainless Steel
SSE	Safe Shutdown Earthquake
T_{avg}	Temperature Average
TDF	Thermal Design Flow
TS	Technical Specifications
TSP	Tube Support Plate
TT	Thermally Treated
TW	Tube Wear
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic
WCAP	Westinghouse Commercial Atomic Power

INTRODUCTION

This BVPS-1 RSG Component Report complements the BVPS-1 RSG Licensing Report (Enclosure 2 of BVPS-1 RSG LAR No. 320) by providing additional information regarding the BVPS-1 Model 54F replacement steam generator (RSG) components. The BVPS-1 RSG Licensing Report contains those portions of the Extended Power Uprate (EPU) Licensing Report that provide the technical justification for the Technical Specification and analysis methodology changes contained in BVPS-1 RSG LAR No. 320. As such, the BVPS-1 RSG Licensing Report contains Section 4.7.1 (BVPS-1 Replacement Steam Generators) of the EPU Licensing Report, which provides only a brief qualitative description of the BVPS-1 Model 54F RSG components since licensing acceptability of the RSG components is being addressed under the provisions of 10 CFR 50.59.

The BVPS-1 RSG Component Report has been developed to provide additional information for the BVPS-1 Model 54F RSGs, including design features, design bases, design codes and standards, design parameters, design transients, design evaluations, and quality assurance (tests and inspections). Where appropriate, these sections include comparison information for the BVPS-1 Model 51 original steam generator (OSG) components. The information provided in these sections demonstrates that the Model 54F RSG satisfies the applicable component design, analysis, and licensing requirements and is an acceptable replacement for the Model 51 OSG.

To promote consistency with the BVPS-1 RSG Licensing Report, the BVPS-1 RSG Component Report uses the same basic format and numbering convention as the BVPS-1 RSG Licensing Report. Section number 4.7 is used in this report to present the additional information for the BVPS-1 RSG components.

4.7 REPLACEMENT STEAM GENERATORS

4.7.1 Introduction

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

The BVPS-1 Model 54F RSG design is based on the Westinghouse Model F type steam generator. This steam generator design has been in operation since 1980 and has accumulated an extensive and superlative operating experience base. Currently there are more than 100 Model F type steam generators in service with over 1,220 cumulative steam generator years of operation.

The BVPS-1 Model 54F RSGs are manufactured by Equipos Nucleares, S.A. (ENSA). ENSA was organized in 1973 to manufacture nuclear power plant primary components. Since inception, ENSA has manufactured 10 reactor pressure vessels, 6 pressurizers, 4 sets of reactor internals, and 70 steam generators including those currently on order.

In collaboration with Westinghouse, ENSA has manufactured, or is currently manufacturing, 25 Westinghouse designed RSGs. Included in this number are 6 Model 54F RSGs (manufactured for the Farley Nuclear Plant Units 1 and 2) that are very similar in design to the Beaver Valley Model 54F RSGs. ENSA has demonstrated the capability to satisfactorily manufacture RSGs to Westinghouse design requirements.

When compared to the BVPS-1 Model 51 OSG design, the BVPS-1 Model 54F RSG design incorporates numerous design enhancements. The following summarizes the more significant design enhancements:

1. Thermally treated (TT) Alloy 690 (UNS N06690) tubing, which provides much improved resistance to stress corrosion cracking.

2. Enhanced anti-vibration bar (AVB) design, which provides for a more stable tube bundle and limits potential for both wear and high cycle fatigue of tubes.

3. Corrosion resistant tube support plate material (Type 405 stainless steel), which limits the potential for corrosion product buildup in the tube-to-tube support plate contact area.

4. Structural quatrefoil holes in the tube support plates, which improve axial flow within the tube bundle and minimize tube-to-tube support plate contact area.

5. Elevated feedring design, which minimizes the potential for thermal stratification and water hammer.

6. Addition of two instrument taps for steam flow measurement, which eliminates the potential for sharing of taps and the associated potential for interactions with water level measurement.

7. Increased number and types of external shell penetrations, which provide improved access to the secondary side tube bundle for sludge and foreign object removal.

8. Addition of a sludge collector in the secondary side flow recirculating loop, which provides a passive means for reducing the amount of sludge contained in the secondary side flow, resulting in a reduction in the rate of sludge deposition within the tube bundle and, thus, enhancing steam generator reliability and performance.

9. Improved first stage (primary) and second stage (secondary) moisture separators, which increases the design limit for minimum steam quality to 99.90% (i.e., reduces moisture carryover to 0.10% or less).

10. Addition of a flow distribution baffle above the tubesheet, which promotes flow conditions on the secondary side of the tubesheet that minimize the size of the zone where sludge deposition might occur.

11. Enlarged narrow range span (NRS) for steam generator water level control, which provides additional operating margin between the nominal level control setpoint and the low-low level trip setpoint.

12. Steam nozzle with an integral flow restrictor, which limits the potential main steamline break size and the associated loads on the steam generator internals and mass and energy releases inside containment.

13. Forged secondary side elliptical head pressure boundary component with an integral steam nozzle, which eliminates the nozzle to head weld.

14. Forged secondary side shell and transition cone pressure boundary components, which eliminate all longitudinal weld seams.

The following sections describe the Model 54F RSG design, including design features, design bases, design codes and standards, design parameters, design transients, design analyses, design evaluations, and quality assurance (tests and inspections). Where appropriate, these sections also include comparison information for the Model 51 OSG. The information provided in these sections demonstrates that the Model 54F RSG satisfies the applicable component design, analysis and licensing requirements and is an acceptable replacement for the Model 51 OSG.

4.7.2 Design Description

4.7.2.1 General

The RSG is of the unitized vertical type. It consists of a "shell and inverted U-tube" evaporator together with moisture separation equipment. The shell of the vessel is oriented with its axis vertical with the primary and secondary moisture separation equipment located in the upper part of the shell above the tube bundle. The primary side inlet and outlet nozzles are located in the bottom closure head and the steam

nozzle in the upper closure head. In addition, the vessel is equipped with nozzles for feedwater, blowdown, and drain piping connections.

The vessel is equipped with pipe sockets for instrument connections. Access to the primary side of the tubes and tube plate (also referred to as the tubesheet) is achieved through two manway openings provided in the bottom closure head. Two manways are located in the upper shell to provide access for inspection and maintenance of the steam drum internals. Six secondary handhole closures and two smaller inspection port openings provide access for conducting maintenance and inspection operations in the tube bundle.

Table 4.7-1 provides RSG design data corresponding to the design data presented in Table 4.1-5, Steam Generator Design Data, of the BVPS-1 Updated Final Safety Analysis Report (UFSAR) (Reference 1). Table 4.7-2 provides additional information for RSG key design features. For comparison purposes, Tables 4.7-1 and 4.7-2 also include corresponding OSG design data and key design features. A schematic of the RSG is shown in Figure 4.7-1.

4.7.2.2 Function

The RSG uses 3,592 U-tubes of 0.875 inch outside diameter (OD) and 0.050 inch wall. Total heat transfer area is approximately 54,500 square feet. Heat is transferred from the single phase pressurized water on the primary side to subcooled water and saturated steam/water mixture flowing axially up the tube bundle on the secondary side.

The primary side pressure boundary is comprised of the steam generator channel head, tube plate and tube bundle. Primary fluid enters the 31-inch inside diameter (ID) inlet nozzle in the hemispherical channel head. The channel head is divided into inlet (hot leg) and outlet (cold leg) plenums by a central divider plate. The primary fluid enters the U-tubes, which are flush welded to the Alloy 690 cladding on the tube plate primary side and hydraulically expanded into the tube plate tube holes. The primary fluid cools as it flows through the U-tubes and exits into the channel head outlet plenum, where it leaves the steam generator though the 31-inch ID outlet nozzle.

The secondary side pressure boundary is comprised of the tube plate, tube bundle, lower shell barrels, shell transition cone, upper shell barrels and elliptical head. Because it is a recirculating steam generator design, the Model 54F secondary side is divided into downcomer and riser regions. The downcomer region is composed of the annular region inside the secondary shell and outside the tube bundle wrapper, and the water-filled region outside of the primary moisture separators. It extends up to the downcomer water level. Similarly, the riser region is defined as the region inside of the tube bundle wrapper and inside the primary moisture separators.

During normal operation, the feedwater enters the steam generator through a spray nozzle-equipped feedring located in the steam generator upper shell. The feedring is elevated above the feedwater nozzle to minimize the potential for feedwater thermal stratification at the nozzle location. The spray nozzles feature a top mounted (vented) configuration for water hammer mitigation with small diameter holes to inhibit loose parts ingress into the steam generator.

Incoming feedwater mixes with saturated water that has been stripped from the tube bundle outlet flow by the primary and secondary separators. The result is subcooled water in the steam generator downcomer region. This water flows down the annulus between the tube bundle wrapper and shell and enters the tube bundle region via the opening at the bottom of the wrapper just above the tube plate. The flow then turns and flows upward along the tube bundle U-tubes.

As it flows upward, the fluid on the secondary side is heated by the primary side fluid via heat transfer through the U-tube walls. The secondary side fluid boils and becomes a mixture of saturated liquid and steam. This saturated mixture continues to flow upward into the moisture separator assembly.

The two-phase flow leaving the tube bundle enters the primary moisture separator assembly, which is comprised of sixteen 19.5-inch ID risers with integral swirl vanes. The swirl vanes impart a centrifugal acceleration to the flow, causing the heaver liquid portion to collect along the riser pipe ID. This liquid flow is returned to the steam generator downcomer plenum through the gap between the top of the riser pipe and the bottom of the orifice ring.

A relatively high quality steam-water mixture flows upward through the primary separator orifice ring. Additional separation takes place by gravity as the flow travels upward to the entrance of the single tier secondary separator. The secondary separator contains six banks of double pocket vanes that subject the flow to multiple changes in direction. These changes in flow direction produce flow accelerations that act to separate out the remaining liquid in the steam-water mixture. The liquid then flows down the vanes to drainage troughs and is returned to the downcomer plenum via multiple drain pipes. The steam flow exiting the secondary separators then leaves the steam generator through the steam outlet nozzle.

All saturated water separated from the steam-water mixture is directed to the steam generator upper downcomer plenum. Here it mixes with incoming subcooled feedwater, completing the recirculation loop.

4.7.2.3 Design Features

The RSG design includes a number of key design features that serve to enhance steam generator operation, performance and maintenance. The RSG design features and materials have been developed and selected to minimize the potential for tube degradation. The design features enhance steam and water flow by the tubes, which minimizes the potential for concentration of chemical species that can be detrimental to tubing material.

The U-tubes are fabricated of nickel-chromium-iron (Ni-Cr-Fe) Alloy 690. The tubes undergo thermal treatment following tube-forming and annealing operations. The thermal treatment subjects the tubes to elevated temperatures for a prescribed period of time to improve the microstructure of the material. Thermally treated Alloy 690 has been shown in laboratory tests and operating nuclear power plants (Reference 2) to be very resistant to primary water stress corrosion cracking (PWSCC) and outside diameter stress corrosion cracking (ODSCC). The use of Alloy 690 does not require changes to primary or secondary water chemistry requirements or procedures. The water chemistry specifications for BVPS-1 found in UFSAR Tables 4.2-2 and 4.2-3 are consistent with industry guidelines (Reference 3) that have been developed to minimize the potential for corrosion of nickel-chromium-iron alloys.

The RSG design minimizes crevices between the tubes and the tubesheet and contact areas between the tubes and the tube support plates. All tubes are expanded into the tubesheet for the full depth of the tube hole by the hydraulic expansion process. This process has the advantages of expanding the tube into essentially metal-to-metal contact with the tube hole without excessively cold working the tube wall, as might be done with other expansion processes such as mechanical rolling. The hydraulic expansion process provides precise dimensional control. Strict tolerances and other quality control measures are applied to the hydraulic expansion process to make sure that the tubes are expanded essentially over the full depth of the tubesheet.

Tube support plates of the flat-contact broached quatrefoil hole configuration are used to support the tubes. The tube support plates are sized to provide sufficient strength that the tubes meet the applicable structural criteria during seismic loading. The clearance between the tube and tube support and the spacing between the supports is sized to minimize the potential for excessive vibration of the tubes. The tube support plates are made of corrosion resistant Type 405 stainless steel (Type 405 SS). The tube hole design reduces the tube-to-tube support plate contact area while providing for maximum steam and water flow in the open areas adjacent to the tube. The flat land contact provides additional dryout margin.

The channel head is a low alloy steel forging with stainless steel cladding. The tubesheet is low alloy steel with the reactor coolant side clad with Alloy 690. The tube-to-tubesheet joint is welded to the cladding on the primary side. The divider plate is thermally treated Alloy 690. No Alloy 600 material is used on the reactor coolant side.

Three anti-vibration bars (AVBs) are installed in the U-bend portion of the tube bundle to minimize the potential for excessive vibration. The anti-vibration bars are fabricated of Type 405 stainless steel. The construction minimizes the gaps between the anti-vibration bars and tubes.

The following sections summarize the more significant key design features.

4.7.2.3.1 Tube Bundle and Tubes

The RSG tube bundle is sized to provide a larger heat transfer area (i.e., more tubes with smaller tube pitch) than the original steam generators while maintaining essentially the same primary coolant flow. In this way, the tube bundle design supports primary coolant forced circulation flow and natural circulation flow, where the tube bundle provides the thermal driving head.

The RSG tube bundle contains 3,592 tubes with an outside diameter (OD) of 7/8-inch (0.875-inch). The tube pitch is square with a pitch of 1.225 inches. The tube bundle total heat transfer area is approximately 54,500 ft^2.

For comparison, the OSG tube bundle contains 3,388 tubes with an OD of 7/8-inch, tube pitch (square) of 1.281 inches, and total heat transfer area of approximately 51,500 ft^2.

4.7.2.3.2 Tube Material

The RSG tube material is thermally treated SB-163 Alloy 690 (i.e., Alloy 690 TT). Alloy 690 TT has been under development since the early 1970s and, based on extensive industry-wide test programs, has

been determined to be the material of choice for steam generator applications. Alloy 690 TT has been shown through both laboratory testing and operational experience (Reference 2) to provide enhanced corrosion resistance compared to previous materials (e.g., Alloy 600) with regard to primary water stress corrosion cracking (PWSCC) and outer diameter stress corrosion cracking (ODSCC). No steam generator tube degradation due to stress corrosion cracking has been observed in Westinghouse steam generators using Alloy 690 TT tube material.

For comparison, the OSG tube material is Alloy 600.

4.7.2.3.3 Tube-to-Tubesheet Joint

The RSG tube-to-tubesheet joint provides the structural barrier between the primary and secondary sides of the steam generator. The RSG tubes are hydraulically expanded full depth through the thickness of the tubesheet to minimize the tube-to-tubesheet crevice while locating the transition as close as practical to the top of the tubesheet. Tubesheet thickness is measured to accurately adjust the hydraulically expanded distance. The hydraulic expansion process is preferred to other techniques, such as the mechanical roll or explosive expansion processes, based on the analysis of test results and experience.

For comparison, the OSG tube-to-tubesheet joint used the mechanical roll process.

4.7.2.3.4 Tube Support Plates/Flow Distribution Baffle

Seven tube support plates of the flat-contact broached quatrefoil hole configuration and one flow distribution baffle of the flat-contact broached octafoil hole configuration are used in the RSG. All tube supports are made of SA-240 Type 405 SS. The broached tube hole configuration reduces the tube-to-tube support plate contact area while providing for maximum steam/water flow in the open areas adjacent to the tube. Flat tube contact geometry in the RSG provides additional dryout margin. The flow distribution baffle promotes flow conditions on the secondary side of the tubesheet that minimize the size of the zone where sludge deposition might occur. Materials are selected to prevent the potential for tube denting due to tube support plate corrosion.

For comparison, the OSG uses seven tube support plates made of carbon steel with a round tube hole design. The OSG does not have a flow distribution baffle.

4.7.2.3.5 U-Bend Supports

Three sets of SA-479 Type 405 SS anti-vibration bars (AVBs) are assembled in the RSG U-bend region of the tubes to provide support in the areas potentially susceptible to degradation due to U-bend vibration and wear. The dimensional variability (i.e., ovality) of the RSG tubes in the U-bend region is strictly controlled during the manufacturing process. The thickness of the three sets of U-bend AVBs is also tightly controlled. The three sets of AVBs in the U-bend provide redundancy so that all the tubes remain fluidelastically stable even if it is assumed that some of the support points are inactive. The AVBs in adjacent columns are inserted to different depths to minimize the U-bend pressure drop and to discourage the formation of flow stagnation regions. The AVBs are nearly perpendicular to the centerline of the tubes at all locations in the U-bend so as to provide support without unnecessary tube contact. These

features of the U-bend support system provide significant margin against flow stagnation, corrosion and tube vibration.

For comparison, the OSG uses two sets of AVBs made of Alloy 600 material.

4.7.2.3.6 Tubesheet and Channel Head

The RSG tubesheet is a single piece forging with integral weld preps. Its thickness including clad is 21.425 inches. The tubesheet is constructed from a SA-508 Class 3a forging and the surface area exposed to reactor coolant is clad with weld deposited Alloy 690 with a maximum cobalt content of 0.10%. The channel head is also a single forging constructed from a SA-508 Class 3 forging with integral nozzles. The channel head surface area exposed to reactor coolant is clad with weld deposited stainless steel with a maximum cobalt content of 0.10%. The divider plate is Alloy 690 with a maximum cobalt content of 0.05%.

For comparison, the OSG tubesheet including cladding is 21.1875 inches thick. The tubesheet and the channel head surface areas that are exposed to reactor coolant are clad with weld deposited Alloy 600 and stainless steel, respectively, with a maximum cobalt content of 0.20%.

4.7.2.3.7 Access and Maintenance Provisions

The RSG has two 16-inch inside diameter (ID) manways on both the primary and secondary sides. The RSG secondary side also has six 6-inch ID handholes (four handholes located above the tubesheet and two handholes located above the flow distribution baffle) and two 4-inch ID inspection ports (located above the top tube support plate in the U-bend region). These openings are located to maximize their utility for inspection and maintenance of the tubesheet and tube bundle

Studs with nuts and spherical washers secure the gasket and cover of the RSG secondary side manways. The RSG secondary side manways provide access to the steam drum internals from the main steam nozzle down to and including the top of the tube bundle. The RSG primary side manways provide access to the bottom face of the tubesheet and the inside of the tubes.

For comparison, the OSG has two 16-inch ID manways on both the primary and secondary sides and two 6-inch ID handholes above the tubesheet on the secondary side.

4.7.2.3.8 Water Level Control (Narrow Range) Span

The RSG water level control (narrow range) span is 212 inches. This is achieved by locating the lower narrow range level taps in the shell transition cone and the upper narrow range level taps in the top of the upper shell. The normal indicated water level for full-load operation is 513 inches above the top of the tubesheet, corresponding to approximately 65% narrow range span (NRS). These tap locations and large narrow range span maximize operating margin for the low-low level reactor trip and AFW actuation setpoint while providing acceptable margin for the high-high level turbine trip and feedwater isolation actuation setpoint during normal operation and operational transients.

The RSG incorporates several design enhancements that minimize water level measurement uncertainties and maximize water level operating margins, while using proven design features to meet moisture carryover limits at the design power level. This is accomplished by providing a large water level control (narrow range) span and by minimizing the internal pressure drops due to steam flow in the water level control span. Relative to the standard Model F type steam generator, the RSG has enlarged Mid-Deck Plate and Intermediate Deck Plate open areas, resulting in reduced pressure drops across these plates. The feedwater ring is located interior to the outer circle of primary separators and sufficiently away from the level taps that the feedwater ring and supports do not introduce any measurable pressure drop. The Intermediate Deck Plate also incorporates vent pipes for additional relief of potential steam carryunder bubbles. The effect of internal pressure drops and steam carryunder are addressed in the analyses that establish the water level control and trip setpoints for the water level control (narrow range) instrumentation.

For comparison, the OSG water level control span is 144 inches with the lower level tap located near the bottom of the upper shell. The OSG normal indicated water level for full-load operation is 505.9 inches above the top of the tubesheet, corresponding to approximately 44% NRS.

4.7.2.3.9 Physical Interfaces

The RSG conforms to the OSG physical interfaces (i.e., attached piping and supports). The reactor coolant inlet and outlet nozzles, steam nozzle, and feedwater nozzle have the same position as the OSG. The overall height of the RSG is approximately 813 inches, which includes a small increase in steam nozzle length to accommodate installation field fit-up. Likewise, the feedwater nozzle external length is increased slightly to improve fit-up. The outside diameters of the RSG upper shell and lower shell are 176.92 inches and 135.5 inches, respectively, which are essentially the same as the OSG. The RSG reactor coolant inlet and outlet nozzles contain nozzle dam closure rings for the installation of nozzle dams during tube inspection and maintenance operations. To support plant drain down operations to install the nozzle dams, the nozzle dam closure rings are designed to establish nozzle spillover points that are essentially the same as the OSG.

The number and orientation of the RSG nozzles is the same as for the OSG with the following exceptions:

1. The RSG and the OSG each have three narrow range level instruments, each with upper and lower narrow range level taps. The location of the upper level taps is the same, however, the location of the lower level taps has been changed on the RSG to enlarge the narrow range level span to 212 inches.

2. The RSG has two instrument taps for steam flow measurement located at the same elevation as the upper narrow range level taps, however, the instrument taps will be plugged. The OSG has one instrument tap for steam flow measurement, however, it is plugged.

   Steam flow measurement with the OSGs is accomplished by inline flow measurement venturis located in the main steam lines. This method of steam flow measurement will be retained following steam generator replacement. Since the RSG design incorporates main steam nozzle flow restrictors, the pressure loss across the main steam nozzle could be used for steam flow measurement. To support this option, the RSG design includes two separate taps for steam flow

measurement. Separate taps eliminate the need for sharing of taps with steam generator water level, and the potential for interaction between the steam flow and water level measurement instrumentation functions. The RSG design meets the separation requirements of industry standard Institute of Electrical and Electronics Engineers (IEEE)-603 (Reference 4) and eliminates the potential for sharing of taps and the associated potential for interaction between the steam flow and water level measurement instrumentation functions.

For comparison, the OSG overall height is 812 inches and the outside diameter of the upper and lower shell are 175.75 inches and 135.0 inches, respectively.

4.7.2.3.10 Blowdown and Sludge Removal

Steam generator blowdown is used to remove a portion of the secondary side bulk fluid, aiding in secondary side chemistry control and particulate removal. The RSG design includes an internal perforated pipe located on the shell side of the tubesheet in the tube lane and connected internally to two 2-inch blowdown nozzles located on the lower shell at the tubesheet elevation. The internal perforated pipe promotes effective sludge removal during blowdown operations.

The blowdown nozzles are connected to the blowdown system. The RSG is designed for a maximum continuous blowdown flow rate of 1% of feedwater flow at full power conditions, which corresponds to approximately 44,000 lb/hr. Higher blowdown rates up to a maximum of 3% of feedwater flow at full power conditions are acceptable for short periods.

For comparison, the OSG design includes an internal perforated pipe connected to two 2-inch blowdown nozzles on the lower shell at the tubesheet elevation.

4.7.2.3.11 Sludge Collector

The RSG tube bundle is designed to minimize the potential effects of secondary side particulates (sludge); however, sludge ingress is primarily governed by the plant operation practices. To assist in the collection and removal of sludge, the RSG incorporates a sludge collector, which is a passive sludge collecting feature in the secondary side flow recirculating loop. This sludge collector is located in the center of the upper shell at the base of the primary moisture separators. Water passing through the tube bundle is separated by the primary and secondary moisture separators and is directed back to the tube bundle. As the water leaves the separators, a portion of it passes through the sludge collector, which provides a settling zone for the suspended solids. As long as there is recirculating flow within the steam generator, the sludge collector is actively removing suspended solids. In developmental testing and from operating experience on other plants, the sludge collector has been found to reduce both the suspended solids and the amount of sludge deposited on the tubesheet. The sludge collector is a passive device which requires no operator actions and has no operational requirements. It has built-in cleaning jets and suction ports for use during normal maintenance to remove the sludge from the sludge collector.

For comparison, the OSG does not have a comparable sludge collecting feature.

4.7.2.3.12 Feedwater Nozzle and Feedring

Feedwater is introduced into the RSG through a feedwater nozzle located in the RSG upper shell. The nozzle does not require a flow-limiting device because the feedring itself provides this function. The nozzle contains a welded thermal liner which minimizes the impact of rapid feedwater temperature transients on the nozzle. The feedwater distribution ring is welded to the feedwater nozzle to minimize the potential for draining the ring. The feedring is located above the elevation of the feed nozzle to minimize the time required to fill the feed nozzle during a cold water addition transient. The feedwater is discharged through spray nozzles installed on the top of the ring. These features reduce the thermal fatigue loading on the feedwater nozzle, eliminate steady state thermal stratification in the feedwater nozzle and feedwater piping elbow at the feedwater nozzle entrance, and minimize the potential for bubble collapse water hammer in the feedwater distribution ring. The feedwater piping elbow at the feedwater nozzle entrance also contains an elbow thermal liner that minimizes the effects of thermal stratification on the elbow to nozzle weld and the weld of the feedwater inlet thermal sleeve to feedwater nozzle.

The RSG feedring is fabricated from alloy steel with a significant chromium content to provide enhanced erosion/corrosion resistance characteristics. The feedring has spray nozzles that are spaced around the feedring circumference to distribute the feedwater into the upper shell recirculating water pool.

For comparison, the OSG feedring is located at the same elevation as the feedwater inlet nozzle, making the feedring and nozzle susceptible to steady state thermal stratification and potential water hammer, and the OSG feedring is made of carbon steel, which is less resistant to erosion/corrosion.

4.7.2.3.13 Moisture Separators

The RSG moisture separation features include first stage (primary) and second stage (secondary) moisture separators. The RSG includes an elliptical upper head, which accommodates the moisture separation features and provides space for access and maintenance.

The RSG is designed to provide steam to the secondary system with moisture carryover limited to less than or equal to 0.10% during steady state operation with water at the normal control level. This design limit applies to full-load operation at the EPU design NSSS thermal power level of 2910 MWt (970 MWt/RSG).

For comparison, the OSG moisture carryover design limit is less than or equal to 0.25% for full-load operation at the original design NSSS thermal power level of 2660 MWt (886.7 MWt/OSG).

1. Primary Moisture Separators

   The RSG design includes sixteen 19.5-inch ID primary moisture separators of the centrifugal with low pressure drop design type, each supported by a lower deck plate. The RSG primary separators use field proven swirl vane, riser, and outlet orifice design features.

   For comparison, the OSG design includes three 56-inch ID primary separators of the centrifugal type.

2. Secondary Moisture Separators

The RSG secondary separators consist of six single-tier dryer banks (approximately 215 ft^2 face area) arrayed parallel to each other and spaced across the upper portion of the steam drum. The RSG single-tier dryer bank spacing and the total length of the banks provides enhanced moisture separating capacity. Steam generator moisture separation performance is further enhanced through the use of double pocket high capacity dryer vanes. Drain pipes located at the ends of each secondary separator dryer bank carry captured water downward into the recirculating pool.

For comparison, the OSG design consists of eight two-tier dryer banks (approximately 179 ft^2 face area).

The RSG primary and secondary moisture separator components are sized, designed, and proven using laboratory testing and field experience.

4.7.2.3.14 Main Steam Nozzle Flow Restrictor

The RSG main steam nozzle incorporates a steam nozzle flow-limiting device (restrictor), consisting of seven 6.03-inch ID venturis installed into integral holes in the steam outlet nozzle. The flow area of the RSG steam nozzle flow restrictor is 1.388 ft^2. The flow restrictor limits the rate of energy release into containment during a postulated steamline break, thereby limiting the loads on the steam generator internals during such an event. The venturis are secured to the steam outlet nozzle by welding the venturi ends to the steam nozzle.

For comparison, the OSG design does not include an integral steam nozzle flow restrictor. The OSG steam nozzle flow area is 4.6 ft^2.

4.7.2.3.15 Upper Shell-Mounted Platform

A field-installable platform is attached to the exterior of the secondary side upper shell to provide access to the RSG secondary manways and instrumentation lines for maintenance. The platform extends approximately 270° around the upper shell and is approximately 36 inches in width. Ladders are provided with the platform to extend to the top of a nearby cubicle wall.

For comparison, the OSG does not have a comparable platform mounted on the upper shell.

4.7.3 Design Bases

RSG design data are given in Table 4.7-1. The ASME Code Sections used for the RSG design are presented in Section 4.7.4. The design parameters (normal operating conditions) and the design transients (transient operating conditions) for the RSG design are presented in Sections 4.7.5 and 4.7.6, respectively. The combined loading conditions and design stress and fatigue limits are addressed in Section 4.7.7.2.

The RSG is designed to perform the same design functions as the OSG, including the following:

1. Transfer the heat generated in the Reactor Coolant System (RCS) to the secondary system.

2. Provide the steam flow required at full power operation to the secondary system at the design flow rate with a moisture content less than the design limit.

   The RSG moisture separation equipment is designed to limit moisture carryover so that it does not exceed 0.10% by weight at steady-state 100% full-load steam flow, whereas the OSG is designed to limit moisture carryover so that it does not exceed 0.25% by weight at steady-state 100% full-load steam flow.

3. Provide a boundary for containing the reactor coolant under operating temperature and pressure conditions to confine radioactive material and limit to acceptable values uncontrolled release to the secondary system and to other parts of the unit under conditions of either normal or abnormal reactor behavior.

The RSG materials are selected to be compatible with specified primary and secondary side water chemistry to minimize corrosion of surfaces exposed to primary side (reactor coolant) and secondary side water. The compatibility of RSG tubing with both primary and secondary coolants is discussed in Section 4.7.8.1.

The RSG is designed to minimize unacceptable damage from mechanical or flow induced vibration. Tube support design is discussed in Sections 4.7.7.3 and 4.7.8.5. The tubes and tubesheet are analyzed to show that they can withstand the applicable maximum accident loading conditions.

4.7.4 Design Codes and Standards

The RSG is designed and analyzed in accordance with the ASME Boiler and Pressure Vessel Code, (herein referred to as the ASME Code), Section III, 1989 Edition, no Addenda (Reference 5). The RSG primary side is classified as ASME Code Class 1; the RSG secondary side is classified as ASME Code Class 2. The design, analysis, material, fabrication, inspection, examination, and testing of RSG components and assemblies are in accordance with ASME Code Sections listed in Table 4.7-3.

The design codes and standards used for the RSG are, at a minimum, equivalent to the design codes and standards used for the OSG. The RSG ASME Code Design Report includes a reconciliation with respect to the ASME Code (Section III, 1965 Edition through Summer 1967 Addenda) used for the OSG.

4.7.5 Design Parameters

The RSG is designed and analyzed for the normal operating conditions associated with the Nuclear Steam Supply Systems (NSSS) power level of 2910 MWt (970 MWt/RSG). The associated design parameters are defined in the NSSS design (PCWG) parameters for 2910 MWt (NSSS power), as shown in Table 4.7-4. These design parameters incorporate design data for the RSGs.

In addition to the NSSS power level of 2910 MWt (970 MWt/RSG), these normal operating conditions include a full power reactor vessel average temperature range of 566.2° to 580°F, a full power feedwater temperature range of 400° to 455°F, and a steam generator tube plugging (SGTP) range of 0% to 22%.

4.7.6 Design Transients

The RSG is designed and analyzed for the transient operating conditions associated with the NSSS power level of 2910 MWt (970 MWt/RSG), including associated ranges for reactor vessel average temperature, feedwater temperature, and SGTP level.

Table 4.7-5 lists the NSSS design transients for the RSG, which establish the transient operating conditions for the RSG design and analyses.

4.7.7 Design Analyses

The RSGs are designed and analyzed in accordance with the ASME Code Sections presented in Section 4.7.4, the normal operating conditions presented in Section 4.7.5, and the transient operating conditions presented in Section 4.7.6. Analyses are performed in the major analytical areas of thermal-hydraulic performance, structural integrity, flow induced vibration and wear, and tube integrity (draft Regulatory Guide 1.121). This section summarizes the design analyses performed in these areas to show that the RSG is in compliance with design requirements and acceptance criteria. Also summarized in this section is the evaluation performed for the RSG feedwater inlet distribution system to show that it is in compliance with guidelines for the prevention and mitigation of water hammer.

4.7.7.1 Thermal-Hydraulic Performance

The RSG thermal-hydraulic performance is affected by the normal operating conditions (PCWG Parameters), including the ranges for reactor vessel average temperature, feedwater temperature, and SGTP level. At full power operation, the reactor vessel average temperature and SGTP level determine steam pressure. Steam flow at full power is affected by feedwater temperature. Thus, variations in these parameters within their defined ranges impact RSG thermal-hydraulic performance and affect secondary side steam pressure and steam flow. The full-load performance of the RSG, including secondary side steam pressure and steam flow, is included in Table 4.7-1 and Table 4.7-4. For comparison, Table 4.7-1 shows OSG full-load performance information.

The RSG is designed to enhance plant operation and performance by incorporating improved water level control features to maximize operability. The RSG is designed to operate from no-load to full-load with a constant water level program. The elevations at which the RSG water level narrow range span instrument taps are located establish a narrow range span of 212 inches. The normal indicated water level is located 513.0 inches above the top of the tubesheet, corresponding to 65% NRS. The low-low level and high-high level trip setpoints take into account level measurement uncertainties and provide enhanced operating margin to minimize challenges to the low-low level reactor trip and engineered safety features actuation setpoint while providing acceptable margin to the high-high level engineered safety features actuation setpoint.

The RSG is designed to operate with a full-load circulation ratio in the range of 3.3 to 3.6, depending on where reactor vessel average temperature, feedwater temperature and SGTP level are within their design ranges. The RSG secondary side masses will vary depending on the actual operating conditions. The RSG full-load performance data in Table 4.7-1 includes the ranges for secondary side water volume, steam volume and fluid heat content.

The thermal-hydraulic performance characteristics used to evaluate the acceptability of RSG operation at 2910 MWt (970 MWt/RSG) include secondary side thermal-hydraulic parameters (e.g., heat flux, steam flow, steam pressure, secondary side masses), moisture carryover, circulation ratio, hydrodynamic stability, and local (liquid) dryout on the tube wall (which addresses the combined effect of secondary side mass flow, heat flux, and pressure).

The thermal-hydraulic analyses performed to evaluate RSG performance over the design range of operating parameters showed that all thermal-hydraulic characteristics are acceptable, including the thermal-hydraulic performance parameters, moisture carryover, hydrodynamic stability, and local dryout on the tube walls. The thermal-hydraulic analyses for the RSG, including methodology, acceptance criteria and results, are documented in the RSG Thermal and Hydraulic Design Analysis Report, and are summarized in the following sections.

4.7.7.1.1 Thermal-Hydraulic Performance Parameters

The RSG thermal-hydraulic performance parameters are affected by NSSS power, reactor vessel average temperature, SGTP level, and feedwater temperature. The impact of reducing reactor vessel average temperature and/or increasing SGTP level within their analyzed ranges is to decrease RSG steam pressure. RSG steam flows decrease with reduced feedwater temperatures as a result of the increased enthalpy difference at full power. RSG steam pressure is not significantly affected by feedwater temperature. At a given power level, average heat fluxes are proportional to the reactor coolant inlet temperature and the tube heat transfer area in service and are not affected by feedwater temperature. Secondary side liquid mass increases with reduced feedwater temperature.

The RSG analyses showed that the thermal-hydraulic secondary side performance parameters (e.g., heat flux, steam flow, steam pressure, and secondary side masses) fall within acceptable ranges and satisfy design and acceptance criteria for operation at the NSSS power level of 2910 MWt (970 MWt/RSG).

4.7.7.1.2 Moisture Carryover

Moisture performance depends on steam flow, steam pressure, and water level. The amount of moisture carryover tends to increase as steam flow increases, as steam pressure decreases, or as water level increases.

The RSG analyses showed that moisture carryover satisfied the design limit of 0.10% for operation at the design 100% full-load steam flow rate, minimum RSG operating pressure, and normal RSG operating water level.

4.7.7.1.3 Circulation Ratio

Circulation Ratio decreases with increases in steam flow.

The RSG analyses showed that for the design range of full power steam flow, the circulation ratio would range from 3.3 to 3.6. This circulation ratio range is acceptable.

4.7.7.1.4 Hydrodynamic Stability

Hydrodynamic stability prevents steady-state oscillations in secondary side thermal-hydraulic parameters. The hydrodynamic stability of a steam generator is characterized by a damping factor. A negative value of this parameter indicates stable operation, and thus small perturbations of steam flow, steam pressure, or feedwater temperature will die out rather than grow in magnitude. This in turn promotes stable water level and control.

A number of factors impact hydrodynamic stability, including power level, steam pressure, and downcomer subcooling (due to feedwater temperature). The RSG analyses showed that for the design range of full power steam flow and feedwater temperature, the damping factors are substantially negative. Thus, the RSGs will remain hydrodynamically stable over the design range of operating parameters.

4.7.7.1.5 Local (Liquid) Dryout

Local (liquid) dryout of the tube wall results from liquid deficiency on the tube wall, and thus can produce concentration of chemicals and/or particulates. Dryout is a localized phenomenon due to several factors, such as circulation ratio, steam pressure, heat flux, steam flow rate, and secondary side water chemistry. The potential for dryout to occur tends to increase with higher power levels, higher heat fluxes, lower circulation ratios, lower steam pressures, and higher concentrations of certain particulates and contaminants.

The RSG analyses evaluated the relevant parameters. It showed that the potential for dryout to occur is greatest in the upper bundle at the U-bend. However, the analysis showed that even the U-bend has margin to local dryout. Thus, it is concluded that there is no concern for local dryout on the tube walls for RSG operation over the design range of operating parameters.

4.7.7.2 Structural Integrity

Structural analyses were performed in accordance with the ASME Code, Section III, 1989 Edition, no Addenda in order to demonstrate the structural integrity of the RSG components. The analyses evaluated the primary side components (including channel head, divider plate, primary nozzles, tubesheet, and tube-to-tubesheet weld) and the secondary side components (including the upper shell, shell transition cone, lower shell, junction of tubesheet and stub barrel, feedwater nozzles, secondary manway openings, handholes, inspection ports, and shell taps).

The RSG structural analyses (pressure boundary and internals) considered the following sources of loadings:

1. Deadweight
2. Primary system pressure
3. Secondary system pressure
4. Pipe nozzle loadings
5. Pipe rupture loadings
6. Seismic inertia and anchor movements
7. Operating Basis Earthquake (OBE)
8. Safe Shutdown Earthquake (SSE)
9. Flow loads (based on pressure, temperature and flow information)
10. Thermal loads (based on primary, steam and feedwater temperatures)
11. Upper Shell Platform loadings

Normal operating conditions (pressures, temperatures and flows) were obtained from the PCWG parameters as described in Section 4.7.5 and the transient operating conditions were obtained from the NSSS design transients as described in Section 4.7.6. The NSSS design transients include transient operating conditions for both the primary side (reactor coolant) and the secondary side. Loss-of-coolant primary pipe break hydraulic forcing functions were obtained from the LOCA hydraulic forces analysis for the RSG. OBE and SSE seismic response spectra, pipe rupture loadings, and pipe nozzle loadings were obtained from applicable design specifications and the reactor coolant loop analysis for the RSG.

The Design, Service and Test loadings for the ASME Code Design Condition, for the Level A and B (Normal and Upset) Conditions, for Level D (Faulted) Conditions, and for Test Conditions were developed in accordance with the ASME Code, Subsection NCA and Subsection NB. Service Limits were obtained from Subsection NB for the Design Conditions, for Service Level A and B, and for the Test Conditions. Level D service limits were obtained from Appendix F.

The RSG structural analyses used the following load combinations.

Loading Conditions	External Mechanical Loads(4)	Pressure and Thermal Loads
Design	Deadweight + Pressure + OBE(1)	Design Pressures and Temperatures
Normal (Level A)	Deadweight + Pressure + Thermal	Pressure and Thermal
Upset (Level B)	Deadweight + Pressure + Thermal	Pressure and Thermal
Upset (Level B)	Deadweight + Pressure + Thermal + OBE	Pressure and Thermal
Faulted (Level D)	Deadweight + Pressure(1)	Pressure and Thermal
Faulted (Level D)	Deadweight + Pressure + DBE(1)	Pressure and Thermal
Faulted (Level D)	Deadweight + Pressure + DBE + Pipe Rupture(1) (2) (3)	Pressure and Thermal
Test	Deadweight + Pressure	Pressure and Temperature

Notes:
(1) Inside the Code defined region of reinforcement, thermal pipe loads must be included in the analysis.
(2) Deadweight + Pressure + $[(|\text{Pipe Rupture}| - |\text{Pressure}|)^2 + (\text{DBE})^2]^{1/2}$.
(3) Pipe Rupture is either LOCA, Steamline Break, or Feedwater Line Break.
(4) Upper Shell Platform loadings must be included with external mechanical loads, as applicable.

Stress states due to applied loads were calculated using classical analytical methods or computer codes. The criteria used to determine acceptable stress states were obtained from the ASME Code.

The principal computer codes used in the dynamic and static analyses of the RSGs to determine mechanical loads, stresses, and deformations are the ANSYS and WECAN/Plus programs. These programs are general purpose finite element structural analysis computer codes that are used in the design and analysis of RSG components. ANSYS is a program that is available in the public domain and WECAN/Plus is a Westinghouse developed and verified computer program that is a successor to the WECAN (Westinghouse Electric Computer Code) computer code previously used in the design and analysis of other NSSS components as described in Section B.3.9 of the BVPS-1 UFSAR (Reference 1).

Structural analyses were performed for the following RSG components:

1. Primary Chamber, Tubesheet, Stub Barrel Complex
2. Primary Nozzles
3. Primary Manways
4. Primary Chamber Divider Plate
5. Tube/Tubesheet Weld
6. Tubes
7. Secondary Shell
8. Handhole
9. Inspection Port
10. Minor Shell Taps
11. Feedwater Nozzle and Thermal Sleeve
12. Secondary Manways

13. Steam Outlet Nozzle and Elliptical Head
14. Lower Internals
15. Upper Internals
16. Feedring, Feedring Supports, and Spray Nozzle
17. Upper Shell Platform
18. Feedwater Elbow Thermal Liner

The RSG structural analyses showed that all applicable requirements of the ASME Code are satisfied for the RSG components. The structural analyses for RSG components, including methodology, acceptance criteria and results (maximum stress range/allowable stress range and fatigue usage factors), are documented in the RSG ASME Code Design Report.

4.7.7.3 Flow Induced Vibration and Wear

Analyses were performed to evaluate the RSG tube bundle and support system (including flow distribution baffle, tube support plates, and anti-vibration bars) for potential vibration and wear. Consideration was given to potential sources of tube excitation including primary fluid flow within the U-tubes, mechanically induced vibration, and secondary fluid flow on the outside of the tubes. The effects of primary fluid flow and mechanically induced vibration are considered negligible during normal operation. The primary source of potential tube degradation due to vibration is due to the hydrodynamic excitation by the secondary fluid on the outside of the tubes. The three potential tube vibration mechanisms due to hydrodynamic excitation by the secondary fluid on the outside of the tubes are vortex shedding, turbulence, and fluidelastic vibration.

The RSG analyses showed that calculated fluidelastic stability ratios are within acceptance criteria, displacements and bending stresses from turbulence are small, and calculated wear depths after the 40 calendar year design operating period are within available design margins for local tube wear. The maximum calculated tube wear depth after the 40 calendar year design operating period is within the plugging margin available for steam generator operation. The flow induced vibration and wear analyses therefore demonstrate that the RSG will not experience unacceptable tube degradation due to tube vibration and wear during the 40 calendar year design operating period.

The RSG flow induced vibration and wear analyses including methodology, acceptance criteria and results, are documented in the RSG Flow Induced Vibration Analysis Report.

4.7.7.4 Tube Plugging Limits (Draft Regulatory Guide 1.121 Analysis)

Draft Regulatory Guide 1.121 (Reference 6) describes an acceptable method for establishing the limiting safe condition of degradation in the tubes beyond which tubes found defective by the established in-service inspection methods shall be removed from service. This level of acceptable degradation is referred to as the "plugging limit."

RSG analyses were performed to define the "structural limits" for an assumed uniform thinning mode of tube degradation in both the axial and circumferential directions using the ASME Code minimum material properties. The assumption of uniform thinning is generally regarded to result in a conservative structural limit for all flaw types occurring in the field. The allowable tube plugging limits, in accordance with draft

Regulatory Guide 1.121, are obtained by incorporating into the resulting structural limit a growth allowance for continued operation until the next scheduled inspection and also an allowance for eddy current measurement uncertainty. Calculations are performed to establish the structural limit for the straight leg (free span) region of the tube for degradation over an unlimited axial extent and for degradation over a limited axial extent at the tube support plate and AVB intersections.

The RSG analyses establish the tube structural limits for the straight leg (free span), tube support plate and AVB tube locations based on the normal and accident conditions. Leakage monitoring using the EPRI PWR Primary-to-Secondary Leak Guidelines (Reference 7) provides a reasonable likelihood that the plant can be shut down before a single tube postulated to be leaking would rupture under either normal or accident conditions.

The RSG draft Regulatory Guide 1.121 analysis including methodology, acceptance criteria and results are documented in the RSG Regulatory Guide 1.121 Analysis Report.

4.7.7.5 Feedwater Inlet Distribution System

Steam generator water hammer (SGWH) has occurred, particularly in certain early pressurized water reactor steam generator designs having feedrings equipped with bottom discharge holes and, at one time, was considered to be an unresolved safety issue. NUREG-0918, "Prevention and Mitigation of Steam Generator Water Hammer Events in PWR Plants" (Reference 8) documents the recommendations reached in addressing feedwater inlet distribution system water hammer. The NUREG-0918 recommendations for the prevention and mitigation of SGWH include modifications to both the steam generator design and plant operating procedures. Branch Technical Position ASB 10-2, "Design Guidelines for Avoiding Water Hammers in Steam Generators" (Reference 9) also provides recommendations for modifications and tests to verify that unacceptable water hammer will not occur.

The RSG feedwater inlet distribution system incorporates design features that prevent or mitigate water hammer, consistent with the NRC recommendations in NUREG-0918 and ASB 10-2. The feedwater inlet distribution system introduces feedwater into the steam generator through an elevated top discharge feedring with spray nozzles. The feedring is welded to the feedwater inlet nozzle and incorporates a welded thermal sleeve. The elevated feedring minimizes the time required to fill the feedring and the potential for thermal stratification in the feedring and feedwater nozzle during low flow filling and steady state operations. The welded feedring to feedwater nozzle connection minimizes the potential for draining the feedring. The top discharge of the feedring, through spray nozzles, minimizes the potential for vapor formation in the feedring. The thermal sleeve in the feedwater nozzle minimizes the effect of introducing cold feedwater, including auxiliary (emergency) feedwater, into the feedwater nozzle and feedring. These feedwater inlet distribution system design features minimize the potential for thermal stratification in the feedring and feedwater nozzle (including the feedwater piping elbow at the feedwater nozzle entrance) and the potential for SGWH. Feedwater inlet distribution systems using these design features have been proven in other operating plants to prevent or mitigate the occurrence of SGWH.

The technical evaluation of the RSG feedwater inlet distribution system with respect to NRC recommendations for the prevention and mitigation of water hammer is documented in the RSG Feedwater Inlet Distribution System Report.

4.7.8 Design Evaluations

Design evaluations have been performed to assess compliance of the Model 54F RSGs with regulatory guidance and acceptance criteria. Table 4.7-7 lists the regulatory guidance that has been considered in the design, analysis, fabrication and testing of the BVPS-1 Model 54F RSGs. Although the BVPS-1 licensing basis does not include the Standard Review Plan, the design evaluations included consideration of the regulatory guidance contained in Section 5.4.2, "Steam Generators," Section 5.4.2.1, "Steam Generator Materials" and Section 5.4.2.2, "Steam Generator Tube Inservice Inspection" of NUREG-0800, "Standard Review Plan" (Reference 10).

The following sections provide evaluations of steam generator materials (including the selection and fabrication of materials, design effects on materials, compatibility of tubing with the primary and secondary coolants, and cleanup of secondary side) and steam generator tube inservice inspection (including access, baseline inspections, and inspection program). This section also addresses the topics of forced convection, natural circulation, mechanical and flow induced vibration, and allowable tube wall thinning under accident conditions.

4.7.8.1 Steam Generator Materials

4.7.8.1.1 Selection and Fabrication of Materials

The RSG pressure boundary materials are selected and fabricated in accordance with the requirements of Section III of the ASME Code. Table 4.7-3 identifies the ASME Code Sections and Code Cases used in material selection. The types of materials for major RSG components are listed in Table 4.7-6.

Testing and operational experience (Reference 2) justify the selection of thermally treated (TT) Alloy 690 for steam generator tubes and divider plate. The interior surfaces of the reactor coolant channel head and nozzles are weld clad with austenitic stainless steel. The primary side of the tubesheet is weld clad with Alloy 690. The tubes are hydraulically expanded the full length of the tubesheet bore after the ends are seal welded to the tubesheet cladding. The tube-to-tubesheet fusion welds are performed in compliance with Sections III and IX of the ASME Code and are dye penetrant inspected and leak proof tested.

During manufacture, cleaning is performed on the primary and secondary sides of the steam generator in accordance with written procedures which follow the guidance of Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," (Reference 11) and ANSI Standard N45.2.1, "Cleaning of Fluid Systems and Associated Components for Nuclear Power Plants" (Reference 12). The steam generators are shipped from the manufacturing facility pressurized with dry nitrogen suitable for extended periods of storage.

Fracture toughness of ferritic pressure boundary materials is provided in compliance with Appendix G of 10 CFR 50 (Reference 13) and Article NB-2300 of Section III of the ASME Code.

4.7.8.1.2 Design Effects on Materials

Several features are employed to control the regions where deposits would tend to accumulate and cause corrosion. To avoid significant crevice areas at the tubesheet, the tubes are hydraulically expanded to the

full depth of the tubesheet bore after the tube ends are seal welded to the Alloy 690 cladding on the primary side of the tubesheet.

Several corrosion mechanisms have been identified in operating nuclear power plant steam generators that can result in unacceptable tube degradation. The RSG design addresses these degradation mechanisms and provides a design that is very resistant to tube corrosion. Provided that appropriate water chemistry is maintained, the RSGs are designed for a cumulative operating period of 40 calendar years.

Tube wastage is a corrosion mechanism that results in a general thinning of the tubing. This mechanism was associated with phosphate chemistry. The use of all volatile treatment (AVT) water chemistry has minimized the possibility for the occurrence of tube wastage.

Several features in the RSG minimize crevice areas and the potential for deposition of contaminants from the secondary side flow. Such crevices and deposits could otherwise produce a local environment allowing adverse conditions to develop and result in potential material corrosion.

Corrosion of carbon steel support plates in early model steam generators in some cases resulted in denting of the tubes. Corrosion of the plate can reduce the size of the drilled hole in the plate since the corrosion product has a larger specific volume than the original steel. Continued progression of the corrosion can lead to a tight crevice and a reduction of the tube diameter. These conditions result in a concentration of chemicals and higher stress in the tubes. This may result in stress corrosion cracking.

The use of stainless steel support plates in the RSG precludes the denting of the tubes. The use of a quatrefoil hole minimizes the potential for concentration of chemicals at the interface between the tube and support plate. It provides high sweeping velocities at the tube and tube support plate intersections. The sweeping velocities through the support plate reduce the sludge accumulation in the tube-to-tube support crevices. This support plate design contributes to a high circulation ratio. The increased flow from a high circulation ratio results in increased flow in the interior of the bundle, as well as horizontal velocity across the tubesheet, which reduces the tendency for sludge deposition.

The tubes are welded at the tube end and hydraulically expanded essentially over the full depth of the tubesheet. Expansion of the tube provides the capability to control secondary water ingress to the tube-to-tubesheet crevice. The transition between the expanded and unexpanded portions of the tube is a location of residual stress. The use of a roller to effect the expansion would leave a relatively high residual stress at the transition. The use of an explosive expansion would reduce the residual stress but there would be less control on the vertical location of the transitions and the interference fit between the tubesheet and the tube. Therefore, roll expansion and explosive expansion are not used for RSG tubes. The use of a hydraulic expansion process in the RSGs produces residual stresses smaller than from other expansion methods in the transitions. Residual stresses are minimized by tight control of the pre-expansion clearance between the tube and tubesheet hole. The length of the expansion is carefully controlled to minimize the potential of an over-expanded condition above the tubesheet and the extent of unexpanded tube at the top of the tubesheet. Along with measurement of the tubesheet thickness, hydraulic expansion minimizes the crevice between the tube and tubesheet. These features minimize the potential for ODSCC at the top of the tubesheet.

4.7.8.1.3 Compatibility of Tubing with Primary and Secondary Coolants

Thermally treated (TT) Alloy 690 is used for the RSG tubes. Alloy 690 TT has been proven through both laboratory testing and operational experience (Reference 2) to provide increased corrosion resistance compared to mill annealed Alloy 600 with regard to PWSCC and ODSCC.

Industry corrosion tests which subjected the steam generator tubing material to simulated steam generator water chemistry have indicated that the loss due to general corrosion over the 40-year design operating period is small compared to the tube wall thickness. Testing to investigate the susceptibility of heat exchanger construction materials to stress corrosion in caustic and chloride aqueous solutions has indicated that Alloy 690 TT has excellent resistance to corrosion in severe operating water conditions and provides as good or better corrosion resistance as either Alloy 600 or Alloy 800. Many reactor years of successful operation have shown the same low general corrosion rates as indicated by laboratory tests. Plants that have used Alloy 690 TT tubing in their replacement steam generators have not experienced corrosion-induced degradation.

The all volatile treatment (AVT) secondary water chemistry control program minimizes the possibility of the tube wall thinning phenomenon. Successful AVT operation requires maintenance of low concentrations of impurities in the steam generator water. This reduces the potential for formation of highly concentrated solutions in low-flow zones, which is a precursor of corrosion. By restricting the total alkalinity in the steam generator and prohibiting extended operation with free alkalinity, the all volatile treatment program minimizes the possibility for intergranular corrosion in localized areas due to excessive levels of free caustic.

Laboratory testing shows that Alloy 690 TT tubing is compatible with the AVT environment. Isothermal corrosion testing in high-purity water shows that Alloy 690 TT exhibiting normal microstructure tested at normal engineering stress levels is not susceptible to intergranular stress corrosion cracking in extended exposure to high-temperature water. These tests also show that no general type corrosion occurred. Field experience with Alloy 690 TT tubing in operation since 1989 has been excellent.

Model boiler tests evaluate similar AVT chemistry guidelines adopted by Westinghouse and EPRI. Conformance to the guidelines enhances tube life when operation with contaminant ingress is limited. Extensive operating data has been accumulated for all volatile treatment water chemistry.

A comprehensive program of steam generator inspections, including the recommendations of Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," (Reference 14) provides for detection of any degradation that might occur in the steam generator tubing.

High margins against primary water stress corrosion cracking exist with the specification of Alloy 690 TT tubing. Alloy 690 is resistant to primary water stress corrosion cracking over the range of anticipated operating environments. The tubing is thermally treated according to a laboratory-derived treatment process and is generally consistent with industry-accepted and EPRI procedures.

The tube support plates in the RSG are fabricated of Type 405 stainless steel. Laboratory tests show that this material is resistant to corrosion in the AVT environment. If corrosion of ferritic stainless steel were

to occur because of the concentration of contaminants, the volume of the corrosion products is essentially equivalent to the volume of the parent material consumed.

4.7.8.1.4 Cleanup of Secondary Side

During steam generator shutdown, inspection results may indicate the need for secondary side cleaning. Sludge lancing may be performed by inserting a hydraulic jet through access openings (handholes) to loosen sludge deposits. The hydraulic water jet impinges at the tubesheet secondary side surface at high velocity causing the material to loosen and accumulate on the top of the tubesheet. These depositions are then removed utilizing a suction pump.

Access is available to perform sludge lancing utilizing the four 6-inch handholes located just above the tubesheet surface. Lancing is performed by inserting the hydraulic jet into each of two handholes for traversing the tube lane and the periphery of the tube bundle just above the tubesheet surface. The other two hand holes located 90 degrees apart are used to clean the areas which are located farthest from the tube lane. This method, when used in conjunction with an AVT secondary water chemistry control program during normal operation, provides cleaning of the secondary side surface areas near the tubesheet.

4.7.8.2 Steam Generator Inservice Inspections

4.7.8.2.1 Access

The steam generator contains design features that provide access for inservice inspection and replacement or repair of Class 1 and 2 components, including the plugging of individual tubes. This allows for implementation of Section XI of the ASME Code, "Rules for Inspection and Testing of Light Water Coolant Plants," (Reference 15) and Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," (Reference 14). Access openings are provided to: 1) inspect, repair, or replace components; 2) detect, locate and plug tubes with a wall defect, and 3) perform volumetric inspections on Safety Class 1 welds on the primary side. These openings include four manways (two for access to both sides of the primary (reactor coolant) channel head, and two for inspection and maintenance of the secondary side upper internals), four 6-inch handholes located just above the tubesheet surface, two 6-inch handholes located above the flow distribution baffle, and two 4-inch inspection ports located above the top tube support plate in the U-bend region. Insulation can be removed as necessary to provide the required access.

4.7.8.2.2 Baseline Inspection

All tubes in each steam generator will be given a baseline volumetric examination prior to service using eddy current techniques and equipment in accordance with Regulatory Guide 1.83.

The vessel welds, attachments, and bolting will be examined as required by ASME Section XI after the completion of the pressure tests required by ASME Section III. Examination results will be retained for comparison to future inservice inspection data.

4.7.8.2.3 Inspection Program

4.7.8.2.3.1 Number of Steam Generators to be Inspected

The number of steam generators to be inspected will be in accordance with the Technical Specifications. During the first examination of steam generator tubing performed after installation, the tubes in two steam generators will be examined. The tubes in the remaining steam generator will be examined during the following inspection.

After the second inservice inspection, all steam generators will have been examined once. Further inspections may be limited to any one steam generator on a rotating schedule 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 specific steam generators may be found to be more severe than those in the other steam generators. Under such circumstances, the sample sequence will be modified to inspect the steam generator with the most severe conditions.

4.7.8.2.3.2 Steam Generator Tube Inspection Procedure

During each inservice inspection period, the minimum number of tubes per generator to be inspected will be in accordance with the Technical Specifications. Results will be categorized and corrective actions taken, in accordance with the Technical Specifications.

4.7.8.2.3.3 Steam Generator Vessel Inspection Procedure

During each inservice inspection period, examinations and repairs (as applicable) will be performed as required by ASME Section XI.

4.7.8.2.3.4 Inspection Frequency of Tubes and Vessels

Inspections of steam generator tubes will be performed at the frequencies specified in the Technical Specifications.

Inservice inspections of the steam generator vessel will be performed in accordance with the frequency specified in the UFSAR.

4.7.8.2.3.5 Reports of Inservice Inspection

Inservice inspection reports of steam generator tubes will be provided to the NRC in accordance with the Technical Specifications.

4.7.8.3 Forced Convection

The effective steam generator heat transfer coefficient is determined by the physical characteristics of the steam generator and the fluid conditions in the primary and secondary systems for the normal full power design case. It includes a conservative allowance for fouling and uncertainty. Adequate heat transfer area is provided so that the full design heat transfer rate is achieved.

4.7.8.4 Natural Circulation Flow

The driving head created by the change in reactor coolant density as it is heated in the core and rises to the reactor vessel outlet nozzle initiates convection circulation. This circulation is enhanced by the fact that the steam generators, which provide a heat sink, are at a higher elevation than the reactor core which is the heat source. Thus, natural circulation is available for the removal of core decay heat during shutdown operations in the unlikely event of loss of forced circulation.

4.7.8.5 Mechanical and Flow Induced Vibration

Potential sources of tube excitation are considered, including primary fluid flow within the U-tubes, mechanically induced vibration, and secondary fluid flow on the outside of the U-tubes. The effects of primary fluid flow and mechanically induced vibration, including those developed by the reactor coolant pump, are acceptable during normal operation. The primary source of potential tube degradation due to vibration is the hydrodynamic excitation of the tubes by the secondary fluid. This area has been emphasized in both analyses and tests, including evaluation of steam generator operating experience.

Three potential tube vibration mechanisms related to hydrodynamic excitation of the tubes have been identified and evaluated. These include potential flow-induced vibrations resulting from vortex shedding, turbulence, and fluidelastic vibration mechanisms.

Non-uniform, two-phase turbulent flow exists throughout most of the tube bundle. Therefore, vortex shedding is possible only for the outer few rows of the inlet region. Moderate tube response caused by vortex shedding is observed in some carefully controlled laboratory tests on idealized tube arrays. However, no evidence of tube response caused by vortex shedding is observed in steam generator scale model tests simulating the inlet region. Bounding calculations consistent with laboratory test parameters confirmed that vibration amplitudes would be acceptably small, even if the carefully controlled laboratory conditions were unexpectedly reproduced in the RSG.

Flow-induced vibrations due to flow turbulence are also small; root mean square amplitudes are less than allowances used in tube sizing. These vibrations cause stresses that are significantly below fatigue limits for the tubing material. Therefore, neither unacceptable tube wear nor fatigue degradation due to secondary flow turbulence is anticipated.

Fluidelastic tube vibration is potentially more significant than either vortex shedding or turbulence because it is a self-excited mechanism. Relatively large tube amplitudes can feed back proportionally large tube driving forces if an instability threshold is exceeded. Tube support spacing in both the tube support plates and the anti-vibration bars in the U-bend region provides tube response frequencies such that the instability threshold is not exceeded for secondary fluid flow conditions for tubes effectively supported. This approach provides large margins against initiation of fluidelastic vibration for tubes effectively supported by the tube support system.

The RSG includes a number of features that minimize the potential for tube wear at tube supports and anti-vibration bars. Provisions to minimize the potential for wear include the spacing between the tube supports, the configuration of the broached hole through the tube support plate, the surface finish of the

broached hole in the tube support plate, the clearance between the tube and the hole in the tube support plate, tube support plate material selection, and the configuration of the anti-vibration bar assemblies.

As outlined, analyses and tests demonstrate that unacceptable tube degradation resulting from tube vibration is not expected for the RSGs. Operating experience with steam generators having the same size tubes and similar flow conditions supports this conclusion.

4.7.8.6 Allowable Tube Wall Thinning Under Accident Conditions

The tubes and the inservice inspection plan for the RSGs are in conformance with the requirements of Regulatory Guide 1.83 and the ASME Code, Section XI. Regulatory Guide 1.83 provides guidance on the sample size and the inspection interval. The ASME Code, Section XI establishes 40% as the default plugging limit.

The steam generator tubes, existing originally at their minimum wall thickness and reduced by a conservative general corrosion and erosion loss, provide an adequate safety margin (sufficient wall thickness) in addition to the minimum required wall thickness so that the maximum stress does not exceed the allowable stress limit, as defined by the ASME Code, Section III.

In addition to the analysis required by the ASME Code, an analysis is also performed to establish the minimum wall thickness of the tubes using the guidance of draft Regulatory Guide 1.121.

The draft Regulatory Guide 1.121 analysis is performed for the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down and all anticipated transients included in the design specification) and design basis accidents. The pressure loads corresponding to full power operation are bounding relative to allowable tube degradation. The allowable degradation depth and the through-wall allowance for growth and NDE uncertainty are determined to satisfy the 40% tube plugging limit.

The draft Regulatory Guide 1.121 analysis includes an assessment of the loads that result from postulated accident conditions, including a design basis earthquake (DBE) in combination with a loss of coolant accident (LOCA) break or a steam line break (SLB).

For the DBE plus LOCA analysis of dynamic loadings, the MULTIFLEX (3) computer code (Reference 16) is used to generate the dynamic response (i.e., pressure time histories) due to a LOCA pipe break. The ANSYS computer code is used to calculate the structural response of the tubes to the LOCA pressure time history. The Westinghouse WECAN/Plus computer code is used for the structural analysis of the DBE loading. MULTIFLEX and WECAN/Plus are Westinghouse-developed proprietary computer codes. WECAN/Plus is a successor to the WECAN (Westinghouse Electric Computer Analysis) computer code that has been used extensively by Westinghouse in the design analyses of NSSS Seismic Category I components designated as ASME Code Class 1, 2 or 3. The WECAN computer code is described in Section B.3.9 of the BVPS-1 UFSAR (Reference 1). The ANSYS computer code is a general purpose finite element structural analysis computer code that is available in the public domain for use in performing analysis of structures to various types of applied loadings, including the dynamic response of structures.

For the postulated SLB accident, the predominant primary tube stresses result from the primary to secondary side through-wall pressure gradient. The peak differential pressures for this event are obtained from the results of a transient blowdown analysis that is based on a full double-ended rupture of the main steam line where the secondary side of the faulted steam generator blows down to the ambient pressure.

The analysis of the tubes for combined DBE plus SLB loads considers the combined effects of the applicable seismic and steam line break loads.

4.7.9 Quality Assurance

The overall quality of RSG design and construction is controlled by the RSG Quality Assurance Program, which is in compliance with 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" (Reference 17). For all pressure boundary components, the Quality Assurance Program is also in compliance with Section III of the ASME Code (Reference 5) and ASME NQA-1 (Reference 18). Quality assurance records are maintained in accordance with the guidelines in 10 CFR 50, Appendix B.

4.7.9.1 Nondestructive Examination Tests

The Quality Assurance Program includes nondestructive examination (NDE) tests that are performed to control the quality of the RSGs during fabrication. All NDE tests including acceptance standards are in accordance with the requirements of the ASME Code, Section III, Section V (Reference 19), and Section XI, as applicable. NDE examinations include radiographic (RT), liquid (dye) penetrant (PT), magnetic particle (MT), ultrasonic (UT), and eddy current (ET) tests.

Table 4.7-8 summarizes the type of NDE performed for the various RSG components.

4.7.9.2 Functional Tests

The Quality Assurance Program includes functional tests. The functional tests include shop hydrostatic pressure tests of all RSG tubes after bending and shop hydrostatic pressure tests of all RSGs after assembly. The hydrostatic pressure tests are performed in accordance with the requirements of the ASME Code, Section III.

In addition to hydrostatic pressure tests, helium gas leak tests of the tube-to-tubesheet welds are performed prior to the shop hydrostatic pressure tests.

4.7.9.3 Visual and Dimensional Examination

Following assembly, the RSG and its parts (including welds) are subjected to visual and dimensional examination per ASME Section V to confirm compliance with applicable requirements of design drawings and specifications.

4.7.9.4 Preservice Inspection

Upon completion of the ASME III hydrostatic pressure tests and prior to shipment of the RSG assemblies, baseline preservice inspections (PSI) are performed for RSG welds and tubing.

Baseline volumetric ultrasonic and surface examinations are performed on RSG welds requiring inservice inspection (ISI). This PSI of welds is performed in accordance with the requirements of the ASME Code, Section XI.

Baseline eddy current tests are performed for RSG tubing over the entire length (tube end to tube end) of each tube in each RSG. The PSI eddy current testing is performed in accordance with Section XI of the ASME Code and the EPRI PWR Steam Generator Examination Guidelines, Revision 5 (Reference 20).

4.7.10 Conclusions

The RSG design and analyses meet or exceed the regulatory requirements and the codes and standards in effect at the time of the original plant construction. The RSGs are designed and fabricated to more recent editions of the ASME Code and related codes and standards. This is consistent with accepted practice for the design of new systems and/or major modifications to existing systems, which is to design the replacement components to the latest edition of the applicable codes and standards.

The RSGs are designed, analyzed and fabricated to the quality requirements of 10 CFR Part 50 Appendix B (Reference 17) and applicable industry codes and standards are met. The RSG key design features are developed such that the appropriate design technical requirements are met. Lessons learned from the design and operation of the BVPS-1 OSGs as well as other original and replacement steam generators were incorporated into the design of the BVPS-1 RSGs, including enhanced tube support plate design to minimize the entrapment of corrosive materials, tubing composition and fabrication controls to minimize susceptibility to corrosion (including stress corrosion cracking, intergranular corrosion, and wastage), and tube-to-tubesheet expansion process to minimize residual stress and the crevice between the tube and tubesheet. Analyses have been performed in the analytical areas of thermal-hydraulic performance, structural integrity, flow induced vibration and wear, tube plugging limits, and feedwater inlet distribution system to show that acceptance criteria are satisfied. Evaluations have been performed in the areas of steam generator materials, inservice inspection, forced convection, natural circulation, mechanical and flow induced vibration, and allowable tube wall thinning under accident conditions to show that acceptance criteria are satisfied. These analyses and evaluations show that the BVPS-1 RSGs satisfy applicable licensing requirements and acceptance criteria and that they are acceptable replacement components for the BVPS-1 OSGs.

4.7.11 References

1. Beaver Valley Power Station Unit 1 Updated Final Safety Analysis Report, Revision 21.

2. EPRI Report TR-016743-V2R1, Volume 2, "Guidelines for Procurement of Alloy 690 Steam Generator Tubing," Electric Power Research Institute (EPRI), Palo Alto, CA, April 1999.

3. EPRI Report TR-102134-R5, "PWR Secondary Water Chemistry Guidelines," Electric Power Research Institute (EPRI), Palo Alto, CA, June 2000.

4. American National Standard Criteria for Safety Systems for Nuclear Power Generating Systems, ANSI/IEEE-603-1980.

5. ASME Boiler and Pressure Vessel Code, Section III, "Rules for Construction of Nuclear Power Plant Components," 1989 Edition, No Addenda, The American Society of Mechanical Engineers, New York, New York, USA.

6. US NRC Regulatory Guide 1.121 (DRAFT), "Bases for Plugging Degraded PWR Steam Generator Tubes (For Comment)," August 1976.

7. EPRI Report TR-104788-R2, "PWR Primary-to-Secondary Leak Guidelines – Revision 2," Electric Power Research Institute (EPRI), Palo Alto, CA, 2000.

8. US NRC NUREG-0918, "Prevention and Mitigation of Steam Generator Water Hammer Events in PWR Plants," December 1982.

9. US NRC Branch Technical Position ASB 10-2, "Design Guidelines for Avoiding Water Hammers in Steam Generators," April 1984.

10. US NRC NUREG-0800, "Standard Review Plan," Section 5.4.2 Rev. 1, "Steam Generators (PWR)," Section 5.4.2.1 Rev. 2, "Steam Generator Materials," and Section 5.4.2.2 Rev. 1, "Steam Generator Tube Inservice Inspection," July, 1981.

11. US NRC Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," 1973.

12. ANSI Standard N45.2.1, "Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants," 1980.

13. Title 10, "Energy," Code of Federal Regulations, Part 50, "Domestic Licensing of Production and Utilization Facilities," Appendix G, "Fracture Toughness Requirements."

14. US NRC Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," 1975.

15. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," 1989 Edition, No Addenda, The American Society of Mechanical Engineers, New York, New York, USA.

16. WCAP-9735, Revision 2 (Westinghouse Proprietary Class 2)/WCAP-9736, Revision 1 (Non-Proprietary), "MULTIFLEX 3.0 A FORTRAN IV Computer Program for Analyzing Thermal-Hydraulic-Structural System Dynamics Advance Beam Model," K. Takeuchi, et al., February 1998.

17. Title 10, "Energy," Code of Federal Regulations, Part 50, "Domestic Licensing of Production and Utilization Facilities," Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants."

18. ANSI/ASME NQA-1, "Quality Assurance Program Requirements for Nuclear Facilities," 1994.

19. ASME Boiler and Pressure Vessel Code, Section V, "Nondestructive Examination," 1989 Edition, no Addenda, The American Society of Mechanical Engineers, New York, New York, USA.

20. EPRI Report TR-107569, Volume 1, PWR Steam Generator Examination Guidelines: Revision 5, Electric Power Research Institute (EPRI), Palo Alto, CA, September 1997.

Table 4.7-1
BVPS-1 Replacement Steam Generator Design Data[1]

Parameter	Model 54F RSG 2910 MWt	Model 51 OSG[2] 2660 MWt (Original Design)
Number of Steam Generators	3	3
Design Pressure, reactor coolant/steam, psig	2,485/1,085	2,485/1,085
Reactor Coolant Hydrostatic Test Pressure (tube side-cold), psig	3,107	3,107
Design Temperature, reactor coolant/steam, °F	650/600	650/600
Reactor Coolant Flow, 10^6 lb/hr	33.7 to 33.1[5]	33.6
Total Heat Transfer Surface Area, ft^2	54,500	51,500
Heat Transferred, 10^6 Btu/hr	3,310	3,030
Steam Conditions at Full-Load, outlet nozzle:	–	–
Steam flow, 10^6 lb/hr	4.00 to 4.34[4][5]	3.85
Steam temperature, °F	490.2 to 515.8[4][5]	516.8
Steam pressure, psig	623 to 783[4][5]	790
Maximum moisture carryover, wt %	0.10	0.25
Feedwater temperature, °F	400 to 455[5]	436.9
Overall Height, ft-in.	67-9	67-8
Shell	–	–
Upper Shell Outer Diameter (OD), in.	176.92	175.75
Lower Shell Outer Diameter (OD), in.	135.5	135
Number of U-tubes	3,592	3,388
U-tube Outer Diameter, in.	0.875	0.875
Tube Wall Thickness, (nominal), in.	0.050	0.045[3]
Manways	–	–
Number	4	4
Inside Diameter, in.	16	16
Handholes	–	–
Number	6 (Handholes) 2 (Inspection Ports)	2
Inside Diameter, in.	6 (Handholes) 4 (Inspection Ports)	6

Table 4.7-1 (continued) BVPS-1 Replacement Steam Generator Design Data[1]		
Parameter	Model 54F RSG 2910 MWt	Model 51 OSG[2] 2660 MWt (Original Design)
Reactor Coolant Water Volume (Rated Load/No Load), ft^3	956 to 1,136/1,136[5]	1,080/1,080
Primary Side Fluid Heat Content (Rated Load/No Load), 10^6 Btu	24.69 to 29.66/29.06[5]	28.23/27.63
Secondary Side Water Volume (Rated Load/No Load), ft^3	1,836 to 2,083/3,419[5]	2,080/3,350
Secondary Side Steam Volume (Rated Load/No Load), ft^3	3,797 to 3,550/2,214[5]	3,788/2,518
Secondary Side Fluid Heat Content (Rated Load/No Load), 10^6 Btu	49.52 to 57.40/92.17[5]	58.59/91.48

Notes:

(1) Quantities are for each steam generator.

(2) Model 51 OSG design data are from BVPS-1 UFSAR Table 4.1-5.

(3) Tube wall thickness (minimum) is equal to 0.045 inch.

(4) Steam conditions are limited to minimums of 700 psia and 503.1°F. For analysis purposes, maximum steam conditions are 831 psia, 522.6°F and 4.347 x 10^6 lb/hr.

(5) Design data for Full Load (Rated Load) operation is provided for design ranges for reactor vessel average temperature (566.2° to 580.0°F), feedwater temperature (400° to 455°F), and steam generator tube plugging level (0% to 22%). Design data for No Load operation is provided for 0% steam generator tube plugging level.

Table 4.7-2
BVPS-1 Replacement Steam Generator Key Design Features

Parameter	Model 54F RSG 2910 MWt	Model 51 OSG 2660 MWt (Original Design)
SG Overall Dimensions (Heights and Distances)		
Height from top of tubesheet to lower wide range level taps, in.	11.8[1]	12.0
Height from top of tubesheet to lower narrow range level taps, in.	374.8	443.0
Height from top of tubesheet to upper wide range/narrow range level taps, in.	586.8[1]	587.0
Height from top of tubesheet to nominal indicated water level (NWL), in.	513.0	505.9
Height from top of tubesheet to top of tube bundle, in.	417.5	417.0
Overall height, in.	813	812
SG Primary Side Inlet and Outlet Plenums		
Thickness of tubesheet (including clad), in[6]	21.43	21.1875
Primary side total volume at 0% SGTP (ambient), ft^3	1136	1081
Primary side thermal design flow, gpm	87,200	88,500
Primary side delta-P at 0% SGTP and thermal design flow, psi	25.62 to 26.03[5]	30.46[5]
SG Tube and Tube Bundle		
Straight length of tubes without tubesheet thickness (shortest/longest), in.[7]	353.57/357.57	356.75
Largest tube radius, in.	59.49	59.84
Smallest tube radius, in.	3.14	2.19
Tube outer diameter (nominal), in.	0.875	0.875
Tube wall thickness (nominal), in.	0.050	0.050
Number of tubes	3,592	3,388
Total heat transfer area (secondary side), ft^2	54,500	51,500
Tube material	Alloy 690 TT[2]	Alloy 600 MA[2]
Tube pitch, in.	1.225	1.281
Tube pitch arrangement	Square	Square
Tube volume, average of one tube, ft^3	0.2287	0.2253
Tube hole configuration (tube support plates/flow distribution baffle)	Quatrefoil/Octafoil	Round/–
Number of tube support plates/flow distribution baffles	7/1	7/–
Tube support plates/flow distribution baffle material	405 SS[3]	Carbon Steel

Table 4.7-2 (continued) BVPS-1 Replacement Steam Generator Key Design Features		
Parameter	Model 54F RSG 2910 MWt	Model 51 OSG 2660 MWt (Original Design)
Number of U-bend AVBs	3 Sets	2 Sets
U-bend AVB material	405 SS[3]	Alloy (Inconel) 600
Primary flow area (0% SGTP), ft^2	11.767	10.956
SG Secondary Side Assembly		
Wrapper inner diameter, in.	123.50	123.50
Wrapper opening height, in.	14.0	14.0
Lower shell inner diameter, in.	129.38	129.38
Upper shell inner diameter, in.	168.50	168.50
Lower shell outer diameter, in.	135.5	135.0
Upper shell outer diameter, in.	176.92	175.75
Secondary side total volume, ft^3	5633	5726
Primary separator design	Centrifugal/w Low Pressure Drop	Centrifugal
Number of primary separators	16	3
Diameter of primary separators (ID), in.	19.5	56
Swirl vane angle, degrees	30	37
Secondary separator design	Single Tier (6 Banks)	Two Tier (8 Banks)
Secondary separator face area, ft^2	215	179
Steam nozzle venturi flow limiter flow area, ft^2	1.388	4.6[4]
Steam nozzle venturi flow limiter hydraulic diameter, in.	6.03	N/A[4]
Number of steam nozzle venturi flow limiters	7	N/A[4]
Secondary side circulation ratio at full-load	3.3 to 3.6	5.0
Secondary side delta-P at full-load (from inlet of feedwater nozzle to outlet of steam nozzle), psi	19.5 to 25.4	23.4
SG Weight and Center of Gravity (CG)		
Total dry weight, without platform, lb	718,000 ± 15,000	660,250
Total operating weight (full power), without platform, lb	878,000 ± 20,000	808,160
Total flooded weight (with 70°F water), without platform, lb	1,141,000 ± 22,000	1,075,090
Dry CG (elevation measured from vessel support pad datum plane), in.	362 ± 4	289.5[8]

Table 4.7-2 (continued)
BVPS-1 Replacement Steam Generator Key Design Features

Parameter	Model 54F RSG 2910 MWt	Model 51 OSG 2660 MWt (Original Design)
Operating (full power) CG (elevation measured from vessel support pad datum plane), in.	354 ± 4	283.6(8)
Flooded (70°F water) CG (elevation measured from vessel support pad datum plane), in.	389 ± 4	322.2(8)

Notes:

(1) The RSG upper wide range/upper narrow range level taps and the RSG lower wide range level taps are located at the same plant elevation as the OSG but differ by 0.2 inch due to changes in the distance from the support pads to the top of the tubesheet between RSGs and OSGs.

(2) TT – Thermally Treated, MA – Mill Annealed

(3) SS – Stainless Steel

(4) The OSG steam nozzle does not include venturi flow limiters to limit flow area.

(5) Primary side delta-P for OSG based on original thermal design flow (TDF) of 88,500 gpm/loop and primary side delta-P for RSG based on TDF of 87,200 gpm/loop.

(6) Includes 0.25 in. cladding thickness.

(7) Smallest radius tube/largest radius tube.

(8) The OSG CG elevation is measured from the top of the tubesheet.

Table 4.7-3 BVPS-1 Replacement Steam Generator ASME Code Section Requirements	
1.	ASME Boiler and Pressure Vessel Code, Section II, "Material Specifications," 1989 Edition, No Addenda.
2.	ASME Boiler and Pressure Vessel Code, Section III, "Rules for Construction of Nuclear Division 1 Power Plant Components," 1989 Edition, No Addenda. Code Case N-20-3, "SB-163, Nickel-Chromium-Iron Tubing (Alloy 600 and 690) and Nickel-Chromium-Iron Alloy 800 at a Specified Minimum Yield Strength of 40.0 ksi and Cold Worked Allow 800 at a Minimum Yield Strength of 47.0 ksi, Section III, Division I, Class 1." Code Case N-71-16, "Additional Materials for Subsection NF Component Supports Fabricated by Welding." Code Case N-411-1, "Alternative Damping Values for Response Spectra Analysis of Class 1, 2 and 3 Piping" (See BVPS UFSAR for requirements on use of N-411). Code Case N-474-2, "Design Stress Intensities and Yield Strength Values for UNS N06690 with Minimum Yield Strength of 35 ksi." Appendix XXIII, "Qualification and Duties of Specialized Professional Engineers," 1995, 1996 Addenda. NCA-3250, "Provision of Design Specifications," 1989 Edition, No Addenda.(1)
3.	ASME Boiler and Pressure Vessel Code, Section V, "Nondestructive Examination," 1989 Edition, No Addenda.
4.	ASME Boiler and Pressure Vessel Code, Section IX, "Welding and Brazing Qualifications," Latest Edition.(2) Code Case 2142-1, "F Number Grouping for Ni-Cr-Fe Classification UNS N06052 Filler Metal."(3) Code Case 2143-1, "F Number Group for Ni-Cr-Fe Classification UNS W86152 Weld Electrode."(3)
5.	ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," 1989 Edition, No Addenda. Code Case N-401-1, "Eddy Current Examination."

Notes:

(1) Use of 1989 Edition reflects applicable construction code year. The design specification meets the requirements up to the 2001 Edition, including the 2002 Addenda.

(2) Latest ASME issued.

(3) Code Case 2142-1 and Code Case 2143-1 have been incorporated into ASME Section II, Part C and ASME Section IX, 1998 Edition, 1999 Addenda. These welding consumables will be procured to ASME Section II, Part C, 2001 Edition.

Table 4.7-4
BVPS-1 Replacement Steam Generator NSSS Design (PCWG) Parameters

THERMAL DESIGN PARAMETERS	Case 1	Case 2	Case 3	Case 4
NSSS Power %	109.4	109.4	109.4	109.4
MWt	2910	2910	2910	2910
10^6 Btu/hr	9929	9929	9929	9929
Reactor Power MWt	2900	2900	2900	2900
10^6 Btu/hr	9895	9895	9895	9895
Thermal Design Flow, loop gpm	87,200	87,200	87,200	87,200
Reactor 10^6 lb/hr	101.1	101.1	99.3	99.3
Reactor Coolant Pressure, psia	2250	2250	2250	2250
Core Bypass, %	6.5	6.5	6.5	6.5
Reactor Coolant Temperature, °F				
Core Outlet	608.6	608.6	621.4	621.4
Vessel Outlet	603.9	603.9	617.0	617.0
Core Average	570.6	570.6	584.6	584.6
Vessel Average	566.2	566.2	580.0	580.0
Vessel/Core Inlet	528.5(1)	528.5(1)	543.1	543.1
Steam Generator Outlet	528.2	528.2	542.8	542.8
Steam Generator				
Steam Temperature, °F	500.5(2)	490.2(2)	515.8(3)	505.6
Steam Pressure, psia	684(2)	623(2)	783(3)	716
Steam Flow, 10^6 lb/hr total	12.02/12.97	12.01/12.95	12.06/13.01(3)	12.03/12.98
Feed Temperature, °F	400/455	400/455	400/455	400/455
Moisture, % max.	0.10	0.10	0.10	0.10
Tube Plugging Level (%)	0	22(4)	0	22(4)
Zero Load Temperature, °F	547	547	547	547
HYDRAULIC DESIGN PARAMETERS				
Mechanical Design Flow, loop gpm	101,400			
Minimum Measured Flow, gpm/total	266,800			

Notes:

(1) Vessel inlet temperature is limited to a minimum of 530°F due to reactor vessel embrittlement considerations.

(2) Steam conditions are limited to minimums of 700 psia and 503.1°F due to component design transient considerations.

(3) For analysis purposes, maximum steam conditions are 831 psia, 522.6°F and 13.04 x 10^6 lb/hr.

(4) Steam generator tube plugging is limited to 10% due to Small Break LOCA Analysis.

Table 4.7-5
BVPS-1 Replacement Steam Generator NSSS Design Transients

Condition	Number of Occurrences	
	Model 54F RSG 2910 MWt	Model 51 OSG[1] 2660 MWt (Original Design)
NORMAL CONDITIONS	–	–
Heatup and Cooldown at 100°F/hr	200 (each)	200 (each)
Unit Loading and Unloading at 5 Percent of Full Power/min	18,300 (each)	18,300 (each)
Step Load Increase and Decrease of 10 Percent of Full Power	2,000 (each)	2,000 (each)
Large Step Load Decrease	200	200
Steady State Fluctuations	Infinite	Infinite
Feedwater Cycling/Hot Standby[2]	18,300	18,300[2]
UPSET CONDITIONS	–	–
Loss of Load, without immediate turbine or reactor trip	80	80
Loss of Power (blackout with natural circulation in the RCS)	40	40
Loss of Flow (partial loss of flow one pump only)	80	80
Reactor Trip from Full Power	400	400
RCS Cold Overpressurization[3]	10 [3]	N/A
Operational Basis Earthquake (20 earthquakes of 20 cycles each)	400	400
FAULTED CONDITIONS	–	–
Main Reactor Coolant Pipe Break	1	1
Steam Pipe Break	1	1
Steam Generator Tube Rupture	1 (Included in upset condition item 4 above, Reactor Trip from Full Power)	1 (Included in upset condition item 4 above, Reactor Trip from Full Power)
Design Basis Earthquake	1	1
TEST CONDITIONS	–	–
Turbine Roll Test	10	10
Hydrostatic Test Conditions		
a. Primary Side	5	5
b. Secondary Side	5	5
c. Primary Side Leak Test	50	50

Notes:

(1) Design Transient information is from BVPS-1 UFSAR Table 4.1-10.

(2) The Feedwater Cycling/Hot Standby design transient is not shown in BVPS-1 UFSAR Table 4.1-10 but was included for original steam generator design.

(3) The RCS Cold Overpressurization design transient is not shown in BVPS-1 UFSAR Table 4.1-10 but is included for replacement steam generator design.

Table 4.7-6
BVPS-1 Replacement Steam Generator Materials of Construction

Component Section	Model 54F RSG	Model 51 OSG[1] (Original Design)
Pressure Plates	N/A[2]	ASTM A-533 Grade A Class 1
Pressure Forgings	SA-508 Class 3 or SA-508 Class 3a	ASTM A-508 Class 2
Cladding for Heads, Stainless	Type 309L or 308L	Type 309 or 308L
Cladding for Tubesheets	Alloy 690 welding consumables	Alloy (Inconel) 600 welding consumables
Tubes	Alloy 690 TT[3]	Alloy (Inconel) 600
Channel Head Castings	N/A[2]	ASTM A-216 Grade WCC

Notes:

(1) Materials of Construction information is from BVPS-1 UFSAR Table 4.2-1 (Deleted).

(2) Pressure Forgings are used for the RSG Secondary Shell and Primary Channel Head pressure boundary components.

(3) TT – Thermally Treated.

Table 4.7-7 BVPS-1 Replacement Steam Generator U.S. Nuclear Regulatory Commission (NRC) Requirements	
Code of Federal Regulations	
1.	10 CFR 20, Standards for Protection Against Radiation
2.	10 CFR 21, Reports of Defects and Noncompliance
3.	10 CFR 26, Fitness for Duty for Nuclear Power Plants
4.	10 CFR 50, Domestic Licensing of Production and Utilization Facilities
5.	10 CFR 100, Reactor Site Criteria
Regulatory Guides (RG)	
1.	RG 1.29, Seismic Design Classification, 1978.
2.	RG 1.31, Control of Ferrite Content in Stainless Steel Weld Metal, 1978.
3.	RG 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants, 1973.
4.	RG 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage and Handling of Items for Water-Cooled Nuclear Power Plants, 1977.
5.	RG 1.43, Control of Stainless Steel Weld Cladding of Low Alloy Steels, 1973.
6.	RG 1.44, Control of the Use of Sensitized Stainless Steel, 1973.
7.	RG 1.50, Control of Preheat Temperature for Welding of Low Alloy Steel, 1973.
8.	RG 1.54, QA Requirements for Protective Coatings Applied to Water Cooled Nuclear Power Plants, 1973.
9.	RG 1.60, Design Response Spectra for Seismic Design of Nuclear Power Plants, 1973.
10.	RG 1.61, Damping Values for Seismic Design of Nuclear Power Plants, 1973.
11.	RG 1.71, Welders Qualification for Areas of Limited Accessibility, 1973.
12.	RG 1.83, Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes, 1975.
13.	RG 1.84, Design and Fabrication Code Case Acceptability ASME Code Section III, Division 1, 1999.
14.	RG 1.85, Materials Code Case Acceptability ASME Code Section III, Division 1, 1999.
15.	RG 1.92, Combining Modal Responses and Spatial Components in Seismic Response Analysis, 1976.
16.	RG 1.121, Bases for Plugging Degraded PWR Steam Generator Tubes (Issued in Draft form), 1976.
17.	RG 1.147, Inservice Inspection Code Case Acceptability – ASME Code Section XI, Division 1, 1999.
18.	RG 8.8, Information Relevant to Ensuring that Occupational Radiation Exposure at Nuclear Power Stations Will Be As Low As Reasonably Achievable (ALARA), 1982.
19.	RG 8.10, Operating Philosophy for Maintaining Occupational Radiation Exposures as Low as is Reasonably Achievable (ALARA), 1977.

Table 4.7-7 (continued) BVPS-1 Replacement Steam Generator U.S. Nuclear Regulatory Commission (NRC) Requirements
Branch Technical Positions (BTP)
1. BTP ASB 10.2, Design Guidelines for Avoiding Water Hammer in Steam Generators, 1984.
NUREGs
1. NUREG-0800, Standard Review Plan, 1981.
2. NUREG-0918, Prevention and Mitigation of Steam Generator Water Hammer Events in PWR Plants, 1982.

Table 4.7-8
BVPS-1 Replacement Steam Generator NDE Test Requirements

RSG Component	RT (1)	UT (1)	PT (1)	MT (1)	ET (1)
Tubesheet					
Forging	–	Yes	–	Yes	–
Cladding	–	Yes (2)	Yes	–	–
Channel Head					
Forging	–	Yes	–	Yes	–
Cladding	–	Yes	Yes	–	–
Secondary Shell and Head					
Forgings	–	Yes	–	Yes	–
Tubes	–	Yes	–	–	Yes
Nozzle (forgings)	–	Yes	–	Yes	–
Safe Ends	–	Yes	Yes	–	–
Weldments					
Shell, Circumferential	Yes	–	–	Yes	–
Cladding (channel head – tubesheet joint)	–	Yes	Yes	–	–
Feedwater Nozzle to Shell	Yes	–	–	Yes	–
Support Brackets	–	–	–	Yes	–
Tube to Tubesheet(3)	–	–	Yes	–	–
Instrument Connections (primary and secondary)	–	–	–	Yes	–
Temporary Attachments After Removal	–	–	–	Yes	–
After Hydrostatic Test (all welds and major base metal repairs – where applicable)	–	–	–	Yes	–
Safe Ends to Nozzle Buttering	Yes	–	Yes	–	–

Notes:

(1) RT – Radiographic, UT – Ultrasonic, PT – Liquid (Dye) Penetrant, MT – Magnetic Particle, ET – Eddy Current.

(2) All surfaces for bond and flat surfaces also for defects.

(3) Helium Leak Test.

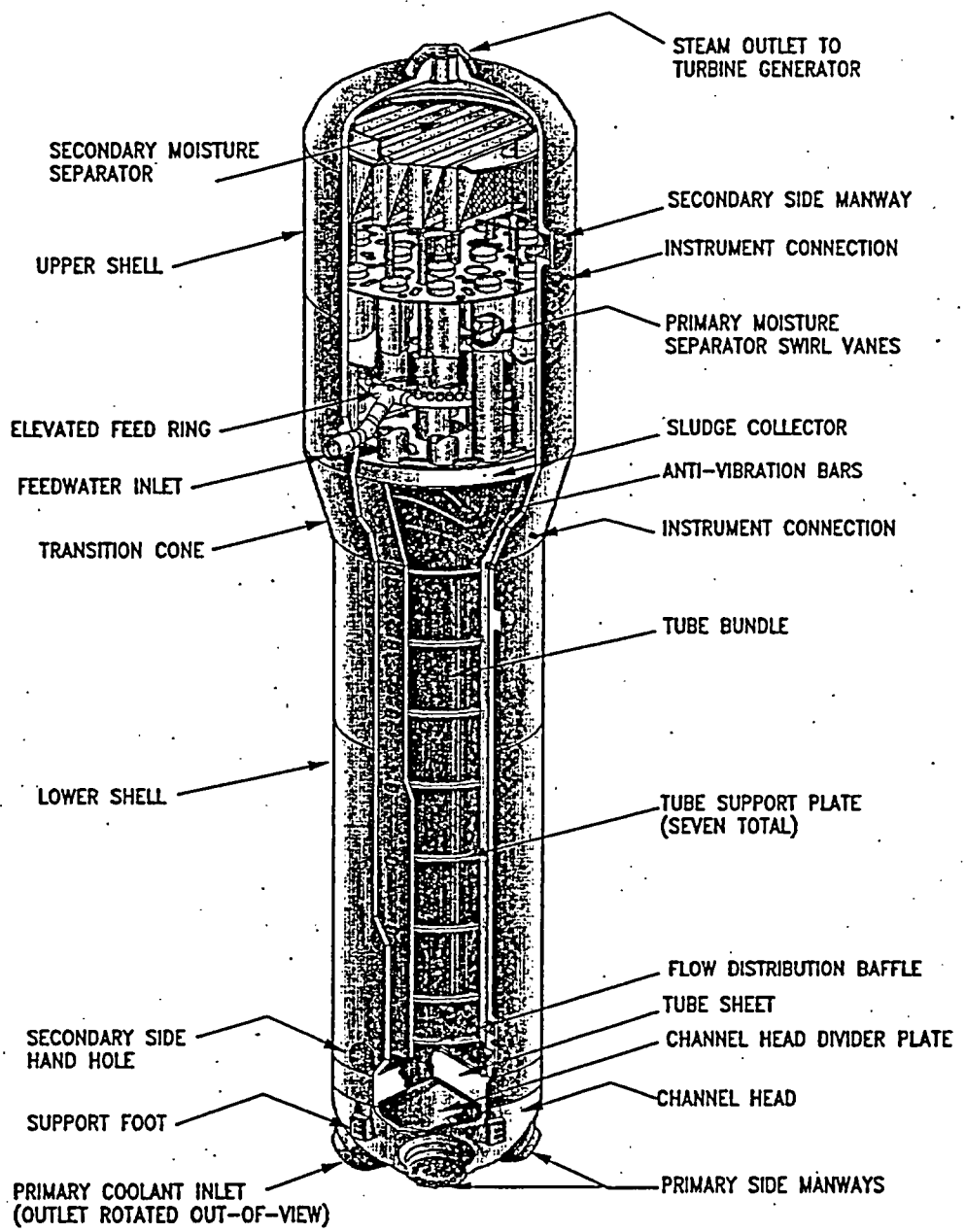

Figure 4.7-1
BVPS-1 Replacement Steam Generator

LAR 320 Enclosure 4

The following tables are offered as a reviewer's aid for Beaver Valley Power Station (BVPS) Unit No. 1 LAR 320, Replacement Steam Generators (RSG).

Table 1 lists all the changes submitted in the Extended Power Uprate (EPU) LAR (302) for BVPS Unit No. 1 and identifies the Technical Specification changes included in the RSG LAR.

Table 2 lists all the Licensing Report Section submitted in the EPU LAR and identifies those needed to support the Technical Specification changes included in the RSG LAR.

A brief discussion of the reason for the exclusion or inclusion of the Technical Specification change and Licensing Report Section is also provided.

Table 1 Technical Specifications Required in RSG LAR 320

No.	Tech Spec	Title	TS Change Required for RSG LAR	Reasons for Including/Not Including TS Changes In RSG LAR
		Proposed TS Changes		
1	License page 3	Item 2.C(1) Maximum Power Level	No	Increase in power level not required/current TS more limiting
2	License page 3	Item 2.C(2) Technical Specifications	No	Administrative change (deletion of Amendment Number) not required
3	1.0	DEFINITIONS – 1.3 RATED THERMAL POWER	No	Increase in power level not required/current TS more limiting
4	2.1.1.1	SAFETY LIMITS – REACTOR CORE	Yes	WRB-2M correlation required for EPU analyses
5	3.1.2.8	REFUELING WATER STORAGE TANK (RWST)	No	Increase in RWST temperature not required/current TS more limiting
6	3.3.1.1	REACTOR TRIP SYSTEM INSTRUMENTATION (Tables 3.3-1 and 4.3-1, FUNCTIONAL UNIT 4[s1] Power Range, Neutron Flux High Negative Rate Trip)	No	Administrative change (deletion of TS) not required/current TS more limiting
7	3.3.1.1 (RSG TS)	REACTOR TRIP SYSTEM INSTRUMENTATION (Table 3.3-1, FUNCTIONAL UNIT 14, Steam Generator Water Level – Low-Low)	Yes	SG level setpoint change required for RSG
8	3.3.1.1	REACTOR TRIP SYSTEM INSTRUMENTATION (Table Notation, Overtemperature/Overpower ΔT)	Yes	OTΔT and OPΔT equation changes required for EPU analyses
9	3.3.1.1	REACTOR TRIP SYSTEM INSTRUMENTATION (Table Notation – Action 8)	No	Administrative change not required
10	3.3.2.1	ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION (Table 3.3-3, Footnote to Steamline Pressure – Low)	No	Administrative change not required
11	3.3.2.1 (RSG TS)	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)	Yes	SG level setpoint changes required for RSG
12	3.4.1.3 (RSG TS)	REACTOR COOLANT SYSTEM – SHUTDOWN (SR 4.4.1.3.3)	Yes	SG level surveillance change required for RSG

Table 1 Technical Specifications Required in RSG LAR 320				
No.	Tech Spec	Title	TS Change Required for RSG LAR	Reasons for Including/Not Including TS Changes In RSG LAR
		Proposed TS Changes		
13	3.4.3	REACTOR COOLANT SYSTEM – SAFETY VALVES	No	Increase in lift setting tolerance not required/current TS more limiting
14	3.4.5 (RSG TS)	STEAM GENERATORS	Yes	TS surveillance changes required for RSG
15	3.4.8	REACTOR COOLANT SYSTEM – SPECIFIC ACTIVITY	No	Increase in specific activity not required/current TS more limiting
16	3.5.1	ACCUMULATORS	No	Accumulator pressure and level changes not required/current TS more limiting
17	3.5.4.1.1	BORON INJECTION TANK ≥ 350°F	No	Administrative change (Elimination of TS) not required
18	3.5.4.1.2 3.5.2 3.5.3	BORON INJECTION TANK < 350°F ECCS SUBSYSTEMS – Tavg ≥ 350°F ECCS SUBSYSTEMS – Tavg < 350°F	No	Administrative changes not required
19	3.5.5	SEAL INJECTION FLOW	Yes	Increase in surveillance value results in increase in minimum SI flow, which is required for SBLOCA analysis
20	3.7.1.1	TURBINE CYCLE – MAIN STEAM SAFETY VALVES (MSSVs)	No	Reduction in % power levels for MSSVs OOS not required for current RTP and increase in MSSV lift setting tolerance not required/current TS more limiting
21	3.7.1.3	PRIMARY PLANT DEMINERALIZED WATER (PPDW)	No	Change in volume not required for current RTP.
22	3.7.1.4	PLANT SYSTEMS – ACTIVITY	No	Increase in specific activity not required/current TS more limiting
23	6.9.5	CORE OPERATING LIMITS REPORT (COLR)	Yes	WRB-2M Correlation and VIPRE Computer Code required for EPU analyses

The RSG Licensing Report contains those sections from the EPU Licensing Report that provide the technical justification for Technical Specification and analysis methodology changes that deviate from the current licensing basis and, hence, cannot be performed under 10 CFR 50.59. Those sections that are not required to provide technical justification for Technical Specification or analysis methodology changes are being addressed under 10 CFR 50.59 and, hence, are not included in the RSG Licensing Report.

Table 2 RSG Licensing Report (LR) Sections Required in RSG License Amendment Request (LAR 320)

LR Section Number	Area	Technical Specification Change No.								Include in LR	Reasons for Including In LAR/LR
		4	7	8	11	12	14	19	23		
1	Introduction									Yes	Introduces RSG LAR and LR approach
2	NSSS Analysis									Yes	Introduces NSSS analysis sections
2.1	NSSS Parameters									Yes	Introduces NSSS Parameters analysis sections
2.1.1	Design (PCWG) Parameters		Y	Y	Y					Yes	Presents PCWG Parameters that support other analysis sections
2.1.2	BE Parameters									No (EPU Section)	
2.1.3	Tavg Coastdown Parameters									No (EPU Section)	
2.2	Design Transients									No (EPU Section)	
3	NSSS Systems									Yes	Introduces NSSS Systems analysis sections
3.1	NSSS/BOP Interfaces									No (EPU Section)	
3.2	NSSS Control Systems									Yes	Introduces NSSS Control Systems analysis sections
3.2.1	Stability/Operability									Yes	Introduces NSSS Control Systems Stability/Operability
3.2.1.1	Stability/Setpoints									No (EPU Section)	
3.2.1.2	Plant Operability Margins		Y	Y	Y					Yes	Supports TS changes for ΔT and RSG level setpoints
3.2.1.3	P-9 Setpoint									No (EPU Section)	
3.2.2	Component Sizing									No (EPU Section)	
3.2.3	COMS									No (EPU Section)	
4	NSSS Components									Yes	Introduces NSSS Components analysis sections
4.1	Reactor Vessel									No (EPU Section)	
4.2	Reactor Vessel System									No (EPU Section)	
4.3	Fuel Assemblies									No (EPU Section)	
4.4	CRDMs									No (EPU Section)	
4.5	Reactor Coolant Loop Piping									No (EPU Section)	
4.6	Reactor Coolant Pumps									No (EPU Section)	
4.7	Steam Generators									Yes	Introduces steam generators analysis sections
4.7.1	BVPS-1 Replacement SGs		Y		Y	Y	Y			Yes	Supports TS changes for RSG level setpoints, level surveillance requirement during shutdown, and inspection surveillance requirements
4.7.2	BVPS-2 Original SGs									No (EPU Section)	
4.8	Pressurizer									No (EPU Section)	

Table 2 RSG Licensing Report (LR) Sections Required in RSG License Amendment Request (LAR 320)

LR Section Number	Area	Technical Specification Change No.								Include in LR	Reasons for Including In LAR/LR
		4	7	8	11	12	14	19	23		
4.9	NSSS Auxiliary Equipment									No (EPU Section)	
4.10	Loop Stop Isolation Valves									No (EPU Section)	
5	Safety Analysis									Yes	Introduces Safety Analysis sections
5.1	Initial Condition Uncertainties		Y		Y					Yes	Supports TS changes for RSG level setpoints
5.2	LOCA Transients									Yes	Introduces LOCA analysis sections
5.2.1	Large Break LOCA									Yes	Supports continuity with the BELOCA LAR
5.2.2	Small Break LOCA							Y		Yes	Supports TS change for seal injection pressure
5.2.3	Hot Leg Switchover									No (EPU Section)	
5.2.4	Post-LOCA Subcriticality/LTCC									No (EPU Section)	
5.2.5	CREA Steam Releases									No (EPU Section)	
5.3	Non-LOCA Transients									Yes	Introduces Non-LOCA analysis sections
5.3.1	Introduction	Y	Y	Y	Y				Y	Yes	Introduces Non-LOCA analysis sections
5.3.2	RCCA From Subcritical								Y	Yes	Supports TS changes for VIPRE
5.3.3	RCCA at Power	Y		Y					Y	Yes	Supports TS changes for ΔT setpoints & WRB-2M/VIPRE
5.3.4	RCCA Misalignment	Y							Y	Yes	Supports TS changes for WRB-2M/VIPRE
5.3.5	Uncontrolled Boron Dilution			Y						Yes	Supports TS changes for ΔT setpoints
5.3.6	LOL/TT	Y		Y					Y	Yes	Supports TS changes for ΔT setpoints & WRB-2M/VIPRE
5.3.7	Loss of Normal FW		Y		Y					Yes	Supports TS changes for RSG level setpoints
5.3.8	Loss of AC Power		Y		Y					Yes	Supports TS changes for RSG level setpoints
5.3.9	FW System Malfunction	Y			Y				Y	Yes	Supports TS changes for RSG level setpoints & WRB-2M/ VIPRE
5.3.10	Excessive Load Increase	Y							Y	Yes	Supports TS changes for WRB-2M/VIPRE
5.3.11	Accidental RCS Depress	Y		Y					Y	Yes	Supports TS changes for ΔT setpoints & WRB-2M/VIPRE
5.3.12	Rupture Main Stm Pipe (HZP)								Y	Yes	Supports TS changes for VIPRE
5.3.13	Partial Loss RCS Flow	Y							Y	Yes	Supports TS changes for WRB-2M/VIPRE
5.3.14	Complete Loss RCS Flow	Y							Y	Yes	Supports TS changes for WRB-2M/VIPRE
5.3.15	RCP Locked Rotor	Y							Y	Yes	Supports TS changes for WRB-2M/VIPRE
5.3.16	RCCA Ejection									No (EPU Section)	
5.3.17	Rupture Main Feed Pipe		Y		Y					Yes	Supports TS changes for RSG level setpoints
5.3.18	Spurious Operation of SI									No (EPU Section)	
5.3.19	Steam Pipe Break at HFP	Y		Y					Y	Yes	Supports TS changes for ΔT setpoints & WRB-2M/VIPRE
5.3.20	Summary	Y	Y	Y	Y				Y	Yes	Summarizes Non-LOCA analysis sections
5.4	Steam Generator Tube Rupture									Yes	Introduces SGTR analysis section
5.4.1	BV1 SGTR TH for Doses									Yes	Supports continuity with Radiological Assessment section

Table 2 RSG Licensing Report (LR) Sections Required in RSG License Amendment Request (LAR 320)

LR Section Number	Area	Technical Specification Change No.								Include in LR	Reasons for Including In LAR/LR
		4	7	8	11	12	14	19	23		
5.4.2	BV2 SGTR Overfill									No (EPU Section)	
5.4.3	BV2 SGTR TH for Doses									No (EPU Section)	
5.5	LOCA M&Es									Yes	Supports continuity with the CC LAR
5.6	MSLB M&Es									Yes	Introduces MSLB M&E analysis sections
5.6.1	MSLB M&Es Inside Cmnt									Yes	Supports continuity with the CC LAR
5.6.2	MSLB M&Es Outside Cmnt		Y	Y						Yes	Supports TS changes for ΔT and RSG level setpoints
5.6.3	Steam Releases for Doses									Yes	Supports continuity with Radiological Assessments section
5.7	LOCA Forces									No (EPU Section)	
5.8	ATWS									No (EPU Section)	
5.9	Natural Circulation/Cooldown									No (EPU Section)	
5.10	RTS/ESFAS Setpoints		Y	Y	Y					Yes	Supports TS changes for ΔT and RSG level setpoints
5.11	Radiological Assessments									Yes	Supports an expanded selective implementation of AST methodology
5.12	Fire Protection Safe Shutdown									No (EPU Section)	
6	Fuel Analysis									Yes	Supports continuity with Fuel T-H section
6.1	Fuel T-H Design	Y		Y					Y	Yes	Supports TS changes for ΔT setpoints (core safety limits) and WRB-2M/VIPRE
6.2	Fuel Core Design									No (EPU Section)	
6.3	Fuel Rod Design									No (EPU Section)	
6.4	Reactor Internal Heating Rates									No (EPU Section)	
6.5	Neutron Fluence									No (EPU Section)	
7	Containment Analysis									Yes	Supports continuity with the CC LAR
8	BOP Analysis									No (EPU Section)	
9	Plant Systems									No (EPU Section)	
10	Generic Programs									Yes	Introduces Generic Programs sections
10.1	MOV Program									No (EPU Section)	
10.2	AOV Program									No (EPU Section)	
10.3	GL 89-13 Monitoring									No (EPU Section)	
10.4	ISI Program									No (EPU Section)	
10.5	IST Program									No (EPU Section)	
10.6	Cmnt. Leak Rate Testing									No (EPU Section)	
10.7	Station Blackout									No (EPU Section)	
10.8	Human Factors									No (EPU Section)	
10.9	Plant Simulator									No (EPU Section)	

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LR Section Number	Area	Technical Specification Change No.								Include in LR	Reasons for Including In LAR/LR
		4	7	8	11	12	14	19	23		
10.10	Equipment Qualification		Y	Y						Yes	Supports TS changes for ΔT and RSG level setpoints
10.11	Seismic/Dynamic Qualification									No (EPU Section)	
10.12	Flood Protection									No (EPU Section)	
10.13	Missiles Inside & Outside Cmnt									No (EPU Section)	
10.14	Protective Coating Systems									No (EPU Section)	
10.15	Station Procedures/Training									No (EPU Section)	
10.16	Impact on Plant Risk									No (EPU Section)	
11	Environmental Impacts									No (EPU Section)	
12	Decommissioning									No (EPU Section)	
13	Testing									No (EPU Section)	